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Controlled Document

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Summary

Storage Development Plan summarising the three key elements of the Quest CCS plan: The CO2 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 CO2 pipeline, which will transport the CO2 from the Scotford Upgrader to the injection wells. Storage of the CO2 through 3 to 8 injection wells, which will inject the CO2 into the Basal Cambrian Sands (BCS), a deep saline geological formation, for permanent storage at a depth of about 2 km below ground level

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Quest, CCS, AOSP, Field Development Plan, Storage Development Plan

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1. EXECUTIVE SUMMARY

1.1. 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, has already applied 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 (CO2), 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:

- CO2 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 CO2 pipeline, which will transport the CO2 from the Scotford Upgrader to the injection wells
- Storage of the CO2 through 3 to 8 injection wells, which will inject the CO2 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 CO2 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 CO2 emissions from the Scotford Upgrader by up to 35%, capturing and storing up to 1.2 million tonnes of CO2 per year. The capture infrastructure will use amine absorbers to capture approximately 80% of the CO2 from the process gas stream produced by the HMUs. The captured CO2 will be dehydrated and compressed to up to 14MPa prior to entering the pipeline.

The CO2 from the Scotford Upgrader will be transported to the storage area using a single high-vapour-pressure 12" 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 pipeline will operated under single phase flow with the CO2 in the dense phase to avoid flow assurance issues.

The 3 to 8 wells required for injecting the CO2 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 6" laterals, all assumed to be less than 15 km long. The BCS is overlain by a number of formations which provide containment for the CO2. The base case is for a 5 well development although the results of the Radway 8-19 appraisal well drilled Q3 2010 has highlighted an opportunity to reduce the well count to 3 going forward. This has been built into the project planning and is reflected in the phasing of the drilling and staged pipeline purchase and development. This means that in 2012 after drilling development wells 2 and 3 there is a major decision to be made in terms of final number of wells and therefore an update to this document required.

The storage component is accompanied by a detailed Measurement, Monitoring and Verification program designed to prove containment and conformance both of which are key criteria to support the final site closure and hand-over of liability to the Crown at the end of project life. Some elements of the MMV scope are tightly tied to the final number of injection wells such as the number of groundwater monitoring wells and will also need to be revisited in 2012.

1.2. Project Phasing

Due to the unusual nature of a CCS project into a saline aquifer an iterative subsurface workflow has been adopted to ensure project delivery against key milestones which has meant a greater than normal level of subsurface uncertainty has been carried through to the define phase as appraisal data was still being gathered while project decisions were being made. This document represents the first time that all three elements of the project are at an approximately equivalent state of maturity and discusses the plans to deliver the project through the Execute phase.

Execute:

- Construction of the CO2 capture infrastructure is expected to start in Q3 2012,
- Pipeline construction is phased with between Q3 2012 for inside the Scotford fenceline to Q4 2013 when the main pipeline and laterals will be drilled.
- The injection wells will also be phased to realise an opportunity to limit the final number of injection wells to 3. This means that development wells 2 & 3 will be drilled in Q2/Q3 2012 with a further phase of drilling planned in Q2/Q3 2013 if the full 5 well base case is required.
- MMV baselining will start in Q2 2012 to take account of seasonal variations and will ensure baseline data is collected across all domains, atmosphere, biosphere, hydrosphere and geosphere.
- Commission and start-up of the operation is anticipated to begin in January 2015.

Operations (Injection)

- The lifespan of the Project is considered to be for the life of the Scotford Upgrader (greater than 25 years).
- The subsurface development has been designed to take the full 1.08 Mtpa for 25 years in all subsurface realisations including the low case. This means that in the base case

or high case realisations there is the potential for storage growth either in terms of increasing the storage life or increasing the injection rate. The choice of pipeline size also supports the potential for growth if required.

- Key controls and shut-in procedures have been identified based on composition, water content and pressure.

Closure and Post-Closure

- This is followed by a Closure Period during which the site will continue to be monitored in terms of both containment and conformance.
- Following the completion of site closure activities, Shell will apply for a Site Closure certificate, this will transfer the long-term liability and any further post-closure activities from Shell to the Crown.
- The MMV Plan and Closure Plan have been designed to support this transfer of liability to the Crown.

1.3. Project Value Drivers

Quest CCS will not generate revenues other than via Carbon Credits, the Quest project will receive multi-credits (2 per tonne of CO2). The current pricing of these credits is approximately $15 per tonne of CO2. It is therefore essential for the Quest CCS Project to be developed such that CAPEX, OPEX, and GHG efficiency are optimized, resulting in the greatest possible value for AOSP.

Although cost is the primary driver for this project, quality is also important, as it is a demonstration project with significant Government funding and public interest. If production and availability are not attained as planned, project economics will be significantly impacted.

The following are the project drivers in order of importance:

- Cost – This is the primary project driver because the Quest facilities will not generate any revenue except via carbon credits.
- Quality – This is the secondary project driver, because part of the government funding is tied to sequestering a specified amount of CO2 (10.8 Mt) by a specified date (December 2025). If this is not achieved, part of the funding will be pro-rated accordingly.
- Schedule – The strategy for Quest is to achieve sustained operations (S.O.) in May 2015. However, if the execution schedule starts to slip, money will not be spent to maintain this schedule, as the commitment to the government is to achieve S.O. by December 2015. Moreover, government funding is not significantly impacted unless S.O. slips past December 2017.

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2. THE QUEST OPPORTUNITY

2.1. Background

To continue meeting the world's growing energy demand, while reducing greenhouse gas (GHG) emissions, several pathways must be pursued. Carbon Capture and Storage (CCS) is one of the six pathways that Shell is progressing along with increasing energy efficiency, low CO_2 fuel options, and advocating more effective CO_2 regulations, to reduce GHG emissions. The Athabasca Oil Sands Project Joint Venture (AOSP JV) owners – Shell Canada Energy (Shell), Chevron Canada Limited (Chevron) and Marathon Oil Sands L.P. (Marathon) – are advancing the front-end development work for a fully integrated carbon capture, pipeline and storage project in Alberta called the Quest CCS 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 offered by the Quest CCS Project. In the absence of the Quest CCS Project as an offset, Shell would advance 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

2.1.1. Canada and Alberta Climate Change Objectives

At the United Nations Climate Change Conference in Copenhagen in 2009, Canada announced its goal to cut CO2 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 CO2 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 CO2 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 CO2 emissions by 325 Mt by 2050 *(Figure 2-1 CCS Technology in the Reduction of CO2 Emissions in Canada (Source: NTREE(2008))).*

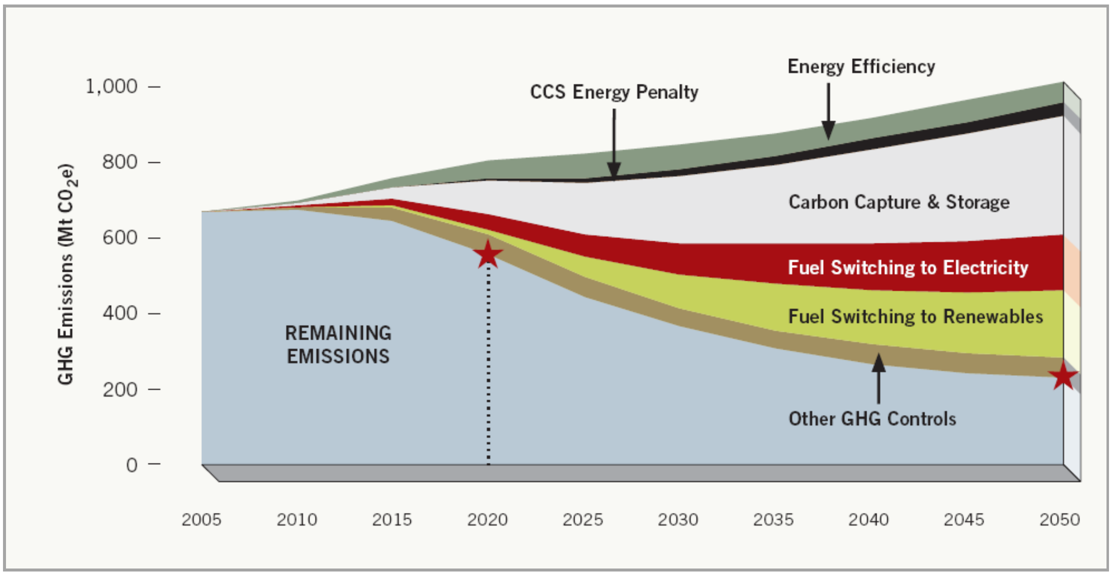


Figure 2-1 CCS Technology in the Reduction of CO2 Emissions in Canada (Source: NTREE(2008))

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 CO2 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 CO2 emissions of 200 Mt by 2050 *(Figure 2-2 CCS Technology in the Reduction of CO2 Emissions in Alberta (Source: GOA (2008)))*.

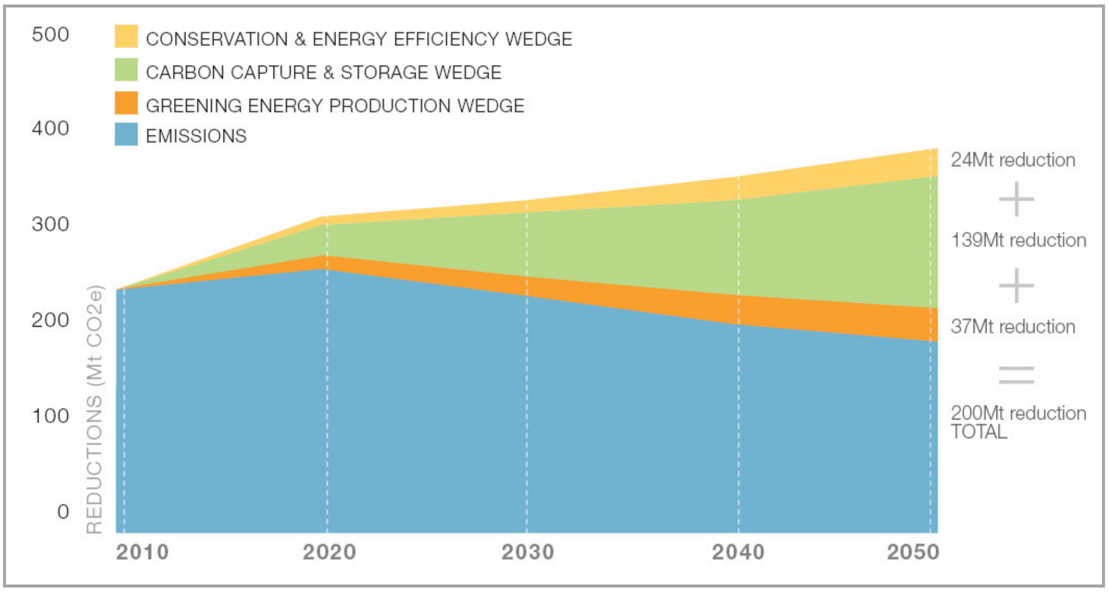


Figure 2-2 CCS Technology in the Reduction of CO2 Emissions in Alberta (Source: GOA (2008))

2.1.2. Shell's CO_2 Emission Abatement Strategy

The Quest CCS Project will capture, transport, and store up to 1.2 Mt/a of CO2 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.

Further, the Quest CCS Project will support Alberta and Canada's drive to address climate change as part of a global effort, and as such 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 CO2 from 2015 onward – a material contribution to sustaining a key driver of the economic prosperity in Alberta
- Demonstrating and unlocking CO2 storage capacity in a deep saline formation, which is essential for Alberta to meet its climate change strategy goals of 50 Mt/a of CO2 storage by 2020 and 139 Mt/a storage by 2050
- Promoting innovation for Alberta through the development and deployment of CO2 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 CO2 capture between 2015 and 2020.

2.2. Project Description

Quest is a fully integrated CCS project in the oil sands sector involving CO_2 capture at the Scotford Upgrader near Fort Saskatchewan, pipeline transportation northeast from Scotford and CO_2 storage in a deep saline formation zone. The project will:

- Capture and store CO2 from the steam methane reformer units at the existing Scotford Upgrader and at the upgrader's expansion currently undergoing production start-up.
- The CO2 will be compressed and transported via pipeline northeast of Scotford site
- The CO2 will be stored underground (2,000 to 2,100 m) in a deep, highly saline aquifer formation (Basal Cambrian Sand).

Although not envisaged at this time the project will also make provision for CO_2 to be made available for a possible future use in commercial EOR projects in Alberta, via the provision of a

T piece in the pipeline positioned inside the Scotford Upgrader fenceline. The following key elements should be noted:

- No commercial agreement is in place at this time for CO2 EOR offtake and therefore this option is not discussed in more detail in the Storage Development Plan.
- The funding agreement with the Government of Alberta categorically states that a minimum of 51% of the captured CO2 volume must go to saline aquifer storage.

The Commitment is for the capture, transport and injection of approximately 1.1 Mtpa of CO_2 is expected to begin towards the end of 2015 for a period of 10 years. However, the Quest design case is for approximately 1.1 Mtpa of CO_2 for 25 years of capture and storage, which is linked to the operational life of the Scotford heavy oil upgraders. The CO_2 injection stream will be dehydrated, relatively pure (98%), and contains no H_2S.

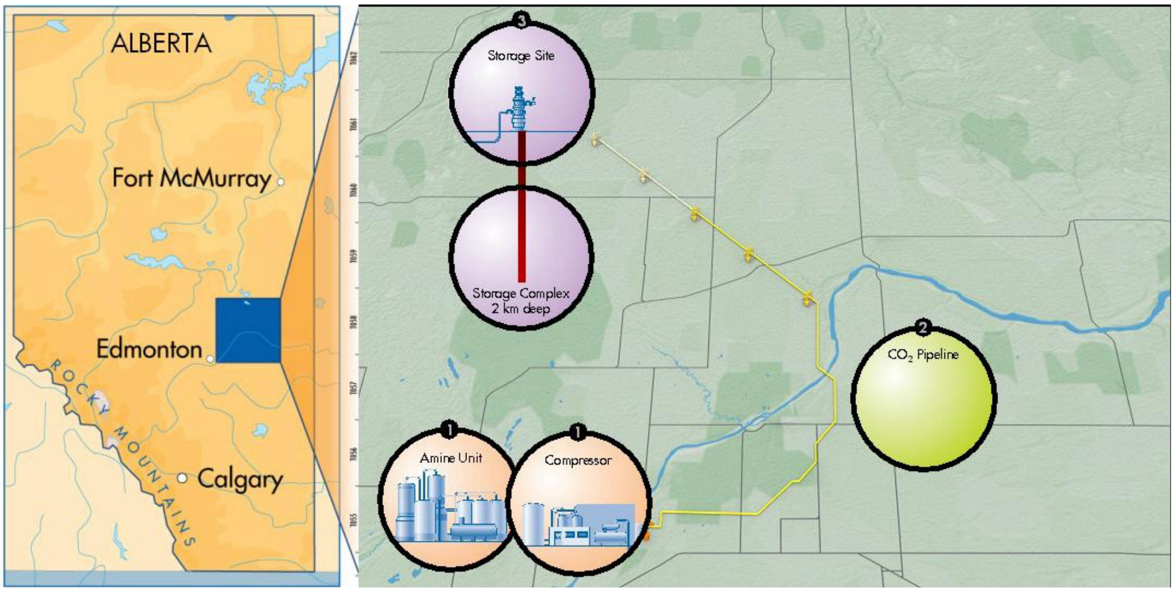


Figure 2-3 Schematic View of the Quest CCS Project in Alberta, Canada

2.3. Definition of Success (the Opportunity)

The Quest project is intended to store up to 1.2 million tonnes of year of CO_2 safely in the BCS formation from 2015 onwards. Design life has been set at 25 years, nominally linking the project to the remaining design life of the Scotford Upgrader.

As CCS projects are not commercially economic today, and certain aspects of the technology can be considered novel, in addition to the typical major project success factors there are a number of unique success factors that will require to be addressed.

- Deliver the project without harm to people (Goal Zero)

- Secure and maintain public support for Quest, particularly in the vicinity of the storage area (Thorhild & Radway)
- Secure a total of $865 mln of Federal and Provincial Government funding:
    - $745 mln from Government of Alberta
    - $120 mln from the Federal Government of Canada
- Store up to 27 mln tonnes of CO_2 over 25 years
- Handover of the site free and clear, post-closure to Government of Alberta
    - No CO_2 or BCS brine to 'leak' from the storage complex
    - An MMV plan that is capable of demonstrating both containment and conformance.
- Be considered to have fulfilled the extensive knowledge sharing obligations, and in particular de-risked the BCS as a major storage site for the Government of Alberta
- Breakeven at premise CO_2 price
    - Access to multiple CO_2 credits have been negotiated to help close the economic gap whilst the CO_2 prices remain low compared to the cost of abatement.

2.4. Government Funding Agreements

2.4.1. Background

On March 31, 2009, Shell submitted a Full Project Proposal (FPP) for the Quest Project [Ref 2.1] on behalf of the AOSP Joint Venture Owners. Subsequent to this, the Government of Canada (GoC) announced the creation of a Clean Energy Fund that also made funding available for CCS projects. Shell was invited to submit the FPP to Natural Resources Canada, the administrators of the Clean Energy Fund, and did so on July 2, 2009.

Non-binding letters of intent were successfully negotiated with the GoA and the GoC for $865 million total funding (GoC $120 million; GoA $745 million), subject to the execution of binding funding agreements. Subsequent negotiations were successfully conducted and concluded on June 24, 2011.

2.4.2. Key Terms

The key terms include the following:

- The GoC contributes $120 million over the period of July 2, 2009 to March 31, 2014. This federal funding is payable as Project costs are incurred, except all funding is withheld until the Canadian Environmental Assessment Act requirements are met and a final 10% is withheld until the agreement requirements are satisfied.

- The GoA contributes $745 million of the Project costs over the period of January 1, 2009 to December 31, 2025. This provincial funding is payable in the following instalments:
  - 40% in instalments up to the start of commercial operation
  - 20% upon achieving commercial operation (see commercial operation criteria below)
  - up to 40% in up to 10 annual instalments following commercial operation based on the net tonnes of CO2 sequestered in each year relative to design rates
- There is no obligation to complete the Quest CCS Project. The Owners retain the right to terminate the Quest CCS Project at any time, including at or prior to making a final investment decision, but, if the project is terminated before commercial operation is achieved, all funding must be returned to the governments.
- Shell, on behalf of the Owners, must reimburse the governments for the full amount of the funding if the Project fails to achieve commercial operation by December 31, 2017.
- If the Project becomes profitable, funding may be withheld or may need to be returned.
- There are extensive reporting requirements and a large amount of information about the Project will be made public (with specified exceptions, including proprietary and confidential information). Knowledge Management Plan

2.4.2.1. Commercial Operation Criteria

- **Test A – Capture Unit Capacity** – 24 consecutive hours in which Quest capture unit processes a minimum of 2,960 tonnes of CO2 (1.08 Mtpa over 24 hours) from the HMU facilities.
- **Test B – Capture Unit Efficiency** – 20 consecutive days in which the Quest capture unit processes a minimum of 75% of the total CO_2 produced by the Upgrader base and expansion HMU facilities during those 20 days, while running at an average of at least 50% and a minimum of at least 30% of design rates.
- **Test C – Integrated Project Reliability** – 30 consecutive days in which the Quest project maintains operation whereby the capture, transportation and subsurface facilities operate continuously without shutting down, while running at an average of at least 30% of design rates.

2.5. Project Milestones (roadmap)

The Quest project conforms to Shells project management standard using the Opportunity Realisation Manual (ORM) to define the decision driven milestones for successful maturation of this CCS opportunity. The ORM sets out a rigorous approach to the management of opportunities to ensure they are appropriately defined, evaluated and executed. Opportunities are developed through six phases *Figure 2-4 ORM Project Phase* for each phase there are clear decisions and deliverables requirements. The system uses a rigorous step-by-step approval process to ensure that quality is assured, risks are assessed, and that value is maximised from phase to phase and across the full TECOP, Technical, Economic, Commercial, Organisational and Political range of the opportunity.

It should be noted that there are some notable differences from the ORM process as applied to a CCS project relative to hydrocarbon project. This is partially a reflection of the reversed flow of the molecules and the fact that this is an NPV zero project which has the following implications:

1) Project identification is dependent on securing the CO2 source. Therefore a significant amount of surface engineering design is undertaken early on in the project cycle.
2) Subsurface screening work is only initiated once a supply of CO2 has been identified.
3) Moving the subsurface work through the assess phase is associated with significant FEASEX in terms of data acquisition (seismic, appraisal wells etc). Therefore there was limited appetite to invest in a capital intensive appraisal study until the funding is secured.
4) This means that as the project moves through the various phases of the ORM there is a larger than normal range of subsurface risks and uncertainty needed to managed with an iterative workflow
5) The lack of a complete Regulatory Framework for an integrated CCS project, including the absence of pore space legislation, a lack of certainty around long term liability, the lack of appropriate regulatory tools for approving multiple well disposal schemes has meant that a considerable amount of regulatory risk has had to be managed in the design phase of the project. In addition, the absence of key project information (such as number of wells, location of wells, until now) required a unique regulatory strategy.

The points above means that the various workflow elements have matured at a different rate as shown in *Figure 2-5 Quest Integrated Roadmap - An overview of the integrated venture roadmap leading to full injection capacity by 2015*. To manage this risk an iterative integrated reservoir modeling workflow has been adopted by the subsurface team to enable key project milestones and decisions to be taken while still maturing the subsurface (Appendix 1). However, this means that a greater than usual amount of uncertainty has been carried forward on the subsurface at each VAR gate relative to a more standard workflow. Equally, it means that the VAR4 documentation, of which the Storage Development Plan is part, is the first instance where all major project elements are at a similar level of maturity.

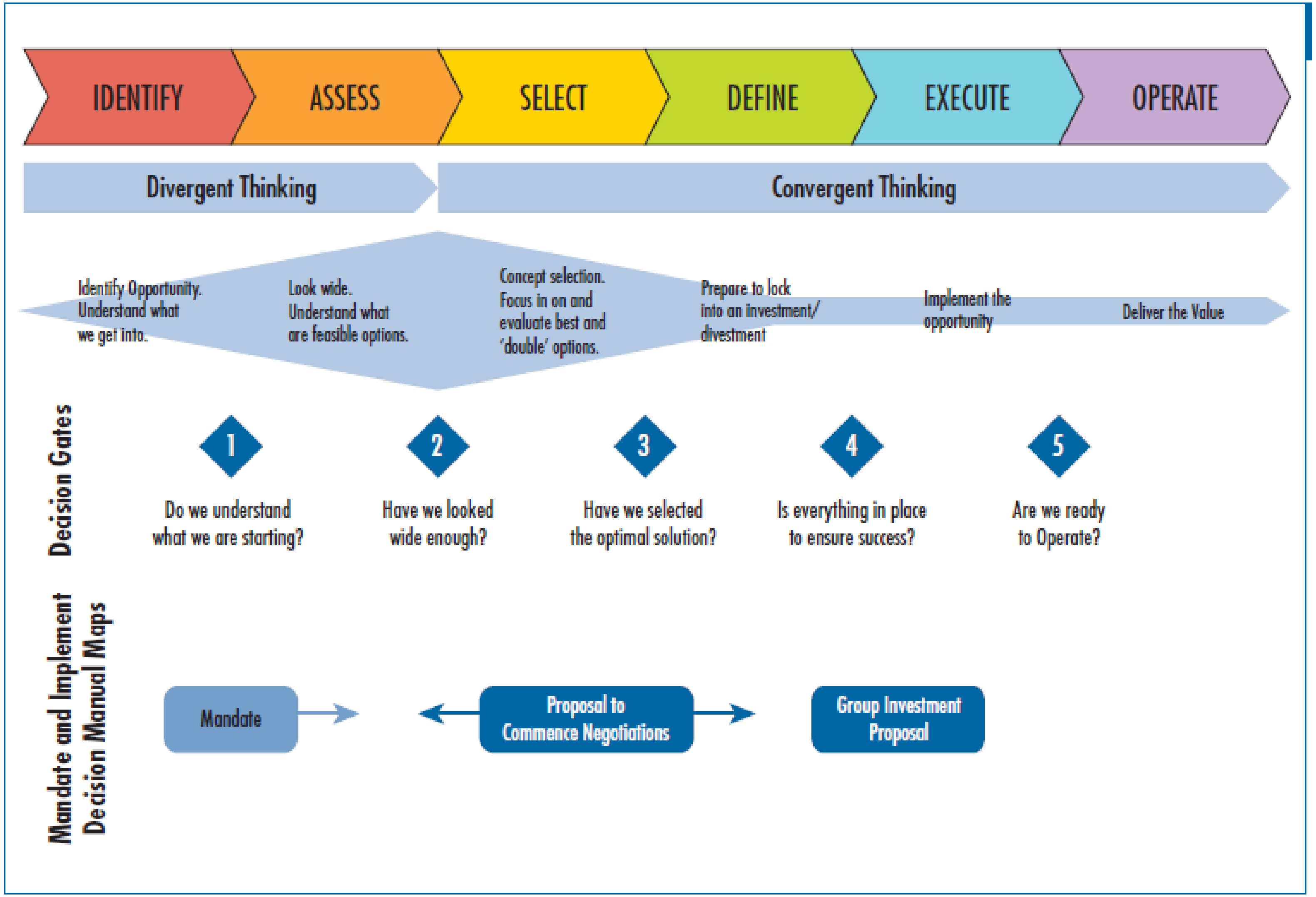
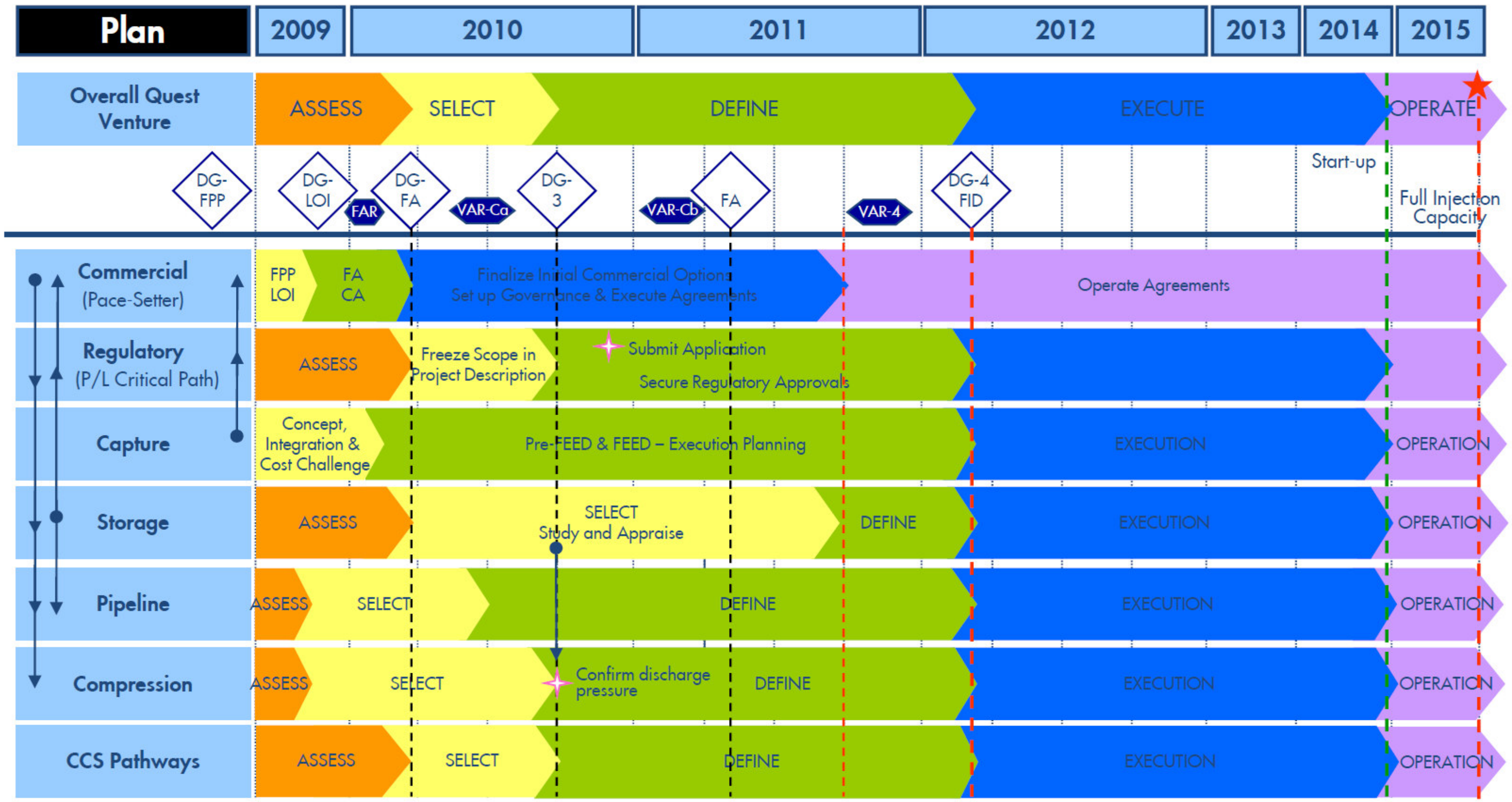


Figure 2-4 ORM Project Phase



FAR = Funding Assurance Review: Support FA, approve Pre-FID funding (for Pre-FEED/FEED and appraisal campaign) and regulatory strategy

VAR-Ca = Integrated Review: Support upside capacity from commercial negotiations, scope & project description for regulatory submission, and assessment of public support

VAR-Cb = Verification Assurance Review, confirm selected concept (no surprises, nor major changes required), update project description for regulatory application, assessment of public support

VAR-4 = "Typical" VAR-4, all areas aligned by September 2011 at end of Capture Define phase. Project is ready to move into Execution phase

Figure 2-5 Quest Integrated Roadmap - An overview of the integrated venture roadmap leading to full injection capacity by 2015

- **Identify Phase**

  The Quest CCS project successfully completed the Identify Phase in Q2 2009.

  This phase was completed with an integrated scoping of the capture, pipeline and storage of CO2 from the Scotford Upgrader with the following key deliverables:

  - An EC approved PCN for the submission of the FPP to the GoA
  - The Full Project Proposal for the Quest CCS Project [Ref 2.1].
  - Draft letter of intents with both the Federal and Provincial Governments with funding offers from the GoA of Cdn $745 mln and the GoC Cdn $120 mln.

- **Assess Phase**

  The Assess Phase of the project was completed with the Funding Assurance Review in Q2 2010. The key deliverables for this phase were:

  - Commercial:
    - An assessment of the viability of the Quest CCS Project in the context of providing adequate assurance that Shell and the Athabasca Oil Sands Project (AOSP) Owners could sign the two major government funding agreements.
    - The review focused on the risks for the project associated with the agreements to ensure they were all identified, evaluated and were appropriately managed.
    - In July 2010 and updated PCN was approved by RDS EC to proceed with Signing FA with conditions ([Ref 2.2] Quest PCN update, June 2010)
  - Technical
    - The original exploration pore space tenure submission later replaced by the Sequestration Lease Application in 2011. (The three Quest wells to date were actually drilled on a "Consent to Drill and Test' issued by Alberta Energy).
    - An appraisal strategy was developed and implemented including a geophysical and wells program.
    - An iterative modeling strategy was developed and implemented.
    - GEN-2 IRM close-out was used to :
      - Develop an exploration pore space tenure request
      - Ensure project feasibility against all potential subsurface realizations with a focus on the downside.

- **Select Phase**

  The Select Phase was completed in December 2010. The objectives of this phase are to:

    - Have all strategic decisions required for the project approved by the appropriate authorities.

- Complete the data collection and appraisal well drilling to support site selection
- Rank and select a single integrated concept from the Quest development options.

- The key characteristic of this phase are the various levels of maturity that existed with the Quest venture by virtue of being a demonstration CCS project. The Capture scope for the project needed to be identified and defined much earlier than the subsurface, there is only a project if there is a technical solution to capture. This meant that the uncertainty ranges in the Storage scope significantly outweighed uncertainties in other elements of the project during this period.

  The key deliverables for this phase were:

  - Deliver the Appraisal and Integrated Reservoir Modelling Plan
    - These activities cross both the select and define phases. This was recognized early and a dedicated appraisal [Ref 2.3] and iterative integrated reservoir modeling strategy [Ref 2.4] was put in place to ensure subsurface uncertainty could be sufficiently reduced prior to FID and to align all elements of the Project to pass through VAR4 before this date.
    - The Quest Subsurface Appraisal Strategy enabled focussed cost-effective reduction of geological storage risks through the application of a range of complementary appraisal methods. Many appraisal activities occurred in parallel to accelerate the process of site characterization and provide timely support for regulatory requirements, field development planning and project de-risking. Most appraisal activities were carried out in 2010 and included the execution, processing and interpretation of High Resolution AeroMagnetics (HRAM), 415 km2 of 3D surface seismic, the drilling and testing of the first Project injection well, Radway 8-19, and a number of feasibility studies to help mature the MMV plan.
  - The decision to move the capture and pipeline engineering work into FEED.
    - The critical decision being made at this point in time was the compressor and pipeline design. To support this decision an early IPSM and Pipesim model was built to ensure that the operating envelope was suitable for all potential subsurface scenarios.
  - Regulatory submission – to support the requirement that all Regulatory approvals were in place by FID in Q1 2012 it was necessary to submit all regulatory approvals by Nov 30 2010.
    - This meant that the D65 subsurface regulatory submission was made based on only partial data availability and interim modeling results due to the ongoing appraisal campaign. A key deliverable was to make the D65 broad enough to cover the remaining subsurface uncertainty. For this reason a range of 3-10 wells was carried to ensure even in the low case reservoir scenario there was an integrated project solution.

  - A logic and workflow for the MMV plan was developed and submitted although based on only partial information.

- **Define Phase**

The Quest project is currently in the define phase which will be closed when FID is taken in Q1 2012.

The key deliverables for this phase are:

- Finalise the Appraisal plan and Integrated Reservoir Modelling Plan Deliverables
  - Complete the acquisition of the 3D seismic and confirm well locations submitted in D65
  - Complete the testing and analysis of the appraisal well and confirm results/impact on the regulatory submission
  - Subsurface appraisal and de-risking allowed the original subsurface scope to be reduced from a maximum of 10 injection wells to a range of 3 to 8 injection wells.
- Effectively utilise all the appraisal information into an updated understanding of the subsurface and develop a storage development plan for the subsurface, this will include the following elements:
  - Final well requirements – in terms of numbers, design, and location, and a well engineering strategy.
  - MMV planning – an adaptive MMV plan developed to ensure worker and public safety, protect the local environment and demonstrate the efficacy of CCS for greenhouse mitigation. This plan needs to cover both the baseline data gathering, operations and post-closure phase of the project
  - Project phasing – the proposed phase development of both injection and MMV elements of the project.
  - An integrated project plan including operations philosophy.
  - Risk and opportunity management plan.
  - HSSE plan.
- Sequestration Lease Application
  - Apply for and receive required pore space tenure from Alberta Energy
  - Develop a closure plan.
- Completion of basic engineering design.

Delivery of the following key documents which show the convergence of all of the work streams have converged to a single solution:

- The Storage Development Plan this is unusual as normally this document is a select phase requirement. It contains an overview of the subsurface, wells, pipeline and surface definition at this phase together with a description of how the project and subsequent operations will be managed. It is an evergreen document and will be updated at appropriate stages such as post drilling of the next phase of development wells and prior to start-up.

- Quest Basic Design Engineering Package(BDEP) [Ref 2.9]
- Both these documents need to stay within the confines of the Nov 2010 Regulatory Submissions as otherwise there is a risk of restarting the Regulatory Process.

These deliverables must contain a sufficient level of detail and reduced uncertainty and risk to enable the final investment decision (FID) to be made and gives the approval of funding and resources to start project construction and subsequent operations.

- **Execution**

The Execute phase is scheduled to take place between Q1 2012 and Q4 2014.

In this phase the integrated project plan will be executed to enable the capture, pipeline, wells and monitoring program to be ready for start-up end 2014 (first injection planned in January 2015). The Execute phase timeline and deliverables are outlined in more detail in section 2.7.

The overall strategy behind project delivery is to ensure construction of all critical elements of the fully integrated project are completed by Q4 2014, to facilitate an early start-up as soon as the HMU3 capture facility is commissioned.

To help reduce and predict cost the project has elected to pursue a Gen-3 modularization strategy to minimize the amount of on-site construction.

Subsurface appraisal and de-risking will continue by accelerating the next two injection wells to be drilled immediately after FID in the summer of 2012. This is expected to confirm sufficient injectivity for the project to achieve initial system injection rates but still allows for the drilling of two more injectors in 2013, should that be required, and have all injectors ready for CO_2 injection prior to start-up of the CO_2 pipeline.

A decision milestone on the number of injection wells is required by end September 2012 to feed a timely decision on a possible pipeline reduction by November 2012, but still maintain the opportunity to save significant development cost should three injection wells provide sufficient injectivity.

Early availability of injection well sites in 2012 is also required to support the acquisition of MMV base line data. Two years of base line data is required for shallow groundwater wells by acquiring continuous water electrical conductivity and pressure measurements in these wells to validate absence of impact on the hydrosphere. The drilling of deep observation wells is planned for end 2013 is not on the critical path. The final depth and design of these wells will be based on data obtained during drilling of the injection wells.

Additionally if necessary these wells can be deferred to create rig space for the drilling of more injection wells should this be required.

Well site activities are expected to be completed by end March 2014, in advance of the pipeline completion and HMU3 capture facility commissioning and avoid simultaneous operations during the tie-in of laterals to the pipeline.

- **Commissioning and Start-up**

  The objective behind the commissioning and start-up strategy is to ensure that the three performance tests as defined in the Funding agreement can be met before the end of 2015. Commercial Operations is the formal term that triggers the remuneration based on injected volumes of CO_2 and comprises a test on capacity, a test on efficiency and a test on integrated project reliability (CSU key steps to Commercial Operations).

  To support this objective all elements of the storage and pipeline scope should be ready for start-up by end 2014, to allow integrated system commissioning and start-up immediately after the HMU3 capture facility is commissioned (planned in January 2015). The tie-in of the HMU-1 and -2 in Q2-Q3 2015 will allow Quest to achieve full system capacity well before end 2015.

- **Operate Phase**

  The Operate Phase is scheduled to start in Q1 2015 and consists of an Injection phase during which data collection, monitoring measurement and verification (MMV) and risk assessments will be carried out at regular interval to assess how the site is performing against predicted models.

  The key drivers for the Operations phase are to ensure that the Quest Project delivers:

  - Facilities that can be safely operated with no harm to people
  - A reduction on the emission of greenhouse gasses for the Scotford Upgrader
  - Minimal impact on the production from Scotford and the mining operations that feed the Scotford Upgrader
  - Facilities that can be easily maintained and operated efficiently

  This will be carried out by a combination of Scotford Upgrader operations staff with technical support from the Well and Reservoir Surveillance (WRS) team in Calgary. This phase will be characterized by monitoring the capture, pipeline and storage facilities along with appropriate periodic updates of integrated reservoir models to establish storage conformance.

- **Closure Phase**

Full, sustained operations will continue for the life of the Scotford Upgrader, which is anticipated to be 25 years or greater. At this point CO2 injection will cease and closure activities begin. The injection wells and storage infrastructure will remain in place to continue the MMV processes as planned throughout the closure period, which Shell anticipates will occur over a period of 10 years.

Towards the end of the closure period, Shell will abandon the injection wells and reclaim the surface in accordance with the regulatory requirements in place at that time. Shell will work with the Crown to determine if select wells or MMV infrastructure would be needed by the Crown for continued monitoring.

Following the completion of site closure activities Shell will apply for a Site Closure Certificate in accordance with the prescribed criteria. At this point liability for the Quest storage site will be transferred to the Government of Alberta

- **Post Closure Phase**

  The post-closure period will begin with the issue of a Site Closure Certificate, which will transfer the long-term liability and any further post-closure activities from Shell to the Crown. Shell is committed to advising the Government of Alberta on its long term monitoring approach and sharing it's accrued knowledge and experience with the government prior to transfer. [Ref 2.10]

2.6. 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 CO2 capture infrastructure will begin in the third quarter of 2012 and continue to Q4 of 2014.
- Construction of the Main Pipeline is phased:
  - Construction of the portion of the pipeline within the Shell Scotford fenceline will occur in Q3 2012.
  - Setup and initiation of the horizontal directional drilling (HDD) of the North Saskatchewan River is now expected to start in Q3 2013.
  - Construction of the main pipeline is expected to begin in Q4 2013. This specifically addresses clearing and excavating work associated with the CO2 pipeline and laterals, exclusive of the watercourse crossings and connection to the Shell Scotford site. This work will still be conducted outside the activity period (RAP) of April 16 to July 31.

- Construction of the Lateral Pipelines is expected to begin in Q4 2013 (concurrent with pipeline construction), and could continue through 2014.
- Drilling of the injection wells will take place between Q3 2012 and the end of Q3 2014.
- MMV baselining activities are planned to commence in 2012 and will continue until start-up.

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 CO2 capture infrastructure end 2014.

For the schedule of the full integrated Quest CCS Project, see *Figure 2-6 Quest CCS Project Schedule*

2.6.1. CO2 Capture Infrastructure

The CO2 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 CO2 capture infrastructure to the Scotford Upgrader during the planned 2013, 2014 and 2015 turnarounds. The current anticipated schedule for key CO2 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 CO2 capture infrastructure
- Q2 2012 to Q3 2013 – detailed engineering and design
- Q3 2012 to Q4 2014 – construction of the CO2 capture infrastructure
- Q1 2015 to Q3 2015 – commissioning and start-up of the CO2 capture infrastructure
- Q4 2015 – full sustained operation

Decommissioning and abandonment of the Project could commence after 25 years and would require disassembly of the CO2 capture infrastructure.

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

2.6.2. CO_2 Pipeline

The current anticipated schedule for CO2 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
- Q3 2012 – pipeline construction within Scotford fenceline
- Q3 2013 – HDD of North Saskatchewan River
- Q4 2013 to Q2 2014 – construction of both the main and lateral pipelines
- Q1 2015 – commissioning and start-up of the pipeline
- Q4 2015 – full-capacity sustained operation

Decommissioning and abandonment will occur once the CO2 capture infrastructure has been shut down. The CO2 pipeline will be depressurized and abandoned in place.

2.6.3. 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
- Q3 2012 to Q3 2014 – drilling and completion of the injection wells
- Q1 2012 to Q4 2014 – acquisition of baseline MMV information
- Q1 2015 to Q3 2015 – commissioning and start-up of the Project
- Q4 2015 – full-capacity sustained operation

The injection wells would start the decommissioning process at the same time as the CO2 capture infrastructure. Once CO2 had stopped flowing to the wells, they would be closed in and monitored for a period before being abandoned through capping at the surface. As mentioned previously following the completion of site closure activities Shell will apply for a Site Closure Certificate in accordance with the prescribed criteria and the MMV and Closure Plan are designed to meet these criteria. At this point liability for the Quest storage site will be transferred to the Government of Alberta.

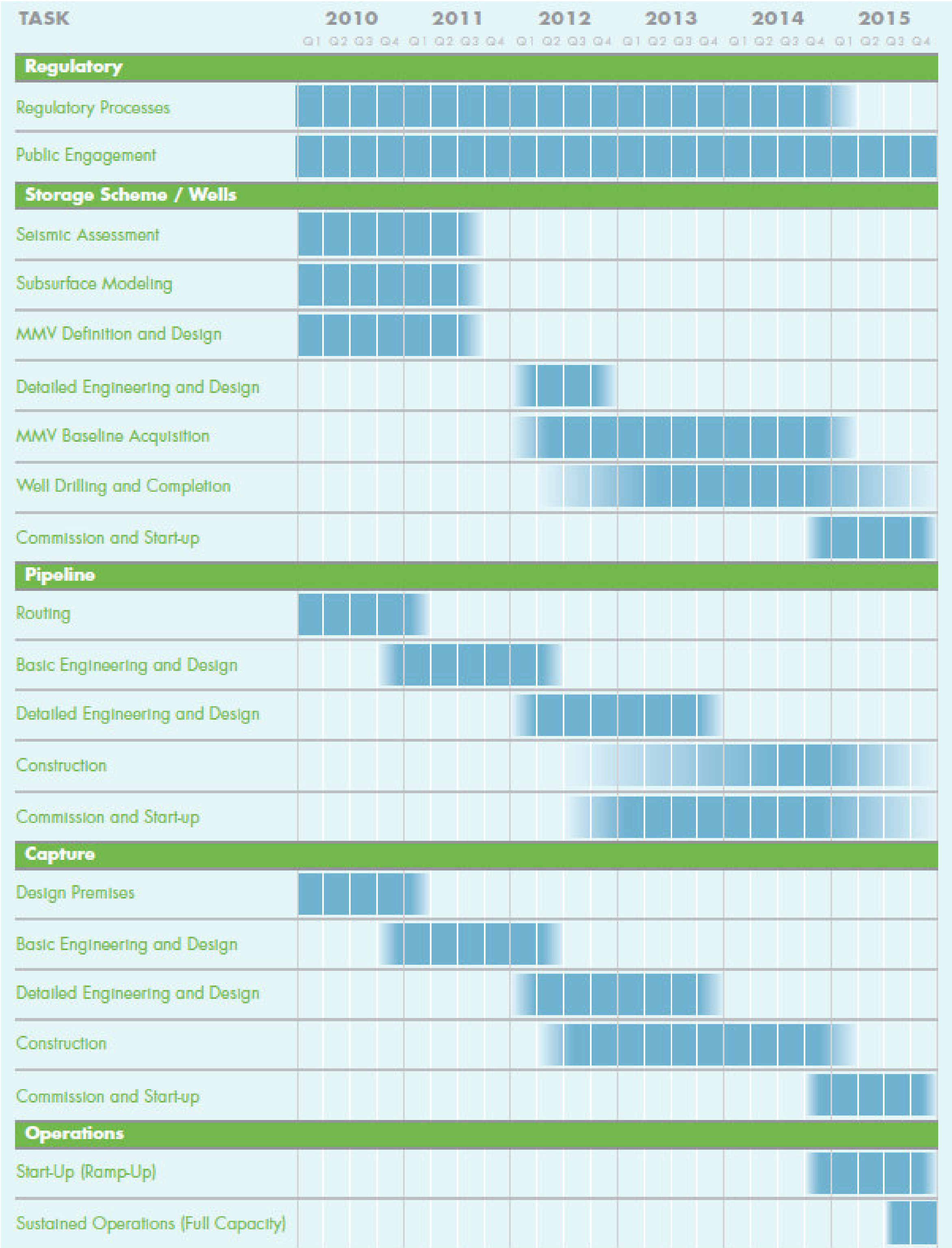


Figure 2-6 Quest CCS Project Schedule

2.7. Facilities Summary

The Capture facilities involve constructing:

- Modifications on the two existing HMUs and the new Expansion 1 HMU
- Replacement of catalyst in existing HMU 1& 2 Pressure Swing Absorption units and modification on PSA valve control logic.
- Three amine absorption units located at each of the HMUs
- A single common CO2 amine regeneration unit including a CO2 vent stack
- A CO2 compression unit
- A TEG dehydration unit
- Scotford Utilities and Offsites Integration
- Facilities to allow the injection of dedicated artificial tracers at the well site

For more detail on the surface facilities, see *Capture Site (Facilities)*

The pipeline facilities involve constructing:

- Phase 1: A 12″ main trunk pipeline with a total length of 64km (connecting wells 1-3).
- Phase 2: An optional 12″ pipeline extension of 11km (connecting wells 4-6)
- Phase 3: An optional 6″ pipeline extension of 6 km (connecting wells 7-8)
- 6″ laterals to all injection wells required
- Line Break Valve (LBV) sites at 12.7, 26.5, 32.3, 36.8, 50.7, 64, 75 and 81 km
- A pig launcher facility at the Capture Site
- Pig receiving and launching stations at the LBV site 32.3km, and receiving at LBV site 75km

For more detail on the pipeline facilities, see *Pipeline*

The storage facilities involve constructing:

- The drilling and completion of three to eight Injection wells with DTS
- A skid mounted module on each injection well site to provide control, measurement and communication for both injection and MMV requirements.
- The drilling and completion of a minimum of three deep observation wells
- The conversion of Redwater 3-4 to a deep BCS pressure monitoring well
- The drilling of three groundwater wells per injection well (although not all will be located on the well pads.
- Facilities to allow the injection at the well site
- A field trial of the line-of-sight CO2 gas flux monitoring technology in Q4 2011 with option to include this at each injection well site location
- For more detail on the storage facilities, see Storage Site and WELL SITE Selection

MMV will be supported by the following activities that require no dedicated facilities in the field:

- Time lapse seismic (Repeat 3D vertical seismic profile (VSP) surveys and time lapse surface seismic)
- Acquisition of Interferometric Synthetic Aperture Radar (InSAR) data
- Remote sensing designed to detect environmental change
- For more detail on the MMV facilities, see section *10 Measurement, Monitoring and Verification (MMV)*

2.8. Regulatory Management

Shell's mandate is to secure all necessary regulatory approvals for the Quest Project in a way that:

- Has all major approvals in place by FID, Q1 2012
- Promotes a thorough and transparent review of the potential environmental impacts of the project, given the public monies invested
- Obtains regulatory approval within project timelines or following the most efficient path; and,
- Follows the prescribed process, such that it can withstand a legal challenge

The Regulatory Strategy is based on the following assumptions:

- The receipt of funding from Natural Resources Canada (NRCAN) for the project will trigger a mandatory Canadian Environmental Assessment Act (CEAA) review of the Quest Project, including capture, pipeline and storage
- Although no aspect of the Quest Project triggered a mandatory provincial EIA, in order to allow a thorough and transparent review of the first commercial scale integrated CCS project in Alberta, Shell volunteered for an EIA. GOA focused the scope of the provincial EIA on the subsurface, or storage component of the project
- The Quest Project will receive public scrutiny; the decisions made by regulators in the process of issuing regulatory approvals, or the approvals themselves, will likely be subject to a legal challenge from NGOs or local stakeholders
- The public safety aspects of the storage component of the project will be the subject of most concern, because it is a new application of existing technology
- Some aspects of the regulatory process are retrofits: i.e. there are regulatory gaps that will require close collaboration with the regulators to manage the process steps, and requirements
- Bulletin 2010-22 was released by the ERCB in June 2010, clarifying some of the requirements for CCS projects

2.9. Stakeholder Engagement

The Quest team has been actively engaging with stakeholders since the fall of 2008. The primary immediate goals of the Quest CCS Stakeholder Engagement Strategy and Action Plan are:

- To inform stakeholders of Quest CCS Project plans, delivered in a timely and integrated fashion that conveys the potential impact of our proposed plans over the short and long term;
- Provide stakeholders with an opportunity to discuss concerns with and identify ways to address or mitigate stakeholder concerns relative to Quest CCS Project plans;
- Implement appropriate mitigation measures;
- Establish or build upon existing relationships;
- Identify opportunities to maximize benefits to stakeholders;
- Meet regulatory requirements for public consultation as per: ERCB Directive 56 (Energy Applications and Schedules), ERCB Directive 65 (Resources Applications for Conventional Oil and Gas Reservoirs) and Directive 71 (Emergency Preparedness and Response Requirements for the Petroleum Industry) , Provincial Environmental Assessment Report
- Meet CEAA (Canadian Environmental Assessment Agency) and Governmental Responsible Authorities requirements for public participation

Longer-term goals include building trust with key stakeholders. This will be achieved by:

- Ensure project initiatives do not set unacceptable precedents that may impair Shell's future business practices;
- Gain broad stakeholder support and leverage this support;
- Deliver on Shell's reputation as a responsible corporate citizen and industrial neighbour committed to the principles of sustainable development.

The Quest project will be operated by the Scotford operations team, and from very early on, the stakeholder engagement has been lead by key members of the Shell Scotford team. A stakeholder engagement plan was developed and implemented in 2010 and is updated annually. There is a combined Scotford/Quest Social Performance Plan that was developed in 2010. The execution of these plans in 2011 includes:

- Ongoing engagement for pipeline, seismic and wells consents;
- Quest newsletter for distribution to stakeholders in the storage area as well as pipeline and Scotford
- Advertorials (mini Quest news in local newspapers)
- World Cafe with community/key opinion leaders (April/May)
- Public open houses (September)
- Local content plan finalized
- County and City Council project updates (February/March and fall 2011)

- Scotford Community Meetings (April and November)
- Consultation with SOC filers/objectors
- ERP Planning, consultation and info package
- One on one meetings as required (ongoing)
- Documentation of all engagements (ongoing)

2.10. Risk Management Framework

Quest adheres to PS-20 - Project Risk Management in Capital Project and has an Integrated Risk & Opportunity Management Plan and Risk and Opportunity Register, covering both venture and project elements across the TECOP spectrum. The DNV software "EasyRisk" is used as a register tool and it is kept evergreen through the maturation process via regular update and progress meetings. A separate register is maintained for HSSE risks & actions from QRA, HEMP, HAZID and others. The storage Component uses the Italian Flags tool (TESLA) and methodology to assess uncertainty in terms of performance statements for CO2 storage (under capacity, containment, injectivity, MMV and wells). The TESLA statements are matched to the key storage risks in the risk register. The bowtie methodology has been used to develop a risk based MMV plan for storage. The storage risk assessment methodology and risk assessment has also been subjected to external scrutiny via a review by a panel of independent experts.

A Visual Risk Matrix is used as a communication tool to the DRB and other stakeholders for "High-level venture Risks & Opportunities".

A modified risk assessment matrix is used to reflect the unique aspects of a CCS project and the provisions of the funding agreement.*Figure 2-8 Quest Modified Risk Assessment Framework*

1) Cost/ Benefit in Operations is measured by cumulative impact during project Funding Period (first 10 years of operation)
2) Schedule delay to Final Investment Decision (between now and ~Q1 2012)
3) Schedule delay to Sustained Operations (incremental delay from FID to meeting contractual disposal requirement)
4) System Capacity refers to the cumulative impact on the combined Capture, PL and Sequestration capacity during project Funding Period (first 10 years of operation)
5) The Risk Assessment matrix is project specific, with the exception of HSE where a global RAM is applied

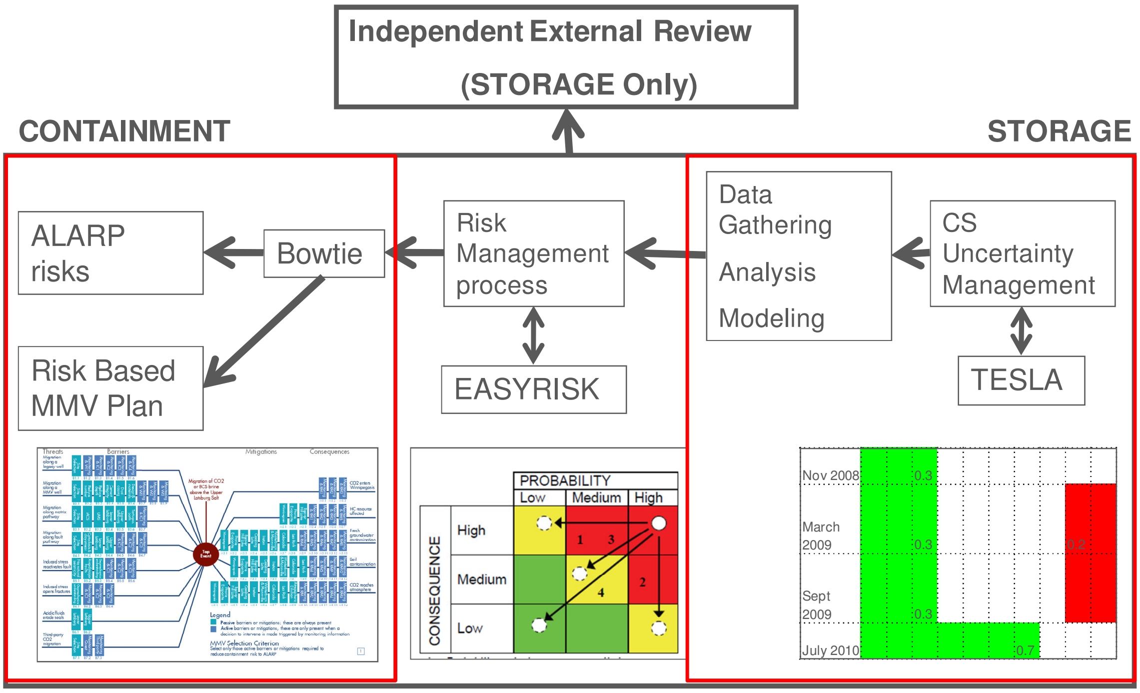


Figure 2-7 Quest Project Risk And Uncertainty Management

Last Update: April 22, 2010

Risk Category							PROBABILITY → 1 VLO	2 LO	3 MED	4 HI	5 VHI	Score Assessment	
Cost/Benefit in CDN $ [1]	Schedule delay to FID [2]	Schedule delay to SO [3]	System Capacity [4]	HSE [5]	Reputation		0-5% Occurs in almost no Projects (Extremely Unlikely)	5-20% Occurs in some Projects (Low but Not Impossible)	20-50% Occurs in Projects (Fairly Likely)	50-80% Occurs in most Projects (More Likely than Not)	80-100% Expected to Occur in Every Project (Almost Certain)	Score	Assessment
> 50 mln	> 6 mos	> 6 mos	>25% downtime	Refer to HSE RAM	International impact	IMPACT ↑	5	10	15	20	25	5	VHI
25-50 mln	3 - 6 mos	3 - 6 mos	20% - 25% downtime		National impact		4	8	12	16	20	4	HI
10-25 mln	1 - 3 mos	1 - 3 mos	15% - 20% downtime		Considerable (Regional) impact		3	6	9	12	15	3	MED
5-10 mln	0.5 - 1 mos	0.5 - 1 mos	10% - 15% downtime		Limited impact (public concern/ local media)		2	4	6	8	10	2	LO
< 5 mln	< 0.5 mos	< 0.5 mos	< 10% downtime		Slight impact (some public awareness)		1	2	3	4	5	1	VLO

IMPACT ↑

Figure 2-8 Quest Modified Risk Assessment Framework

2.11.Risks

The key project risks are highlighted in the attached visual (As of June 30th 2011). Details of the risks, their mitigation plan and assessments are given in Appendix 2

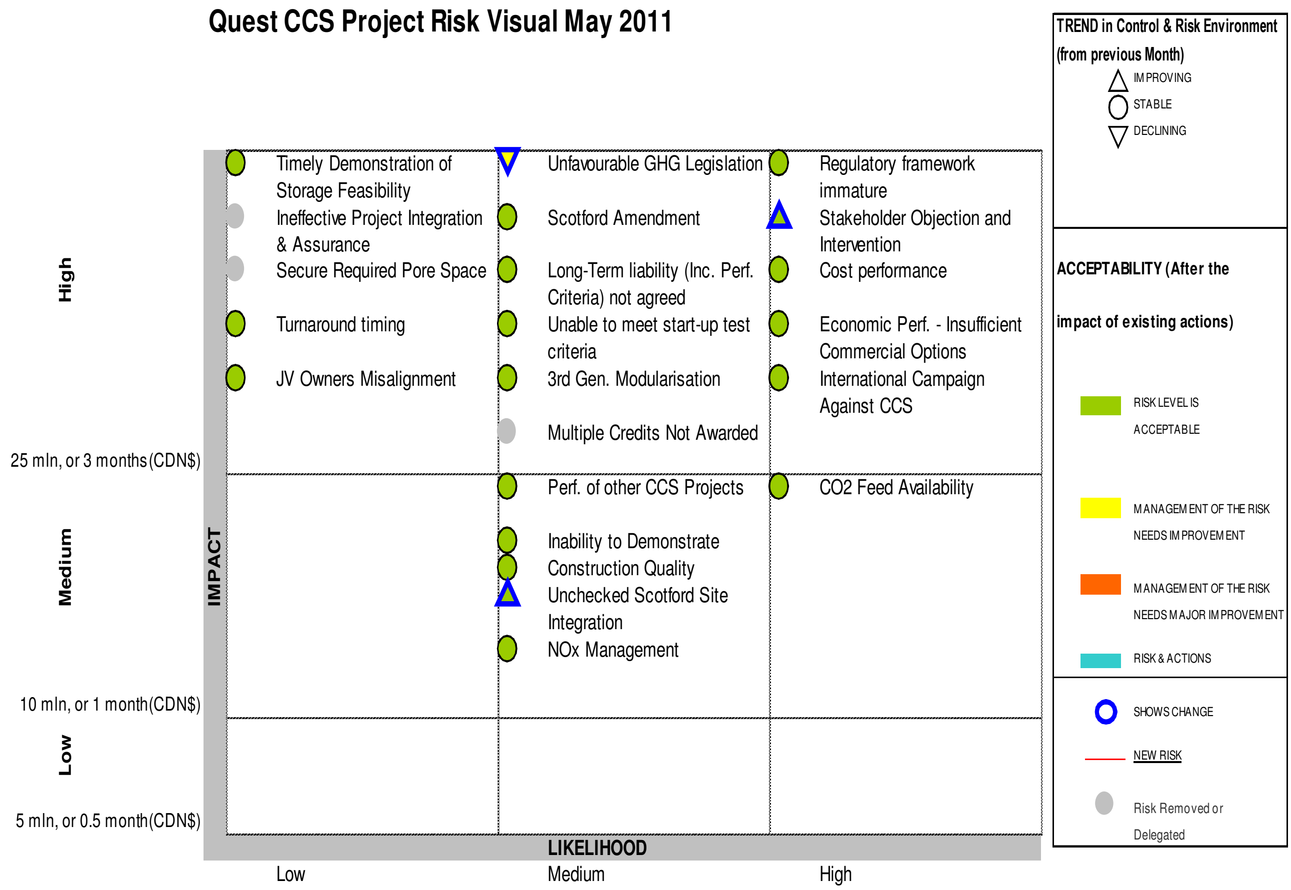


Figure 2-9 Quest CCS Project Risk Visual May 2011

2.12.Opportunities

The key project opportunities are highlighted in the attached visual (As of June 2011).

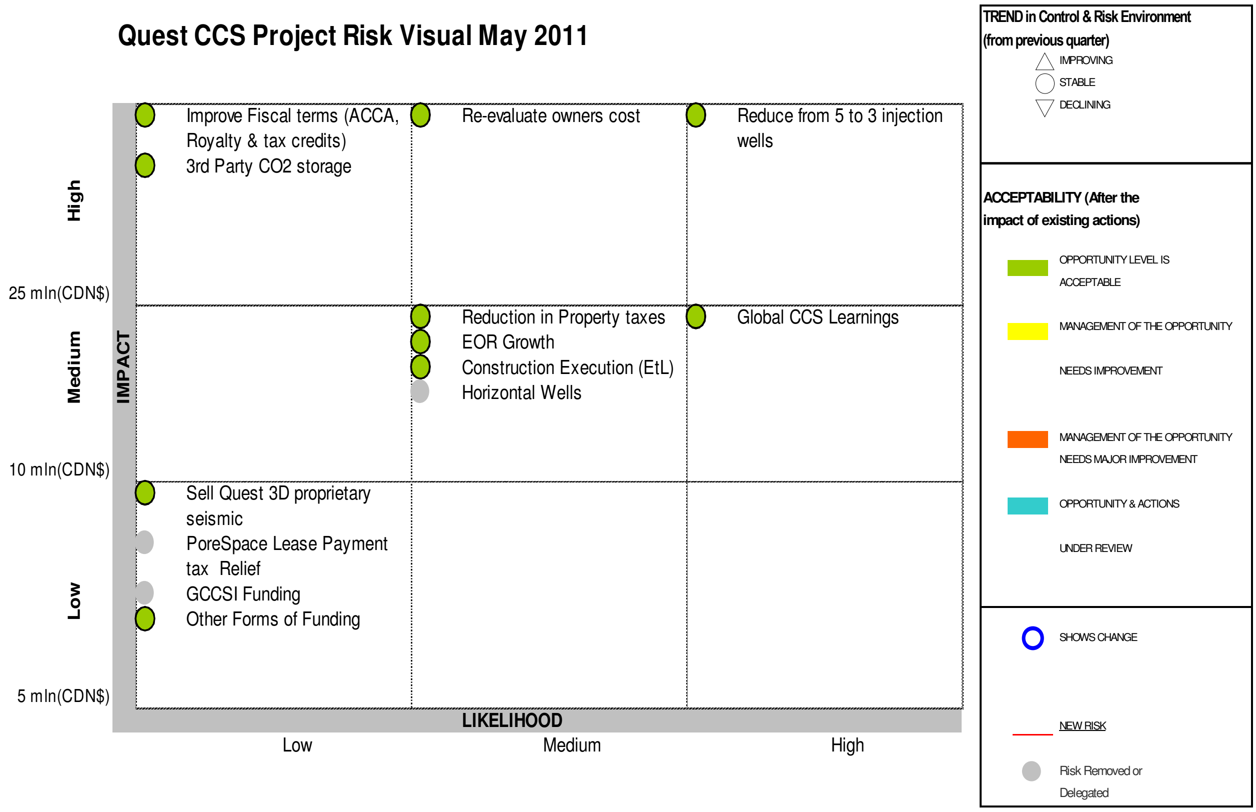


Figure 2-10 Quest CCS Project Risk Visual May 2011 (Opportunities)

2.13. Non-Technical Risk Management

The Quest CCS Project Non-Technical Risks extend from key overlying assumptions:

- There will be substantial public interest in the technology and the project
- There will be concerns fuelled by the novelty of the technology
- Some Non-Government Organizations (NGO's) will align against the project for the sole reason it is an enabler for continued oil sands operations and/or coal-fired power
- There may be requests for judicial review of key regulatory and/or environmental approvals
- The Open Houses and other public forums may be attended by NGO's or other groups intent on disrupting proceedings

The two main areas of non-technical risk for the Venture include *regulatory approvals* and *stakeholder engagement*. Key risks are managed in the EasyRisk Risk Register. Many of these risks apply to the Venture as a whole. Key risks include, or have included:

- Risks to schedule due to the immaturity of key aspects of the legislative and regulatory regime for carbon capture and storage in Alberta (e.g. subsurface storage, pore space resource) (R4354)

- General negative public stakeholder reaction to carbon capture and storage as a climate change solution or as an enabler of continued or expanded oil sands operations. Potential reputational risk (R4355)
- Negative perception of project by local stakeholders impacts regulatory activities and risks schedule (R4484)
- Failure to secure adequate pore space resource to permit commercial-scale operations (R4340)
- Amendment of existing Scotford approvals to include Quest capture facility risks expanding scope of regulatory process to include examination of existing facility and operations (R4566)
- Requirements for NOx management (R4037)

Plans to manage these key risks are covered in detail in a number of separate documents. These documents are:

- Quest Regulatory Strategy [Ref 2.11]
- Quest Stakeholder Engagement Plan [Ref 2.12]
- Quest Government Relations Plan [Ref 2.13]
- Quest Communications Plan [Ref 2.14]
- Quest Greenhouse Gas and Energy Impact Assessment [Ref 2.15]
- Quest Environmental Plan [Ref 2.16]
- Quest Exit Strategy [Ref 2.17]

As a result of management of these risks and completion of the identified and associated actions, Risk 4340 (i.e. Failure to secure adequate pore space) was closed in June 2011. Shell received Carbon Sequestration Leases sufficient for the full CO_2 Storage Scheme Area of Interest in May 2011via the Sequestration Lease Application.

2.14. Project Costs and Milestones

2.14.1. Costs

Table 2-1 Capital Cost Estimate for Quest Project as per Sept' 2011

CAPITAL COST ESTIMATE QUEST CCS "Rounded cost" OVERALL SUMMERY Cost Category	TOTAL CAD x 1,000
CO2 Capture Facilities	$410,300
CO2 Pipeline & Well Surface Facilities	$62,840
Wells "Base Case"	$63,470
SUB TOTAL EPCM EDM: JULY 2009	**$536,610**
Owners Cost	$141,880
Avg. Venture Contingency (30%)	$131,280
50/50 ESTIMATE TOTAL INSTALLED COST (TIC) - EDM JULY 2009	**$809,770**
Avg. Venture Escalation/ Inflation (13.8%)	$63,930
50/50 ESTIMATE TOTAL INSTALLED COST (TIC) - MOD Q1 2015	**$873,700**
FEED and OTHER EXPENSE COSTS TO FID DATE	$105,800

Note that above cost estimate for the Quest project is the define phase Shell Type 3 estimate available by September 2011.

2.14.2. Milestones

The project 50/50 schedule for Quest CCS is summarised in the following milestones:

Table 2-2 Quest Deterministic Schedule Milestones

Milestone	Timing
FEED Phase Complete	Q3 2011
EASR4/VAR4	Q3 2011
DG4	Q4 2011
ERCB Regulatory Hearing	Q4 2011
ERCB Regulatory Approval	Q1 2012
FID	Q1 2012
Substantial Det Eng Complete	Q1 2013
Compressor recieved	Q4 2013
Capture Fac. & HMU 3 Mech. Complete	Q4 2014
HMU 1 & 2 Mech. Complete	Q2 2015
First Injection	Q4 2014
Quest facility Start-Up	Q2 2015
Sustained Operation Achieved	Q4 2015
HMU 2 turn around	Spring 2013
HMU 3 turn around	Spring 2014
HMU 1 turn around	Spring 2015

3. HSSE AND SD

3.1. HSSE and SD Management

Shell believes that the management of Health, Safety, Security, Environment (HSSE) & Sustainable Development (SD) is integral to its business. Shell is committed to attaining "Goal Zero" by:

- Ensuring compliance with the HSSE SD Policies and Objectives, specifically the Shell Group HSE Golden Rules and the 12 Life Saving Rules
- Demonstrating that all hazards are adequately managed to As Low As Reasonably Practicable (ALARP).
- Achieving continuous improvement in HSSE SD performance.

Shell's commitment to contribute to SD is one of the Company's key business strategies and reflects the way we balance the environmental, social and economic aspects of our business. In practice, this means reducing impacts and delivering benefits – building our projects, running our facilities and managing our supply chain safely and in ways that reduce their negative environmental and social impacts and create positive benefits. In Shell, we are committed to:

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

Health, safety, environmental and security risks are recorded and tracked in the project Hazards & Effects Register. Risks such as Social performance risks and opportunities recognized during the Project are tracked in the Project Risk Register. The register is used as the primary control mechanism throughout the Project to demonstrate that each of the identified hazards and associated risks is either eliminated or managed to ALARP levels.

The Quest HSE Strategy and Plan has been developed to ensure the delivery of these aspects of the Quest CCS Project. The key principles and deliverables outlined in the Activity include:

- Leadership and Commitment
- Policies and Strategic Objectives
- Organization, Roles & Responsibilities, Resources, Standards and Documentation
- Hazards and Effects Management
- Planning and Procedures
- Implementation, Monitoring and Corrective Action

- Audits
- Management Review

An integral component of the HSE Strategy and Plan is the HSE Activities Plan that describes the activities required for each phase of the Project with resource commitments that will deliver the objectives and strategies specific to each phase. Full details are contained in the HSE Strategy and Plan and associated referenced documents [Ref 3.1]

The key HSE objectives for the Quest CCS Project are to:

- Design and construct a facility where the risks have been reduced to a level that is ALARP
- Reduce construction and operational risks by design measures
- Develop an HSE framework and plan for the construction, commissioning, operations and abandonment
- Reinforce HSE targets as defined in the Project HSE Strategy and Plan
- Maintain the quality, condition and integrity of the plant, equipment and tools
- Provide documentation to demonstrate the above, and to provide a link into the operations phase.

Evaluation criteria used for design decisions in the Quest Development Plan will be consistent with, and are based on the HSE and SD commitments described above.

3.2. Hazard and Risk Management

The Hazard and Effects Management Process (HEMP) is a structured and systematic analysis methodology involving the Identification, Assessment and Control of hazards and the Recovery from effects caused by a release of the hazards. All four components are essential for proper and effective hazard management.

The HEMP process will be applied throughout all project phases and Quest will comply with the requirements of [Ref 3.2] EP2005-0300-ST - HSE Hazards and Effects Management Process.

Several HSE tools and techniques have been utilized to support the HEMP process for technical HSE studies for the Quest Project. A schedule of HEMP-related activities and the appropriate timing of each activity is included in the Project HSE Activities Plan.

3.3. HSE in Projects

Quest will incorporate the requirements of Project Guide 01: *HSE Assurance in Capital Projects.* This guide identifies the mandatory and recommended Health, Safety, Environment and Sustainable Development (HSE & SD) activities for each project phase.

3.4. Emergency Response Planning

Shell has already amended its existing corporate-level Shell Canada Limited Core Emergency Response Plan to include CO_2 as a hazard, and to include pre-planned response actions that will aid in effective response and protect public safety in an emergency. The Shell Canada Limited Core Emergency Response Plan relates to prevention, preparedness, response, and mitigation of Project-related accidents or malfunctions and also addresses topics in addition to CO_2 such as:

- hazardous materials
- toxic substances
- unplanned spills, emissions or releases
- environmental emergencies
- freshwater pollution

Shell will also prepare a site-specific ERP for the Project. This plan will focus on preparedness and response to CO_2 emergencies, and will include the carbon capture and compression infrastructure, CO_2 pipeline, and CO_2 injection wells. The Project ERP will outline Shell's responsibilities and duties and coordination with government agencies in the unlikely event of a CO_2 emergency. The primary goal of both the Shell Core ERP and the site-specific ERPs is to provide an effective, comprehensive response to prevent injury or damage to site personnel, or the public, in an emergency.

Through modeling, Shell has determined a 450 m radius CO_2 emergency planning zone around the CO_2 pipeline and the CO_2 injection wells. Shell will consult on emergency response planning with all landowners and occupants within this distance. Shell will also notify all landowners and occupants within a 5 km radius of the Scotford facility about emergency planning for the Quest CCS Project [Ref 3.3]

3.5. Key HSE Issues

Based on the Design HSE Case and the HEMP reviews conducted to date, the key HSE challenges for the Project are as follows (together with the planned risk reduction/mitigation actions):

<u>CO_2 venting</u>
Little generic information is available regarding CO_2 venting. Therefore a number of ALARP workshops were conducted to determine the most suitable location, height and diameter based on CO_2 dispersion modelling.

<u>CO_2 vent materials of construction</u>
Materials of construction for the vent required investigation due to the extreme cooling effect of releasing CO_2 from a dense phase to atmosphere. An ALARP workshop decision was to use stainless steel for the vent.

<u>Personnel exposure</u>

A number of occupied buildings are in close proximity to the Quest facility and a CO_2 release could pose a health problem. A series of dispersion models were executed using various scenarios to ensure that building occupants were not exposed to levels of CO_2 which could be dangerous to health.

3.6. Assurance and Verification

The Project HSE Audit and Verification Plan will be updated at the start of every Project phase. The Project will employ three levels of HSE audits all designed to measure the effectiveness of the HSE programs and plans. These audits are categorized as follows:

- Level 1 External HSE Audits
- Level 2 Project HSE Audits
- Level 3 Technical HSE Audits and Inspections

All HSE & SD action items that are generated in these verification activities will be documented and progressed through the appropriate Risk and Commitment Register.

3.7. Greenhouse Gas Assessment

A report summarizing the expected greenhouse gas (GHG) emission reductions from the Quest carbon capture and storage project has been prepared by Blue Source Canada. This report summarizes the anticipated GHG emission reductions for the Quest Project according to three different GHG accounting scenarios: 1) Full Lifecycle Assessment; 2) Streamlined Lifecycle Assessment; and 3) Direct Emissions Assessment. Three cases were evaluated:

1. Power is sourced 80% from offsite cogeneration, and 20% from the grid.
2. Power is sourced 80% from onsite cogeneration, and 20% from the grid.
3. Power is sourced 100% from the grid.

Steam for all three cases is sourced 100% from onsite cogeneration. Emissions reductions for the three cases are summarized in the table below:

Table 3-1 GHG Emissions

	Type of GHG Emissions	Case 1 (tCO_{2e}/year)	Case 2 (tCO_{2e}/year)	Case 3 (tCO_{2e}/year)
(A)	Gross Captured CO_2	1,080,000	1,080,000	1,080,000
(B)	Direct Emissions	54,581	107,549	54,581
(C)	Indirect Emissions	83,703	30,735	153,677
(D)	Upstream/Downstream Emissions	19,377	19,377	24,813
(E)	Construction and Decommissioning Emissions	4,893	4,893	4,893
	Net Annual GHG Reductions			
	Direct Emissions Assessment [(A)-(B)]	**1,025,419**	**972,451**	**1,025,419**
	Streamlined Lifecycle Assessment [(A)-(B)-(C)]	**941,716**	**941,716**	**871,742**
	Full Lifecycle Assessment [(A)-(B)-(C)-(D)-(E)]	**917,446**	**917,446**	**842,036**

In all cases, the Quest Project is expected to deliver net GHG reductions of greater than 840,000 tonnes of CO_2-equivalent emissions per year in Alberta after accounting for all significant indirect sources of emissions at all stages of the project.

For further details see [Ref 3.4].

3.8. Provincial and Federal Regulations

3.8.1. Environmental Setting[1]

The Project is located in the Boreal Forest and Parkland Natural Regions of Alberta (Natural Regions Committee 2006). The Boreal forest region includes two subregions: central mixedwood and dry mixedwood.

The central mixedwood subregion covers the northern-most portion of the project area (generally, north of the North Saskatchewan River). The dry mixedwood covers some of the southern portion of the project area (generally, south of the North Saskatchewan River).

Available information from the Natural Regions Committee (2006) and industrial applications for the region (Total 2007; Shell Canada 2005) indicate that the majority of the project area is dominated by agriculture and urban and industrial development, particularly the central parkland subregion. As a result, much of the region is disturbed and highly fragmented. Non-native and invasive species are common.

White spruce–mixed evergreen deciduous woodlands are the most common upland land unit, while marshes—particularly ephemeral to seasonal marshes—are the most common wetland land unit. Treed swamps, treed fens and graminoid fens also occur but are generally not

[1] Information taken from the CEAA Project Description filed December 2009

common. Riparian land units are the least common land unit, but are found along the banks of the North Saskatchewan River and other creeks in the area.

The proposed pipeline route crosses Class C watercourses, the largest being the North Saskatchewan River. In Alberta, Class C watercourses are defined as "moderate sensitivity; habitat areas are sensitive enough to be potentially damaged by unconfined or unrestricted activities within a water body; broadly distributed habitats supporting local fish species populations." (AENV 2001).

There are also a number of environmentally significant areas (ESAs) potentially affected by the pipeline, all in the vicinity of the North Saskatchewan River valley (Government of Alberta 2009), including:

- ESA 690 – intact riparian habitat and large natural areas in vicinity of Astotin and Beaverhill creeks and North Bruderheim natural areas
- ESA 320 – habitat for focal species (e.g., ferruginous hawk) and large natural areas associated with North Saskatchewan River basin
- ESA 455 – presence of large natural areas supporting non-vascular plants; associated with North Saskatchewan River

3.8.1.1. Aquatics

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.
- The North Saskatchewan River supports fish habitat, but no unique or critical habitat components for any species occurs in the area of the planned crossing.
- 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.

3.8.1.2. Soils and Terrain

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.

3.8.1.3. Vegetation and Wetland

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.

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

3.8.1.4. Wildlife and Wildlife Habitat

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 are located in a highly fragmented landscape dominated by cultivated fields. The general environmental context for the region is disturbed lands with low biodiversity.

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.

3.8.1.5. Historical resources

A baseline field survey was conducted and targeted areas with high potential for historical, archaeological or paleontological features. Eight pre-contact 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 paleontological resources (such as dinosaur fossil localities) were identified at four locations near the Project.

3.8.1.6. 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.

3.8.2. Environmental Assessment

In October 2009, the Quest Project signed a letter of intent with the federal government to receive funding under the Clean Energy Fund. NRCAN's decision to provide funding is subject to a federal *Canadian Environmental Assessment Act* (CEAA) Environmental Assessment (EA). The process has been initiated with the submission of the QUEST Project Description (PD) on December 15 2009. The PD was reviewed by the federal agencies to determine the scope of the project, the level of EA required (Screening Level or a Panel Review), and the agencies to be included as Responsible Authorities (RA).

The additional need to follow the federal environmental process has lead to the Project re-assessing its regulatory strategy and environmental assessment approach. The new strategy is outlined in the Quest Regulatory Strategy [Ref 2.11]. The Regulatory Strategy combines the applications for the pipeline, wells and capture facility into a bundled application and supporting environmental assessment. The project has submitted the CEAA Project Description to CEAA in December 2009. The Federal government has advised that a screening level EA will be required. The EA will be subject to a harmonised process between both levels of government, with one submission. The TOR was made available for public comment in August 2010. The project is considered a Major project, and the federal MPMO is tracking all federal agencies participation.

The EA was submitted on November 30, 2010 at the same time as the regulatory applications bundle.

3.8.3. Environmental Applications

The Quest project is regulated by a number of jurisdiction and regulatory bodies. Over the past number of years several applications and permits have been applied for and received. The following two tables include the most current list of environmental applications and permits.

Table 3-2 Provincial Environment Applications

Document	Regulation/Authority	Date Filed
Environmental Impact Assessment [Ref 2.8] 07-0-HE-0702-0001	EPEA/AENV	November 30, 2010
PLA Applications all 5 named water course crossings	Public Lands Act/ ASRD	March 31, 2011
Water Act Code of Practice Notification for pipeline crossing and temporary vehicle crossings	Water Act/ AENV	March 15, 2011
Conservation and Reclamation Plan for Pipeline	EPEA/AENV	November 30, 2010
Environmental Review	EPEA/AENV	November 30, 2010
Historical Resource Assessment	Alberta Culture and Community Spirit/	February 2011
Conservation and Reclamation Plan for the wells	Although not required until the abandonment phase of the project, this was prepared according to EPEA. Additionally it was submitted as part of the EA.	November 2010
Environmental Protection Plan	Support document to the C&R Plan for the pipeline	November 2010
Paleontological Assessment	Alberta Culture and Community Spirit/	February 2011
Terms of Reference	EPEA/AENV	November 2010
Closure Plan [Ref 2.10]	Carbon Sequestration Tenure Act	May 2011

Table 3-3 Federal Environmental Applications

Document	Regulation/Authority	Date Filed
Environmental Assessment 07-0-HE-0702-0001	CEAA/NRCAN	November 30, 2010
Application (all 5 named water course crossings)	Transport Canada Navigable Waters Act	
Project Description	CEAA	December 2009
Scoping Document	CEAA	
Terms of Reference	CEAA	

The Environmental Assessment (EA) is organized into 18 sections plus supporting appendices. The first four sections provide an introduction to the Project and the methods used in the assessment, summarize the environmental consultation program and describe the route selection process and final proposed Project description. Sections 5 through Section 15 provide an assessment of the environmental effects of the Project by biophysical or socio-economic component.

- Air Quality (Section 5)
- Sound (Section 6)
- Geology and Groundwater Resources (Section 7)
- Aquatic Resources (Section 8)
- Soils and Terrain (Section 9)
- Vegetation and Wetlands (Section 10)
- Wildlife and Wildlife Habitat (Section 11)
- Historical Resources (Section 12)
- Land Use (Section 13)
- Public Health and Safety (Section 14)
- Socio-Economics (Section 15)

In addition:

- Section 16 discusses the effects of the environment on the Project
- Section 17 discusses accidents, malfunctions and unplanned events
- Section 18 discusses follow-up and monitoring

The water course crossings are subject to many of the permits. The following is a list of all of the water course crossings within the Quest project that were considered for application *Table 3-4 All Quest Project Water Crossings Considered for Application*. Those that are named have been subject to many of the applications (i.e. PLA, Navigable Water, etc). In all cases Shell has committed to following the DFO operational statements to cross these. Should this decision change applications will need to be revisited. Additionally Shell has committed to crossing the North Saskatchewan River using a HDD technique.

Table 3-4 All Quest Project Water Crossings Considered for Application

Crossing ID	Location	Watercourse Name	Watercourse Class
1	NE-13-056-21W4	Astotin Creek	C
2	NW-20-056-20W4	Beaver Hill Creek	C
3	SE-27-056-20W4	Unnamed tributary to NSR 1	D[1]
4	SE-11-057-20W4	Unnamed tributary to NSR 2	C
5	NW-18-57-19W4	Unnamed tributary to NSR 3	D[1]
6	NW-36-57-20W4	North Saskatchewan River	C
7	SE-13-56-21W4	Drainage 1	D[1]
8	NW-15-56-20W4	Unnamed tributary to NSR 4	D[1]
9	SW-11-058-20W4	Unnamed tributary to NSR 5	C
10	NW-14-058-20W4	Unnamed tributary to Namepi Creek	C
11	NW-23-058-20W4	Unnamed tributary to Namepi Creek	C
12	SW-26-058-20W4	Namepi Creek	C
13	NE-34-058-20W4	Drainage 2	C
14	SE-32-059-20W4	Unnamed intermittent waterbody	D[1]
15	NE-15-060-21W4	Namepi Creek	C
16	NW-15-060-21W4	Drainage 4	D[1]
17	SE-21-060-21W4	Drainage 5	D[1]
18	NE-21-060-21W4	Drainage 6	D[1]

[1] *These drainages had no defined bed or banks and were therefore assigned a class of D*

All of the applications can be accessed on livelink at the following link:
https://knowledge.shell.ca/livelink/livelink.exe?func=ll&objId=31359084&objAction=browse&sort=name

A commitment list has been extracted from all filed documents. This list is being managed by all Projects using the CTSE system. It will be updated and expanded as the Project files additional material to support the regulatory process.

https://knowledge.shell.ca/livelink/livelink.exe?func=ll&objId=53428622&objAction=browse&sort=name

A Quest specific, Environmental Plan [Ref 2.16] has been developed and will continue to evolve through all stages of the project. This plan covers, water management, biodiversity, noise mitigation, air emissions, waste management etc. It has a controlled collections number of HE5880.

3.9. Major Provincial Regulatory Approvals

An early decision was taken to bundle all major regulatory applications for all aspects of the project. This includes the Capture Scotford Amendment, pipeline D56 approval, the D65/D51 storage scheme application and the D56 injection well applications, together with their associated environmental approvals that must be issued in tandem with the ERCB approvals (each examined in turn below).

Bundling all applications is possible and might be preferred by the ERCB for simplicity. It is also consistent with the federal process (no project splitting) and promotes the thoroughness of review of the project because all aspects are subject to a public review.

Careful consideration was given to the risks associated with bundling, which are opening up the Scotford approvals to a public hearing, opening up the full project to public review, and a risk to the project schedule. Overall, the benefits of bundling outweigh the risks.

All major provincial regulatory applications were submitted on November 30, 2010.

3.9.1. Capture Application

CO_2 will be captured from three hydrogen manufacturing units at the Scotford Upgrader. An absorber vessel will use an amine solvent to capture the CO_2 from the process stream. CO_2 will be compressed and dehydrated into a dense fluid for safe pipeline transport. The CO_2 fluid will be transported by pipeline to the storage site.

The key regulatory approvals required for the CO_2 capture facilities at the Scotford Upgrader are:

- Amendment to the Scotford Upgrader ERCB Approval No. 8522 (as amended) pursuant to Section 13 of the Oil Sands Conservation Act for approval to construct and operate the CO2 capture infrastructure (issued by the ERCB)
- Amendment to the Scotford Upgrader Alberta Environment (AENV) 10 year operating license Approval No. 49587-01-00 (as amended) pursuant to Division 2, Part 2 of the

Alberta Environmental Protection and Enhancement Act (EPEA) for approval to construct, operate and reclaim the CO2 capture infrastructure Issued by Alberta Environment)

These formed a single integrated Amendment application, submitted to the ERCB and AENV on November 30, 2010 [Ref 2.7].

3.9.2. Pipeline Application

CO_2 captured at the Scotford Upgrader will be transported by pipeline to injection locations within 100km from Scotford. The pipeline will follow existing rights-of-way wherever possible. Safety, landowner input, environmental, and technical issues will all be taken into consideration to determine final route. Consultation on the pipeline route began in January 2010.

Regulatory requirements for the construction and operation of CO_2 pipelines in Alberta fall under ERCB and AENV, and are known and understood. The key provincial regulatory approvals required for the CO_2 pipeline from the Scotford facility to the commercial well site are:

- Applications for the construction and operation of the main CO2 pipeline pursuant to Part 4 of the Pipeline Act (Pipeline construction and operating license issued by the Energy Resources Conservation Board pursuant to Directive 56)
- Conservation and Reclamation (C&R) approval for Class 1 pipeline pursuant to the EPEA and issued by Alberta Environment

Although the ERCB has advised that a D71 Emergency Response Plan (ERP) is not required, Shell has committed to preparing a D71 compliant ERP as part of the planning process.

The two applications were submitted in November 30, 2010.

3.9.2.1. CO_2 Pipeline

The CO_2 pipeline approvals include:

- Applications for the construction and operation of the main CO2 pipeline pursuant to Part 4 of the Pipeline Act
- Conservation and Reclamation (C&R) Plan for a Class I pipeline (see Volume 1, Appendix E), as specified under the Alberta EPEA Activities Designation Regulation.

Distribution pipelines to carry CO_2 from the main pipeline to the injector wellheads will require amendment of the pipeline approvals.

3.9.2.2. Environmental Assessment

Government of Canada funding of the Quest CCS Project triggers the need for an EA under Section 5(1)(b) of the *Canadian Environmental Assessment Act* (*CEAA*). This will address all three components of the Quest CCS Project. *The Canada–Alberta Agreement on Environmental Assessment Cooperation* (the Agreement) guides federal–provincial cooperation for the environmental assessment of projects subject to both the *CEAA* and the Alberta *EPEA*. A cooperative EA that is consistent with the Agreement, meaning a single EA, was prepared by Shell to meet the requirements of both the *CEAA* and the *EPEA*.

3.9.3. Storage Application

The regulatory requirements for the construction and operation of a commercial CO_2 storage program in Alberta are currently under review. The ERCB issued Bulletin 2010-22 in June 2010, and advised that Directive 65, Section 4.2, the acid gas provisions, were applicable to the disposal of CO2. Shell remains of the opinion that D65 does not yet adequately address the requirements for a large scale commercial disposal operation.

The CCS Amendment Act (2010) and the Carbon Sequestration Tenure Regulation (April 2011) laid out the requirement for a monitoring, measurement and verification (MMV) Plan to accompany a Carbon Sequestration Lease Application to be submitted to the ADOE. It is anticipated that the ERCB will also eventually require the submission of an MMV plan as part of its D65 Scheme approval, and that the AENV will require the submission of an MMV plan, in order to ensure protection of groundwater.

The key regulatory approvals required for the commercial well program are then anticipated to be:

- Approval of individual injector wells (Alberta Energy Resources Conservation Board, Directive 56- Energy Development Applications and Schedules)
- Approval for conceptual disposal scheme (Alberta Energy Resources Conservation Board, Directive 65- Resources Applications for Conventional Oil and Gas Reservoirs)- to be included as part of the D65 application for the specific disposal well (above)
- D51 reporting on the specifics of the development and completion of the storage well (Alberta Energy Resources Conservation Board, Directive 51- Injection and Disposal Wells)

The conceptual scheme concept is one that is still being actively discussed with the ERCB and ADOE.

The CO_2 storage approvals submitted in November 2010 include:

- Application to the ERCB for a Class III disposal scheme pursuant to Part 6, Sections 11, 12 and 39 of the Oil and Gas Conservation Act, and Part 15 of the Oil and Gas Conservation Regulations
- An environmental impact assessment (EIA) as directed by the Government of Alberta and under the Alberta EPEA. The EIA focused on the storage component of the Quest CCS Project, and was submitted to the Government of Alberta concurrently with Shell's applications to the ERCB.

3.10.Regulatory Schedule

The following are key dates for the development and follow-up on Quest regulatory applications:

Table 3-5 Regulatory Schedule Key Dates

Date	Deliverable
November 2010	All seven regulatory applications and EA were submitted to the federal and provincial governments as part of the regulatory bundle strategy
March through July 2011	Response to Information Requests (IR's) and deficiency letters: The federal RA's and the Provincial regulatory agencies will have reviewed the applications and then requested additional information. Shell will respond to the IR's, and in some cases, new information will be submitted to respond to the questions. This would be an opportunity to submit a further definition of the Directive 65 scheme, being careful to balance the clarification versus the determination by the ERCB or CEAA or AENV that we have changed the project description and need to re-submit.
June 2011	D65 Update – An update to the D65 scheme application was submitted to the ERCB, including revision to the number of wells (3-8), and identification of the locations
September 2011 (estimate)	Assuming a Hearing in November 2011, all final evidence will be filed with the ERCB for consideration at the Hearing. This would be the last opportunity to enter information onto the record. Again, the balance between clarification/response and the introduction of substantial new information that would restart the clock is essential.
November 2011	Hearing
March 1, 2012	ERCB Board Penal report, release from CEAA.

4. CAPTURE SITE (FACILITIES)

4.1. Concept Selection

This section describes the process technologies reviewed in selecting the best process facilities for the Quest CCS Project. Several factors were taken into consideration to justify the processes selected: minimizing capital cost, operating cost, plot space and safety requirements, as well as impact on the current operation of the HMU's while capturing and sequestering CO_2.

The CO_2 removal facility should have minimal impact on the Hydrogen Manufacturing Plants, while it is in operation or has a shutdown.

The main facilities for CO_2 removal and sequestering are:

- CO2 removal process
- CO2 compression
- CO2 dehydration process

For more details see the following references [Ref 4.1, 4.2, 4.3, 4.4, 4.5, 4.6].

4.1.1. CO_2 Removal Process

For CO_2 removal, the types of processes considered were chemical reaction processes, physical absorption processes, cryogenic processes and solid bed processes:

- For the chemical reaction processes ADIP-X and MDEA were considered.
- For physical absorption process Selexol was considered.
- For the cryogenic physical absorption process the SGSI Methanol process was considered.
- For the solid bed processing MTR membranes and Linde PSA were considered.

These alternatives were studied for both upstream and downstream of the Pressure Swing Adsorption (PSA) Units of the HMU's. The most favourable location was determined to be upstream of the PSA's where the pressure is the highest, thus less compression is required. Capital Cost, Operating Cost, operability, space constraints, and safety issues were reviewed for each alternative.

ADIP-X is the selected CO_2 removal process. The closest competing CO_2 removal process is MDEA. MDEA was not selected because of higher Capital Cost.

For more information please see [[Ref 4.7] 07-0-PX-0580-0001 Technology Selection Report – Capture].

4.1.2. CO_2 Compressor

As part of the project, a CO_2 compressor compresses stripped CO_2 from the amine process into a pipeline for transport to the injection sites. Based on the composition of the CO_2 gas, flowrate, inlet conditions, and discharge pressure, a study was done by SGSI to determine the most appropriate compression technology for the project.

It was recommended by Shell TA1 rotating equipment (Chris Gilmour) to use an integrally-geared centrifugal compressor for the QUEST project, because of its advantages in efficiency, capital and installed cost, and flexibility over a traditional single-shaft centrifugal compressor arrangement (in this case, this would look like a motor in the middle of the train driving at both ends a speed increasing gear-box driving a two-section centrifugal compressor). Discussions with key suppliers (MAN Turbo, Siemens, GE) show that they also agree that, considering currently available technologies, the integrally-geared centrifugal compressor is clearly superior to the single-shaft arrangement.

[[Ref 4.8] to Quest document number 07-1-MR-8226-0001 Integrally Geared Centrifugal CO_2 Compressor Qualification]

4.1.3. CO_2 Dehydration Process

TEG and a solid bed desiccant mol sieve were considered to remove water to prevent hydrate and corrosion issues. Mol sieve is attractive for very low water specifications.

However, for the Quest Project the water specification is at the normal TEG dehydration range, so TEG Capital Cost and Operating Cost are lower than for mol sieve. Thus, TEG is selected as the CO_2 dehydration process.

4.2. Quest Process Units

The capture process can be summarised in three main process units described below and summarised in *Figure 4-1 Quest Overview Process Flow Diagram*. For a full description of the Capture process and its technical details [[Ref 4.1] the Basic Design Package document number 07-1-AA-7704-0002.]

<u>The HMU's</u>

Shell Canada currently operates three Hydrogen Manufacturing Units (HMU1, HMU2 and HMU3) at the Scotford Upgrader. The production of hydrogen represents a significant source of CO_2 generated in the Upgrader, which is released from the reformer furnace stack. A significant portion of the CO_2 generated is a by-product of the steam reforming and shift conversion reactions. The CO_2 in the syngas stream from the HT-Shift Converter is cooled at high pressure, which presents an energy efficient source for CO_2 recovery, due to its high partial pressure

<u>Amine Absorption</u>

An amine absorption and regeneration system is used to capture and recover about 80% of the total CO_2 from the three HMU PSA feed gas streams. The absorption process used is the ADIP-X process, which is an accelerated MDEA-based process licensed by Shell Global Solutions International (SGSI). The CO_2 Rich Amine streams from each individual Absorber is combined and stripped in the Amine Stripper t and recover CO_2 with about 95% purity.

Compression

The recovered CO_2 is compressed in an 8-stage centrifugal Integral Geared (IG) compressor with an electric motor drive. The CO_2 is compressed and dehydrated, and will enter the pipeline at a maximum of 14,000 kPag. This dense phase CO_2 is transported by pipeline from the Scotford Upgrader to the injection locations which are located up to 85 kilometres from the Upgrader.

4.2.1. CO_2 Capture and Amine Regeneration

CO_2 Capture is comprised of a CO_2 Absorption section and an Amine Regeneration section.

The CO_2 Absorption section consists of three CO_2 absorber systems that are located within the Base Plant (HMU 1 and HMU 2) and Expansion 1 (HMU 3) areas. Each absorber system consists of an amine absorber, water wash vessel, water wash pumps and circulating water cooler. The HMU 1 and HMU 2 absorber systems are identical. These absorber systems use lean amine to remove approximately 82% of the CO_2 from the raw hydrogen feed gas stream, which is taken from upstream of the PSA units. The absorption process used is the ADIP-X process, which is an MDEA-based process licensed by Shell Global Solutions Inc. (SGSI) that uses piperazine as an accelerant to enhance CO_2 absorption at high pressure and low temperature.

The Amine Regeneration section removes the CO_2 from rich amine produced in the CO_2 Absorption section by applying heat in a low pressure Amine Stripper. Stripped vapour is sent overhead and cooled to remove water, and the CO_2 rich vapour is then sent to the CO_2 Compression area for compression and further removal of water (see section 4.2.2). Lean amine from the bottom of the Amine Stripper is cooled before being sent back to the Amine Absorbers.

4.2.2. Compressor and Dehydration Unit

The purified CO_2 stream from the Stripper Reflux Drum is compressed to a supercritical state, at 14,000 kPag with an electric driven integrally geared (IG) centrifugal compressor. Water is removed from the CO_2 in interstage knockout drums and a triethylene glycol (TEG) based Dehydration Unit. The supercritical CO_2 from the compressor discharge is cooled and transported via pipeline off-site to the sequestration wells

The design of the CO_2 Compressor is based on compressing the CO_2 recovered from the CO_2 Capture and Amine Regeneration sections from 42 kPag to 14,000 kPag. The discharge pressure is set in accordance with the pipeline and well requirements, and is at the functional operating limits of the 900# carbon steel pipeline (at 60°C). An 8-stage IG centrifugal compression system is required, and the power requirement is 17 MW for the compressor.

The design of the Dehydration Unit is to reduce the presence of water in the CO_2 to 6 lb / MMSCF in winter and 4 lb / MMSCF in summer using TEG. The water-rich TEG is regenerated using a combination of reboiler with IP Steam as the heating medium and nitrogen stripping to restore the TEG concentration to above 99 wt%. The dehydration unit is installed after the 6th stage of compression to take advantage of the natural water saturation properties of CO_2 at around 5000 kPaa.

4.2.3. Revamp of Hydrogen Manufacturing Units

As part of the Quest project, raw hydrogen gas from the process condensate separators is sent to the new amine absorbers (refer to Section 16 of the Quest BDP) which are designed to remove 80% of the CO_2 from the stream. The treated gas is returned to the existing HMUs upstream of the PSA Units.

As a result of CO_2 capture, the composition of the PSA tail gas, which is used as fuel in the Steam Reformer furnace, changes significantly. The CO_2 in the tail gas acts as a heat carrier in the convection section of the reformer. Flue gas recirculation (FGR) is implemented to reduce the NOX formation in the reformer furnace with the fuel composition.

[[Ref 4.9] Quest Basic Design Package doc. 07-1-AA-7704-002] for the major changes to HMU 1 and 2 as a result of implementing CO_2 capture.

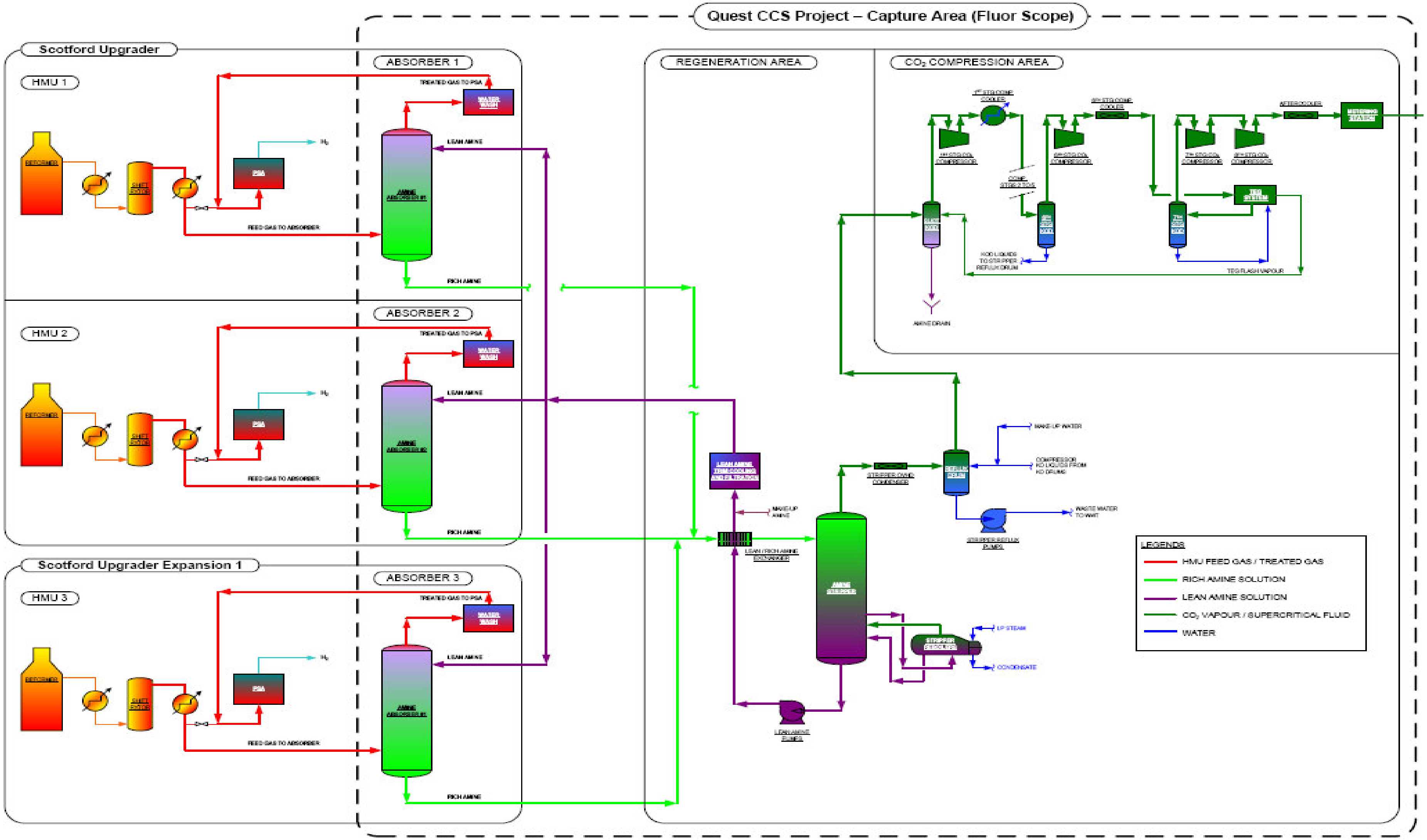


Figure 4-1 Quest Overview Process Flow Diagram

4.2.4. CO2 specifications

The specifications for the captured and compressed supercritical CO2 for normal operating conditions are identified in *Table 4-1 CO2 Specifications* and *Table 4-2 CO2 Properties*.

Table 4-1 CO2 Specifications

CO2 Concentration	95 vol% (minimum)
H2O Content	6 lb / MMSCF (maximum, Note 1)
Hydrocarbon Content	5 vol% (maximum)

It should be noted that water content specification is up to a maximum of 6 lb per MMSCF during the summer months and to a maximum of 4 lb per MMSCF during the required periods of the remaining seasons with ambient temperatures up to approximately 20°C.

Table 4-2 CO2 Properties

CO2 to Pipeline	
Temperature, °C	43
Pressure, kPag	13900
Molar Rate, kmol/h	3400.3
Mass Rate, kg/h	148568
Molecular Weight	43.69
Enthalpy, kJ/kg	-9144.6
Mole Fraction Vapour	0.00
Total Stream Composition, mol%	
H2O	0.01 %
CO2	99.2 %
CO	0.02 %
N2	0.00 %
H2	0.68 %
CH4	0.09 %

4.3. Scotford Brownfield Impact

The Quest CCS Project interfaces with the Upgrader Base Plant and Expansion to feed the CO_2 Capture facilities and provide new utility connections to new equipment items. The following interface points have been identified:

Base Plant HMUs (HMU 1/2 and common facilities):

- Raw H2 Gas Supply / Return
- Cooling Water for Absorber 1/2 Circulating Water Coolers
- Flare connection for pressure control vents and relief valves
- Utility Air
- Instrument Air
- Nitrogen
- Utility Water
- LP Steam for Utility Stations
- Power
- DCS and SIS integration
- Fire Water

Expansion HMU3 and common facilities:

- Raw H2 Gas Supply / Return
- Cooling Water for Absorber 3 Circulating Water and Make-up Water Coolers
- Condensate for make-up water
- Waste Water to DO system
- Flare connection for pressure control vents and relief valves
- Utility Air
- Instrument Air
- Nitrogen
- Utility Water
- LP Steam for Utility Stations
- Power
- DCS and SIS integration
- Fire Water
- Utility (Unit 251) tie-ins
- Cooling Water Supply / Return from/to Cogen
- Recovered Clean Condensate
- Demin Water Return to the Deaerator
- Underground Utilities (Units 258 / 282)
- Fire Water to Quest Greenfield area
- Potable Water
- Base Plant Piperack (Unit 285)

- LP Steam from Cogen
- Demin Water Supply to Quest for heat recovery
- Waste Water
- Low Temperature HP Steam
- Instrument Air for Quest Greenfield area
- Utility Air
- Nitrogen
- Utility Water
- Power

The lean and rich amine systems require additional interfaces between the Base Plant and Expansion units. The amine flow control and antifoam systems require instrumentation interfaces between the Base Plant Foxboro control system and Honeywell Experion control system.

4.4. Scotford Utility and Offsites

Upgrader utilities will be extended to provide services to the Quest greenfield and brownfield units. No new utility facilities are required within the Upgrader's Utility plant, Raw Water plant, Waste Water Treatment plant or Cooling Tower to satisfy Quest's utility demands. Design of piping systems to the Quest unit are used to satisfy the expansion of services that Quest requires. Increases in utility system throughputs to meet Quest's requirements are deemed to be within the operational windows of each of the respective utilities.

5. STORAGE SITE AND WELL SITE SELECTION

5.1. Storage Site Selection

This Section documents the process used to identify and select a suitable storage site for CO_2 injection starting Q4 2014. A Site Screening process resulted in a preferred Area of Interest (AOI) that was initially selected for further appraisal and studies in 2010 and 2011 by submitting an exploration tenure request with the regulator on 16 December 2009. The subsequent process of site characterization comprised a period of intensive data acquisition, resulting in Storage Site endorsement prior to submitting the regulatory applications on 30 November 2010 and culminating in the award of a sequestration lease by Alberta Energy on 27 May 2011.

5.1.1. An Historic overview

An Authorisation For Expenditure for three Quest appraisal wells to support the regional geological assessment of the Basal Cambrian Sands (BCS) between Scotford and Smoky Lake was approved in September 2008. By Q1 2009 the first 2 wells (Redwater 11-32 and Redwater 3-4) had been drilled within 16 km of the Scotford complex and had shown adequate promise in terms of CO_2 capacity, injectivity and containment within the BCS saline aquifer. These well results underpinned the Full Project Proposal (FPP) submission for CCS funding to the Alberta Department of Energy (ADOE) at the end of March 2009 and called into question the need to drill the 3rd exploration well at the most distant Smoky Lake location. The 3rd well opportunity was therefore re-defined as a final storage site appraisal well and "keeper injector" for final development. This called for the well to be located near the centre of an area that could be used for a commercially scaled CO_2 storage scheme. This re-assessment triggered the following observations in Q2 2009:

- An integrated assessment of a robust site for final CO2 storage development needed to be made before proceeding with further appraisal activities.
- Future appraisal design criteria needed to be aligned with CO2 storage development plans.
- Landowner engagement would need to move from a relatively benign request to drill, run logs, take cores and run short tests at individual appraisal well locations to a more detailed discussion with a wider group of landowners around a commercial storage scheme lasting ~25 years in their neighbourhood.
- The lack of exploration pore space tenure rights (for which there was no legislation at the time) could pose a risk to Project timing and impede appraisal and development activities.
- To meet injection start-up in Q1 2015 (and meet the requirement for approved regulatory applications by FID Q1 2012) landowner engagement on the proposed pipeline route to the preferred site had to start by January 2010.

All these factors highlighted the importance and urgency of a site selection decision, to allow an early start of 3D seismic acquisition and appraisal drilling and completion of the subsurface evaluation with a CCS field development plan in place before FID early 2012.

The justification for the selection of the BCS as the base case storage container is provided in Chapter 5 of the FPP [Ref. 2.1] and EP Report EP-2009-3064 and summarised below:

- The geological properties of the BCS are generally considered to deteriorate in terms of injectivity and capacity to the southwest of Scotford as depths into the basin increase towards the Alberta Industrial Heartland and Edmonton.
- The area towards the southwest is also less attractive in terms of containment because the Lotsberg salt seals are thin or not present. This has been confirmed by the regional evaluation of vintage wells.
- Furthermore, surface access is considered restricted due to the considerable infrastructure of the Industrial Heartland area and the populated area of the city of Edmonton.

The focus area for the site selection evaluation therefore concentrated on three locations to the north of Scotford Upgrader.

5.1.2. Site Selection Criteria

Site selection for Quest was mainly based on data, analyses and modelling of the two Quest CO_2 appraisal wells with supplemental data from vintage wells, seismic and study reports. Site selection criteria for CCS projects are still in the process of being developed by CCS authorities at international, national and provincial levels. One example is shown in *Table 5-1 Assessment of the BCS for Safety and Security Of CO2 Storage* on the next page.

Table 5-1 Assessment of the BCS for Safety and Security Of CO2 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 (Middle Cambrian Shale [MCS], Lower Lotsberg and Upper Lotsberg Salts) continuous over entire CO_2 storage AOI. Salt aquicludes thicken up dip to 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 or 3D 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	>2000 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 AOI 20-500 mD
	17	Caprock thickness	<10 m	≥10 m	Three caprocks MCS 21-75 m L. Lotsberg Salt 9-41 m U. Lotsberg Salt 53-94 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.[Ref 5.2]

Three alternative areas *Figure 5-1Site Selection Alternatives Reviewed (Red Outline is preferred AOI)* were selected for further review based on this preliminary screening:

- Site A - North of the North Saskatchewan River
- Site B - South of the river some 16 km ESE from Scotford
- Site C - North of river directly WNW from Scotford

At this period in time, given the overall scale of investment required for the capture and transport element of the Quest project a seven well injection scenario was used as a “screening” development scheme (sized to the boundaries of the brine pressure front after 25 years of injection) in order to provide a robust risk mitigation to low injectivity and capacity that may only become finally apparent after 2 to 5 years of sustained injection. The notional outer pressure contour (deltaP of 890 kPa) after 25 years of injection in a Homogeneous (Gen-2) low reservoir property model with seven injection wells was used to establish a rough approximation of the lease size requested in the exploration pore space tenure submission *Figure 5-1Site Selection Alternatives Reviewed (Red Outline is preferred AOI).*

Generally, a favourable screening of the three alternative storage sites north of Scotford is obtained when assessed against emerging selection criteria provided in *Table 5-1 Assessment of the BCS for Safety and Security Of CO2 Storage.*

Other areas around Scotford, beyond the three alternative sites, were screened out, as they are significantly poorer with respect to two “critical criteria”:

1) The area southwest of Scotford has significantly less coverage by regional geological seals and is located beneath industrial and residential infrastructure hindering MMV potential.
2) Sites further to the east and north of these three sites are also screened out because they are considered to be significantly more expensive to develop due to rapidly increasing pipeline cost for more distant storage sites without clear incremental advantages in the seven site selection criteria.

To select one of the three selected alternative storage sites, there was agreement that the relevant data and information needed in order to make an informed assessment generally include the following selection criteria:

1) Capacity
2) Injectivity
3) Containment
4) Monitoring Measurement and Verification (MMV)
5) Pore Space Access
6) Cost
7) Growth

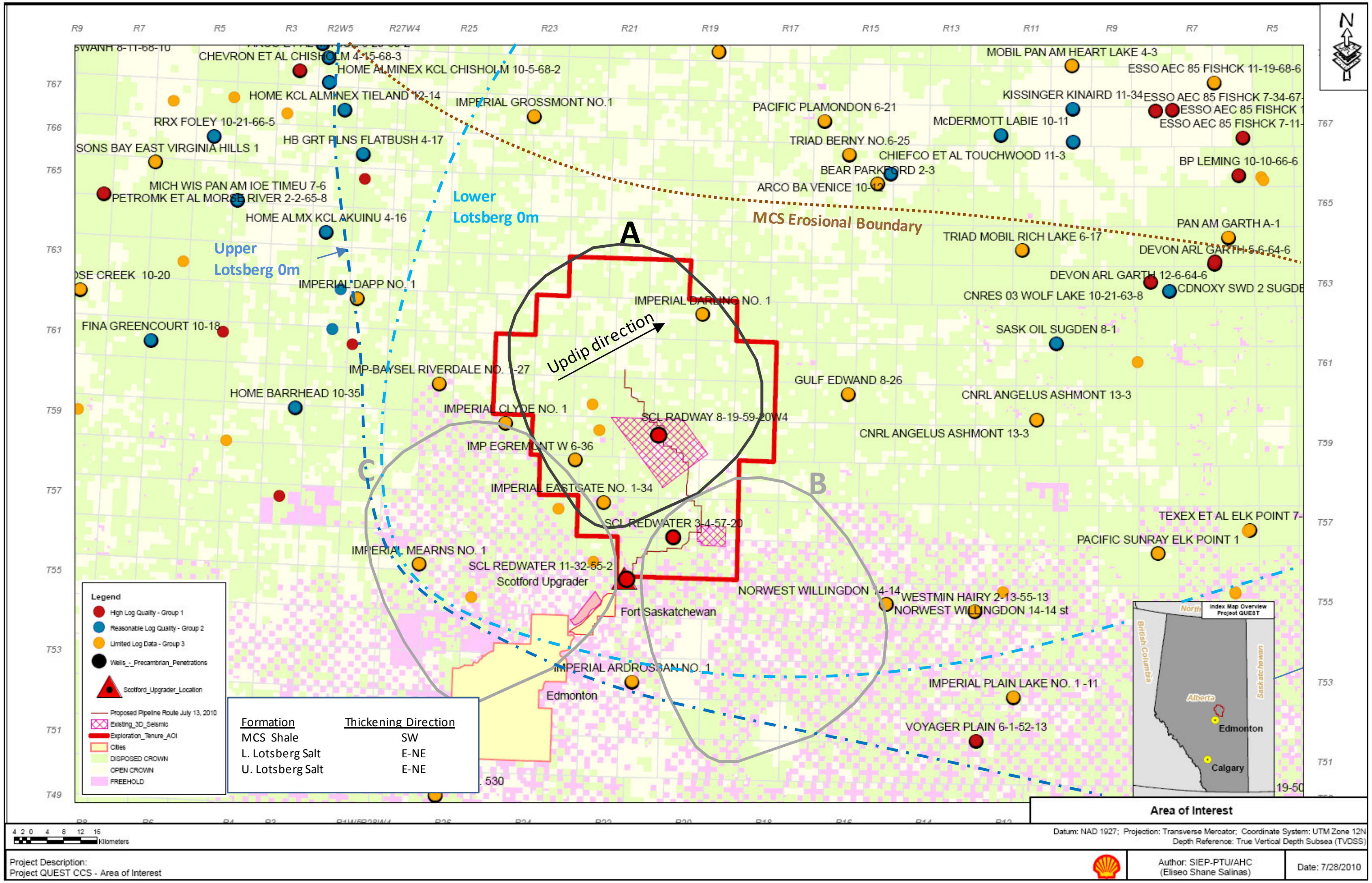


Figure 5-1Site Selection Alternatives Reviewed (Red Outline is preferred AOI)

Based on current information, the criteria found to be the most distinctive differentiators between the three sites were containment, pore space access, cost and growth *Table 5-2 Comparison of the Three Alternative Sites for Long-Term CO2 Storage in the BCS near to the Scotford Complex.*

1. Containment

   Refers to the change in the quality of the seals between the three different locations and is predominantly an effect of the Devonian unconformity eroding the primary seal the MCS towards the NE. This creates the accommodation space for the development of the secondary and ultimate seals the Lower and Upper Lotsberg Salts.

2. Pore Space Access

   It should be recognised that at the time of the identification of the AOI and the original exploration pore space tenure submission there was no mechanism to grant saline aquifer pore space tenure. This position was rectified in March 2011 with the passing of The Carbon Sequestration Tenure Act. However, it was recognised that a key screening criteria to simplify the exploration pore space tenure submission was to ensure the percentage of freehold vs. crown subsurface rights was negligible.

3. Growth

   Recognising the GoA desires to have 139 Mtpa CCS by 2050 meant that the ability to grow the scheme in the success case was an additional screening criteria.

Of the three sites, "Alternative A" in *Figure 5-1Site Selection Alternatives Reviewed (Red Outline is preferred AOI)* was ranked the highest mainly due to its superior attributes in terms of containment, pore space access and growth. The selection of this site formed the basis for the Exploration pore space tenure submission that was submitted to the ADOE in December 2009 and formed the focus area for significant appraisal and pipeline field activities in 2010. After March 2011 the Exploration Pore Space Tenure submission was superseded by the Sequestration Lease Application that was approved in May 2011.

For additional details on the basis for selecting the current storage site is referred to the site selection report [Ref. 5.3].

Table 5-2 Comparison of the Three Alternative Sites for Long-Term CO2 Storage in the BCS near to the Scotford Complex.

Criteria	Alternative A	Alternative B	Alternative C	Assessment
Capacity	Shallowest location with potential improving properties (e.g. porosity) providing marginal additional benefit	Marginally larger gross thickness of the BCS		The 3 Alternatives screen on this criteria. There is no key differentiating information in order to rank Alternatives.
Injectivity	Structuration is considered to be oriented SW to NE. This potentially groups Alternatives A & C in terms of susceptibility of the BCS to faulting	BCS faulting observed in small 3D seismic survey. Distant permeability barrier to the east (from well and aeromagnetic data) and potential risk to long-term sustained injectivity.		The 3 Alternatives screen on the 7-well low case model as a mitigation to sustained commercial-scale injectivity. Spatial information for characterization of flow units is sparse & currently insufficient to clearly differentiate them.
Containment	Upper & Lower Lotsberg salt seals are extensive over the plume extent for this alternative. These units also thicken to the NE. Fewer updip penetrations in the BCS than Alternative C	Less spatial coverage from the Lotsberg salts that Alternative A	Highest number of updip vintage BCS penetrations, smallest contiguous unpenetrated BCS pore space.	Alternative A is most advantageous on this key criteria given the low number of well penetrations and superior spatial coverage of the Lotsberg salt seals.
Monitoring Measurement and Verification	Minimum surface infrastructure	Some surface infrastructure.	Considerable surface infrastructure & located over the mature Redwater Oil field. Potential synergies using shallower abandoned wells for monitoring & future 3D seismic for both the oil field & BCS development.	The MMV plan is generic at this phase of study. All sites screen on the basis of current information.
Pore Space Access	Dominated by Crown (disposed and undisposed) subsurface rights with minimal Freehold.	Dominated be Freehold subsurface rights for the Cambrian which could complicate/slow development	As Alternative B and HARP has plans to drill to the BCS in this area.	Alternative A is most advantageous on this criteria.
Cost	Furthest from Scotford, higher cost than other Alternatives on pipeline length etc.	More local to Scotford - potential for lower development costs	More local to Scotford - potential for lower development costs	Alternatives B & C are most advantageous on this criteria.
Growth	In favourable position for extension towards Alternative B, further development to the northeast and northwest.	In favourable position for extension towards Alternative A and further development to the northeast.	The least favourable position for BCS growth as a pipeline towards Alternatives A and B would also be required.	Significant Growth Potential for the shallower Redwater Reef at Alternative C. Technical feasibility, ownership & timing reduce the ranking of this opportunity.

5.1.3. Appraisal and Site Characterisation workflow

The programme of subsurface appraisal activities for the Quest Carbon Capture and Storage (CCS) Project was designed to reduce key uncertainties about the performance of the Basal Cambrian Sand (BCS) Storage Complex to acceptable levels prior to the Final Investment Decision for the project in 2012. The area of interest for subsurface appraisal is limited to the region defined in the Exploration Pore Space Tenure submission to Alberta Energy on December 16, 2009.

There were several principal interim goals that needed to be supported by the Quest Subsurface Appraisal Strategy [Ref. 2.3] on the way to FID:

(i) to inform the regulatory submissions
(ii) to inform the Storage Development Plan
(iii) to inform the Measurement, Monitoring and Verification Plan (MMV)

The appraisal programme was designed to provide subsurface information sufficient to evaluate the viability of the BCS geological storage complex for development as a commercial CCS project. In particular, information was required to evaluate the three prime requirements for geological storage of CO2:

- Containment
- Injectivity
- Capacity

Several key decisions about the Quest CCS development concept were required prior to finalising this Storage Development Plan (SDP). The appraisal programme was required to assist in reducing subsurface risks associated with the following decisions to acceptable levels:

- Injection Pressure
- Number of Injection Wells
- MMV Strategy

The selected appraisal methods provided a balance between:

- Areal coverage and resolution
- Time versus key deliverables

A high-level timeline showing the timing of the various activities relative to project level decisions and supporting modelling generations can be seen in *Figure 5-2 Subsurface Timeline Overview to VAR4*

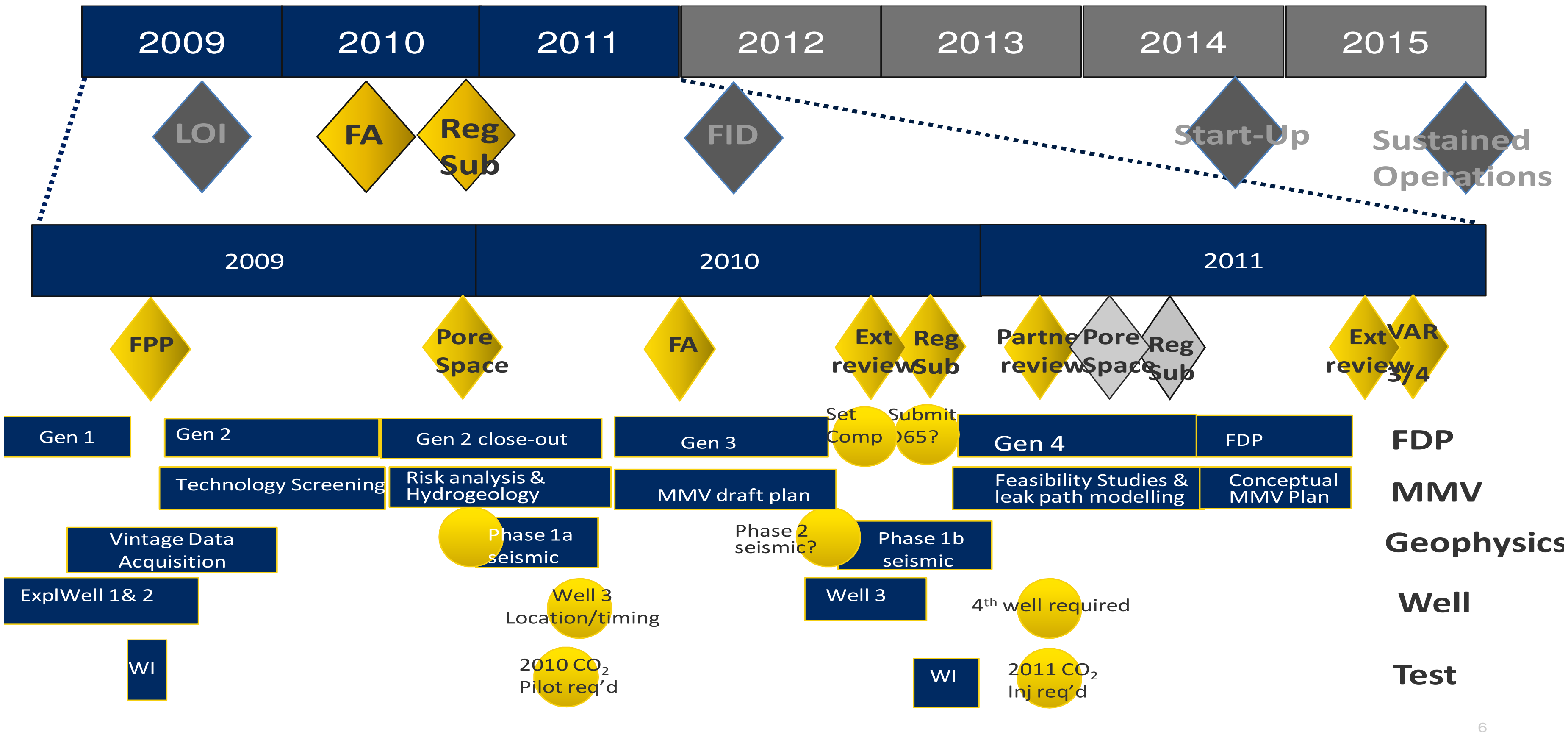


Figure 5-2 Subsurface Timeline Overview to VAR4

Table 5-3 Appraisal Programme Summary

Appraisal Method	Coverage	Resolution	Relative Cost
High-Resolution Aeromagnetic Survey	8,600 km^2	Lateral resolution: *c.* 2-3 km Vertical resolution: *c.* 1 km	Low
2D Seismic Surveys	55 lines spanning 3,700 km^2	Lateral resolution: *c.* 25 m Vertical resolution: *c.* 20 m	Medium
3D Seismic Surveys	415 km^2	Lateral resolution: *c.* 25 m Vertical resolution: *c.* 10 m	High
Appraisal Wells	Three locations	Lateral resolution: *None* Vertical resolution: *c.* 1 m	High
Injection Tests	<1 km^2	None	High

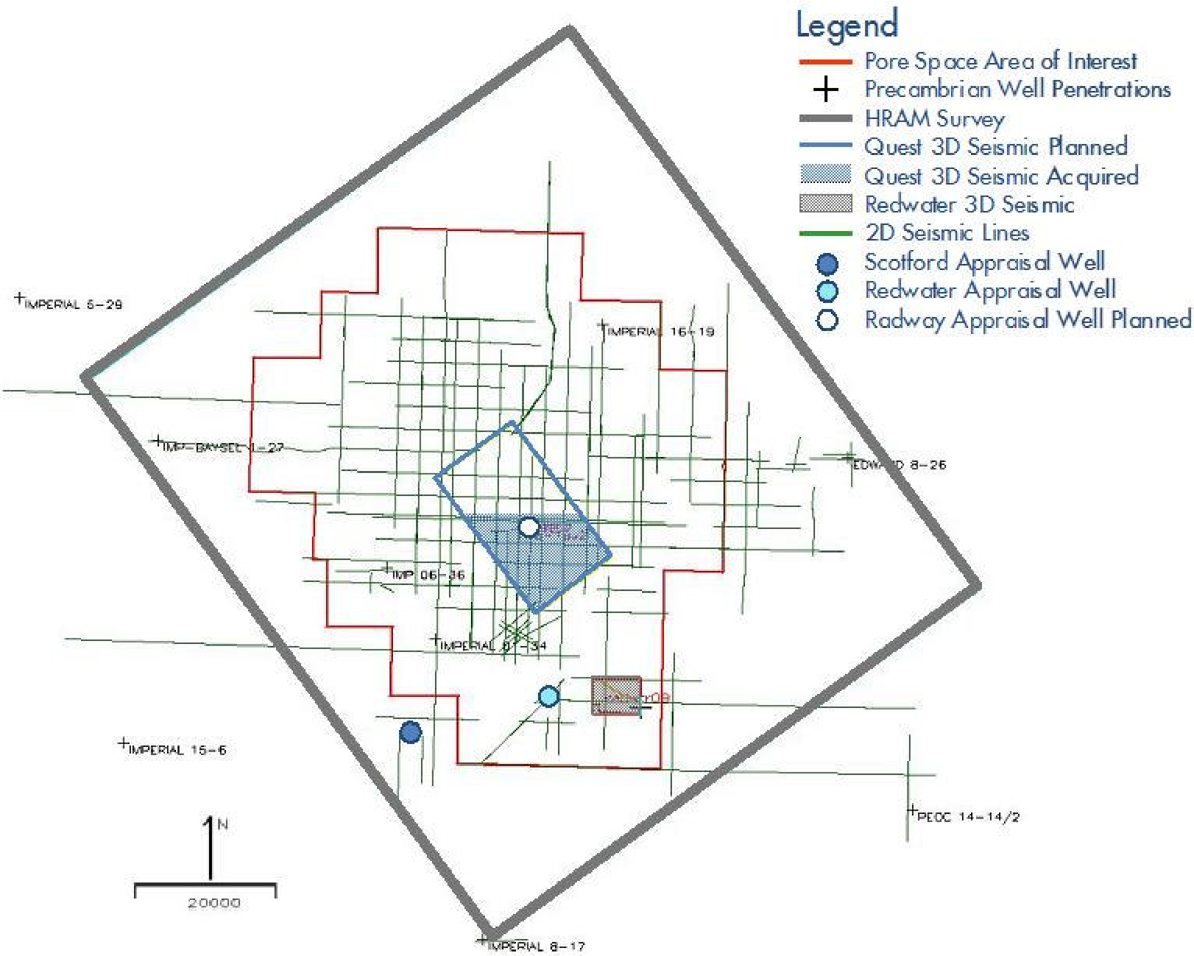


Figure 5-3 Summary of the Appraisal Programme Undertaken to Characterise the Pore Space AOI.

5.1.3.1. High-Resolution Aeromagnetic Survey

A high-resolution airborne magnetic survey (HRAM) yields a map of local variations in the strength of the Earth's magnetic field. These anomalies occur due to differences in the magnetic properties of geological formations. With care, and the appropriate geological conditions, a fraction of these magnetic anomalies may be isolated and potentially used to indicate variations in the depth to the Precambrian basement that directly underlies the BCS. In this manner, basement faults would be interpretable as individual discrete lineaments if the change in basement depth across the fault exceeds 50-75 m (detection sensitivity) and the distance to the next detectable basement fault exceeds 2-3 km (resolution). Any collection of unresolved basement faults will appear as an indivisible magnetic anomaly and therefore cannot be distinguished from a single larger fault occupying the same position.

Basement structures, such as faults, are not the only source of magnetic anomaly and so their interpretation may be error-prone. Independent information about basement depth and fault lines derived from well and seismic data provides an opportunity to validate the interpretation of magnetic anomalies and mitigate this risk.

If HRAM yields reliable information about basement structure, this will:

- influence subsurface models that forecast storage performance, and
- identify prospective regions for acquiring any additional 3D seismic.

Due to the limitations described, there is only a moderate likelihood of this method providing reliable information. However, the relatively low cost, the ability to reject unreliable information and the value of mapping basement faults over the entire area of interest justified the inclusion of HRAM.

5.1.3.2. 2D Seismic Surveys

Acquisition of existing trade data and in-house reprocessing provides a cost-effective grid of 55 seismic lines spanning the entire area of interest with a typical line spacing of 3-5 km. The quality of these trade data is variable but overall is sufficient to provide information about the:

- lateral extent of the seals across the area of interest,
- presence of any significant faults that might compromise the containment of fluids,
- absence of BCS due to basement faulting that might constitute a barrier to fluid flow, and
- location of prospective regions for acquiring any additional 3D seismic.

Due to their lack of contiguous areal coverage, these 2D seismic data leave significant uncertainties about the character of smaller-scale geological structures such as small faults and channels that may adversely affect the performance of an injector.

5.1.3.3. 3D Seismic Surveys

Two separate 3D seismic surveys support the appraisal programme, the smaller trade Redwater survey (35 km^2), and the larger proprietary Quest survey (415 km^2).

Redwater 3D Seismic Survey

The Redwater trade survey provides a cost-effective method to evaluate the requirement for acquiring proprietary 3D seismic data within the area of interest and to validate the 3D seismic acquisition design. Numerous small faults at the base of the BCS, all with throws less than 30 m, are evident within the Redwater survey but are not reliably recognisable within the two 2D seismic lines that cross the same faults. As these faults are a potential threat to well injectivity, 2D seismic is insufficient to help manage this risk through well placement. Re-processing results from a subset of the Redwater survey demonstrated a sparser, lower-cost, 3D seismic acquisition design was sufficient to properly image the BCS storage complex.

Quest 3D Seismic Survey

The prime region for development of the Quest CCS Project is within of the area of interest to maximise the distance of existing wells that penetrate the BCS storage complex and represent the greatest potential threat to containment. This is a prime reason for the proposed pipeline route. The HRAM and 2D seismic data covering this central region are insufficient to properly guide the placement of development wells given the potential of small geological structures such as faults or channels to limit the performance of any CO2 injector. To that end, the purpose of acquiring proprietary 3D seismic to image the central region of the area of interest is fivefold.

1. Validate the proposed pipeline route by demonstrating the BCS storage complex meets expectations.
2. De-risk the placement of appraisal, injection & monitoring wells by imaging basement structures and BCS thickness variations with sufficient resolution and sensitivity.
3. Identify any potential leakage pathways to guide MMV planning.
4. Include the nearby towns of Radway and Thorhild within the seismic image to support public acceptance of the Quest CCS Project.
5. Provide a baseline survey to support any future surface time-lapse 3D seismic surveys as part of the MMV programme to monitor the CO2 plume migration.

In total 415 km^2 of proprietary 3D seismic covering all 8 proposed injection well locations was acquired in two phases due to weather constraints and the early onset of spring in 2010.

5.1.3.4. Appraisal Wells & Injectivity Tests

Two early exploration/appraisal wells (SCL-Redwater 11-32-55-21W4M and SCL-Redwater 03-04-57-W4M) were drilled to support the site selection process and the request for exploration tenure submitted to Alberta Energy on December 16, 2009. A third well (SCL-Radway 8-19-59-20W4) was drilled as part of the programme of appraisal within the selected site. The two prime objectives for this well were:

1. Acquire data to inform regulatory application and SDP.
2. Retain the well for reuse within the project, preferably as a CO_2 injector.

The data acquisition programme included a short water injectivity test to estimate a lower bound for CO_2 injectivity without the expense of injecting CO_2. The results indicated good injectivity (380 m3/d/MPa) suggesting that three injectors could be sufficient to support the project pending the outcome of similar injectivity tests on the next two injection wells. A CO_2 injection test would only have been pursued in a low injectivity scenario to validate and refine the injectivity estimates and look for potential upside in the CO_2-brine displacement model. However, as Radway 8-19 confirmed injectivity high enough to take full Project volumes and Start-up rescheduling brought the potential introduction of first CO_2 into the first injection well forward to end 2014, a CO_2 pilot test was dropped from the appraisal plans early in 2011.

The water injection trial also aimed to test for the presence of any nearby flow barriers that may exist due to the small faults at the base of the BCS observed within the 3D seismic image. However, the test was unsuccessful in determining the presence or absence of barriers due to data quality issues, in particular water quality issues that lead to wellbore damage, and non-homogeneous flow behaviour resembling that of a laminated system which complicated interpretation using conventional Pressure Transient Analysis. [Ref 8.7 Quest Radway 8-19 Injection Test Report]

5.1.4. Introduction to Alberta pore space tenure and current status for Quest

On April 27 2011, the Government Of Alberta passed the Carbon Sequestration Tenure Regulation, which provided the means to apply for pore space tenure. The same month Shell applied for six (6) Carbon Sequestration Leases that together comprise the single proposed Quest CCS Project [Ref 5.4]. Shell requested the exclusive right for the following:

1. Drill wells, conduct evaluation and testing, inject captured carbon dioxide into subsurface reservoirs and otherwise develop all horizons within the zone of interest (ZOI), within the requested Area of Interest (AOI). Restriction of third-party access will ensure that exclusive right to the ZOI is for the sole purpose of the Quest CCS Project and associated MMV.
2. Test and sample all zones from surface to basement for the sole purpose of MMV, within the requested AOI, for the duration of the Carbon Sequestration Leases

a. Although this was requested in the tenure grant from government we only have the rights to test from the Top of the Elk Point Group to the Basement.

The CO_2 storage AOI that was granted by the Carbon Sequestration Leases is defined as the full extent of 39 townships plus 12 sections (the "Approved AOI"). Sections 1 through 24 of township 56-21W4 were included in the application for tenure, but were removed by Alberta Energy from the CO_2 storage AOI as approved because of pre-existing mineral leases for storage of petroleum liquids in salt caverns in the Lotsberg Formation within that township. *Table 5-4 Townships Included Within the Approved CO2 Storage AOI.*

Table 5-4 Townships Included Within the Approved CO2 Storage 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	20, 19 and 21 (sections 25 to 36 only)

In order to meet requirements outlined in the Carbon Sequestration Tenure Regulation, the CO_2 storage AOI was separated into six (6) contiguous Carbon Sequestration Leases that together comprise the single proposed Quest CCS Project. The leases granted by Alberta Energy are also shown in *Table 5-5 Approved AOI Separated into Assigned Carbon Sequestration Lease* Blocks and in *Figure 5-4 Quest CCS Project Carbon Sequestration Lease Blocks as Approved by Alberta Energy*

Table 5-5 Approved AOI Separated into Assigned Carbon Sequestration Lease Blocks

Sequestrations Leases	Township - Range (W of 4th Meridian)
591105001	59-18, 59-19, 60-18, 60-19, 60-20, 61-18, 61-19, 62-19
591105002	56-19, 56-20, 57-19. 57-20, 58-19, 58-20, 59-20
591105003	60-21, 61-20, 61-21, 62-20, 62-21, 63-20, 63-21
591105004	57-21, 57-22, 58-21, 58-22, 59-21, 56 -21 (Sections 25 to 36 only)
591105005	58-23, 59-22, 59-23, 60-22, 60-23, 60-24
591105006	61-22, 61-23, 61-24, 62-22, 62-23, 63-22

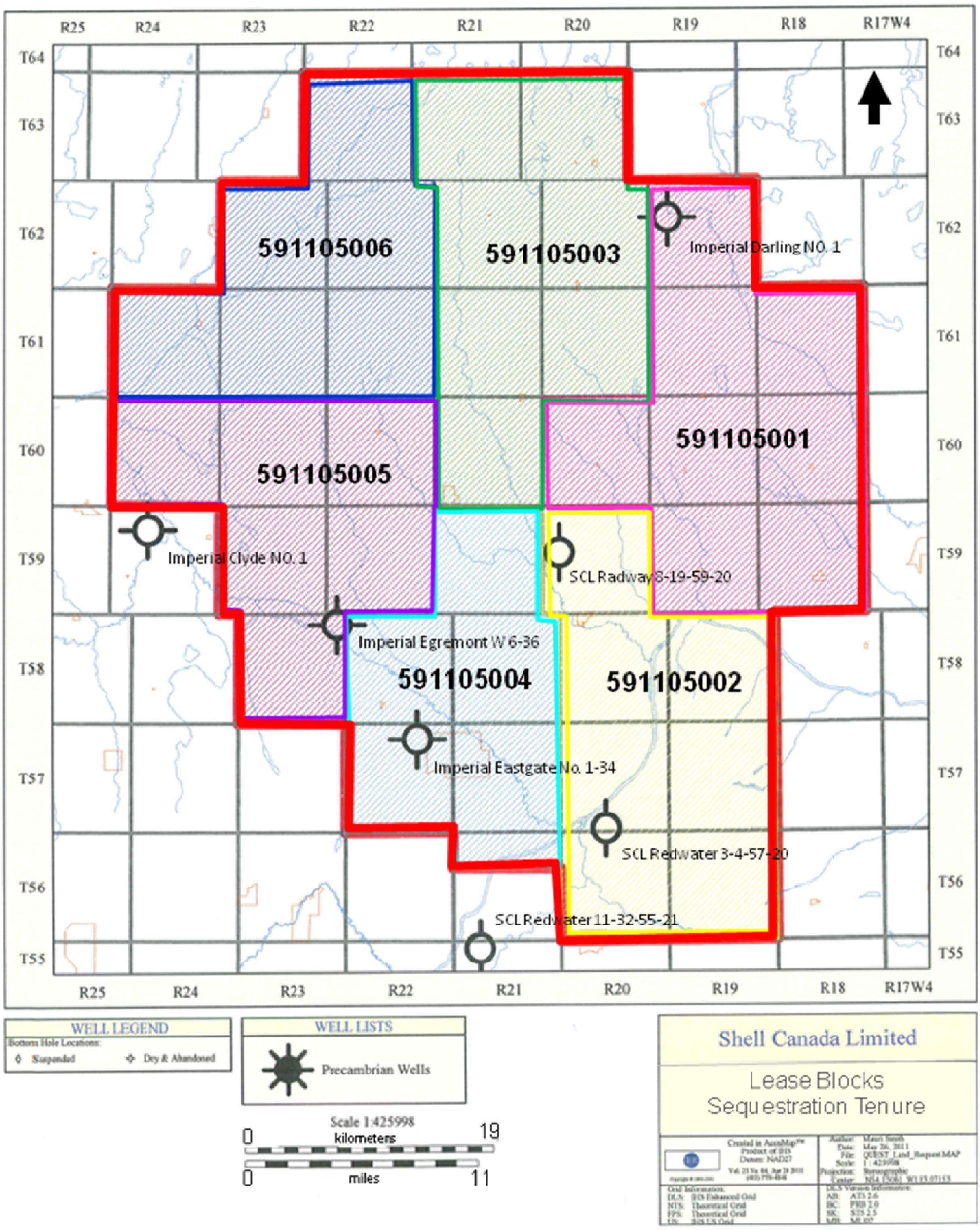


Figure 5-4 Quest CCS Project Carbon Sequestration Lease Blocks as Approved by Alberta Energy

5.2. Injection Well Site selection, ranking and phasing

As mentioned previously the iterative nature of this project has meant that some commitments have been made prior to having all the relevant information. For example the D65 Regulatory Submission was made prior to the final results of the appraisal campaign being available or incorporated into the Integrated Reservoir Model. This meant that a conservative approach was taken and the Nov 2011 D65 application refers to 3-10 wells based on the Gen-3 modelling results, with only 5 well locations identified and only 2 of those picked from 3D seismic.

5.2.1. Injection Well Site Selection

This Storage Development Plan intends to identify all proposed final locations for the injection wells before completion of the regulatory approval process. It should be noted that the continued appraise while developing strategy means that the final determination of the total number of injection wells will depend on the results of the tested injectivity in the next two injection wells, to be drilled in 2012. However, the currently available data and Gen-4 modelling has allowed the potential range of wells to be reduced from 3-10 to 3-8 as submitted to the Regulator as part of the June 2011 D65 Application update [Ref.2.5].

The first proposed CO_2 injection well, Radway 8-19, was drilled as an appraisal well in 2010. Locations for an additional four wells were identified in 2010 although at that point 3D seismic was only available over the southeastern part of the development area (covering wells 8-19 and 7-11 in table 5-3). Landowners were contacted, well sites were surveyed and well licenses were applied for (and later withdrawn at the regulators request) for these four additional injection wells before the submission of the D65 in November 2010.

The locations of the first licensed well and the four additional locations identified in the original November 2010 D65 submission are provided in *Table 5-6 Well Locations Included in the CO2 Storage Scheme Application*

Table 5-6 Well Locations Included in the CO2 Storage Scheme Application

Well UWI	Potential Injection well	NAD 27 UTM Zone 12 North	NAD 27 UTM Zone 12 East
08-19-059-20W4	1	5,997,747	370,705
07-11-059-20W4	2	5,994,417	376,674
10-06-060-20W4	3	6,002,874	370,401
12-14-060-21W4	4	6,006,367	366,539
15-29-060-21W4	5	6,010,249	362,409

In May 2011 the additional 3D seismic, acquired at the end of 2010, had been processed, allowing for seismic interpretation in support of well site selection. It also allowed a more thorough review of the subsurface reservoir characterization on the sites previously selected predominantly on surface constraints. The 3D seismic data now covers approximately 415 km2 or about 11% of the AOI and the latest processed data, indicates increased frequency content of the data (up to 100Hz) which for the first time allows for an interpretation of an event near the top BCS. Although the presence of strong multiples, the thickness of the BCS and the amplitude of the basement reflector present challenges for a reliable pick of top BCS, a BCS thickness map based on an isochron between the top basement and top BCS events can now be constructed from the 3D surface seismic. This map indicates BCS thickness and suggests the BCS to be thinning towards the north of the survey area as the Precambrian rises towards the "bald highs" interpreted from 2D seismic lines north of the Quest development area. Locations 12-14 and 15-29 in *Table 5-6 Well Locations Included in the CO2 Storage Scheme Application* now appear less attractive on the basis of the new 3D seismic data *Figure 5-5 BCS Thickness Map Annotated with Faults Interpreted at the Top Precambrian Basement, the Pipeline Route and the Eight Notional Proposed Well Locations*.

- The BCS thickness could be much reduced on the 15-29 location
- The 12-14 well appears to be located right on some NNW-SSE trending seismic features that could represent a ridge of Precambrian highs, likely associated with reduced BCS reservoir quality.

Therefore three additional infill locations were identified within the 3D seismic coverage area to complement the five existing locations that could no longer be moved due to regulatory and stakeholder constraints.

The exact locations of all eight injection wells submitted in the June 2011 update to the D65 submission and their notional drilling sequence are provided in *Table 5-7 Final Well Locations Included in the Updated D65 Scheme Application*. Further details and seismic cross-sections through these locations are provided in Appendix 3.

- The wells in the green rows in *Table 5-7 Final Well Locations Included in the Updated D65 Scheme Application* represent the expectation case that comprises only three injection wells and can be developed with Phase 1 of the pipeline only.
- The base case five injection well development case is represented by the Phase 1 wells (in green) and the next two rows in yellow that would be drilled in 2013 along with the construction of Phase 2 of the pipeline. It is currently envisaged that full system start-up can be achieved with three to five wells.
- If injectivity cannot be sustained at sufficiently high levels Phase 3 will need to be implemented. Phase 3 comprises up to three infill wells (orange rows) and the final 6" pipeline extension to the pipeline endpoint from the Regulatory Application. It expected that these injection wells will not be drilled until after start-up with sufficient lead time to be provided by the early field performance data of the development.

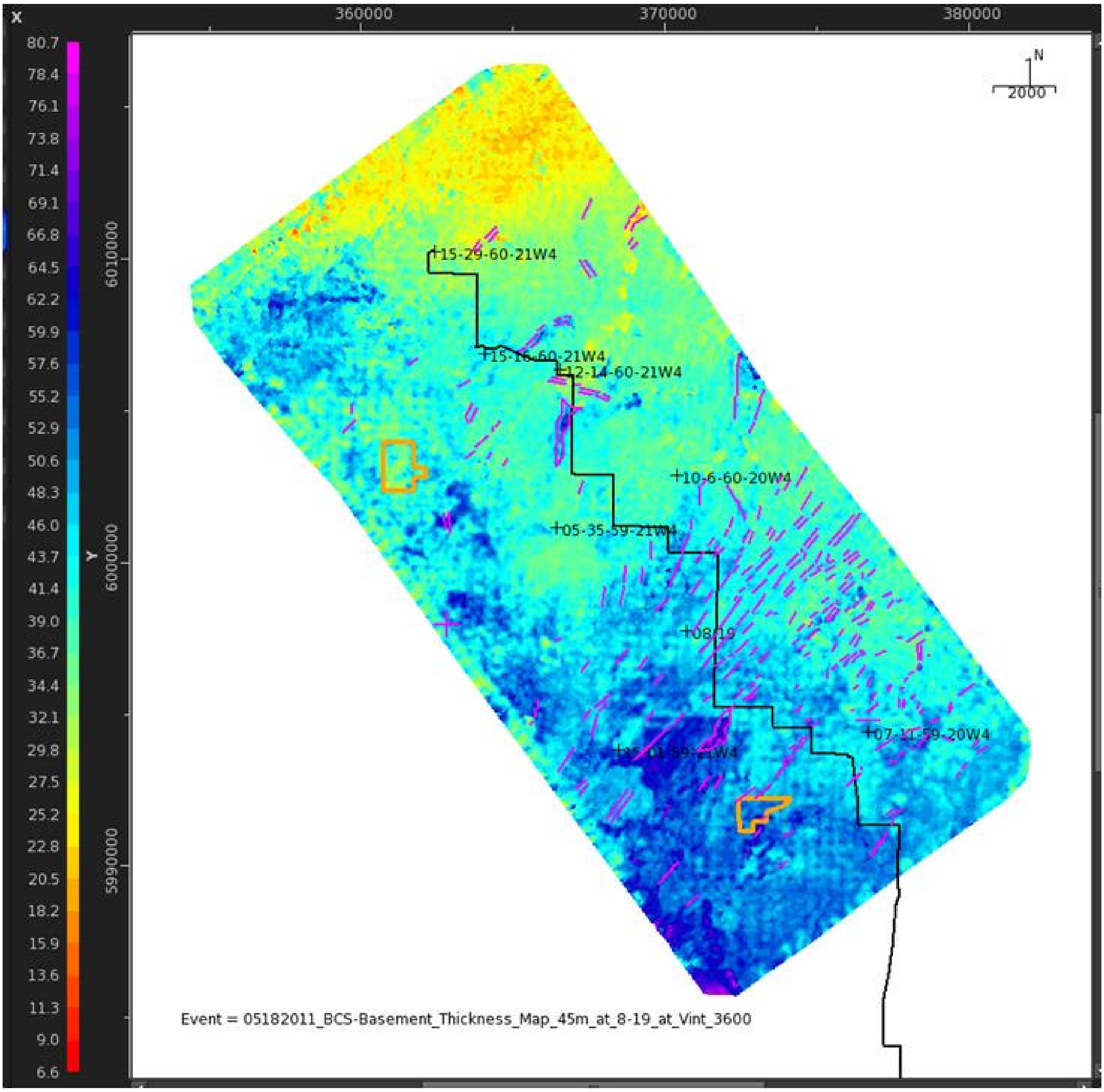


Figure 5-5 BCS Thickness Map Annotated with Faults Interpreted at the Top Precambrian Basement, the Pipeline Route and the Eight Notional Proposed Well Locations

Table 5-7 Final Well Locations Included in the Updated D65 Scheme Application

Drill order	Timing	Well UWI	NAD 27 UTM Zone 12 North	NAD 27 UTM Zone 12 East
1	2010	8-19-59-20W4	5,997,747	370,705
2	2012	7-11-59-20W4	5,994,417	376,674
3	2012	5-35-59-21W4	6,001,157	366,423
4	2013 Contingency	15-16-60-21W4	6,006,879	364,049
5	2013 Contingency	10-6-60-20W4	6,002,874	370,401
6	>2015 Contingency	15-1-59-21W4	5,993,780	368,543
7	>2015 Contingency	15-29-60-21W4	6,010,249	362,409
8	>2015 Contingency	12-14-60-21W4	6,006,367	366,539

At the time of writing, the three additional injection wells identified post regulatory submission, were in the process of negotiations with surface land owners for final location approval. As a result, the locations and the associated names may change according to land owner preference. However, only minimal movement is expected (less than 1km in any direction).

5.2.2. Injection Well Site Ranking

Once a total number of eight injection wells were sited, to align with the redefined subsurface scope of three to eight injection wells, all locations were ranked to establish a notional drilling sequence. Pre-requisites for making the ranking list were:

- Land owner consent must be in place
- Minimum offset distances to road and other infrastructure must be met (due to lack of dedicated CCS regulations a conservative approach was taken by using existing H2S offset requirements).

The prioritized list of ranking criteria that was developed for the final location selection in this SDP is:

- Offset to population centres (Radway and Thorhild). All locations were pre-screened to be a notional 5km from population centres.
- Reservoir quality/thickness indicators from 3D seismic (injectivity).
- Distance from Scotford/Impact on length of 12" pipeline (pipeline cost).
- Distance from edge of 3D survey (conformance and MMV costs).

- Intra injector well distance (sustained injectivity).
- Offset to residences. Not a real differentiator in the list of eight locations as almost all residences are further away than 450m and thus outside pipeline EPZ.
- Distance to legacy wells.
- Length of lateral to 12" pipeline - Some overlap with the 3rd bullet point as some wells can either be reached by long lateral or a P/L extension)

The result of this ranking process with details on offset distances to the pipeline, the edge of the 3D seismic survey, other injectors, the legacy wells and nearby roads, houses, towns and aerodromes is provided in an overview in *Table 5-8 Final Ranking Matrix for the Eight D65 Well Locations.*

Table 5-8 Final Ranking Matrix for the Eight D65 Well Locations

Order	Well ID	Isochron	Key offset distances						Comments
		ms	Pipeline	Survey	BCS Legacy wells	Infrastructure	Intra well	Pipeline	
1	8-19-59-20W4	25	1.1km	NE= 7.1 SE= 10.6 NW= 18.8 SW= 6.6	Darling = 31km Egremont = 21km	House = 881m Road = 201m Radway = 5.8km	5-35 (3) = 5.5km 10-6 (5) = 5.1km 15-1 (6) = 4.5km	Phase 1 only	Well License: #0421182 Spud Date: 1 August 2010 TD date: 3 Sept.2010 Total Depth: 2132 m MD
2	7-11-59-20W4	29	1.2 km	NE= 4.2 SE= 4.4 NW= 25.1 SW= 9.4	Darling = 33km Eastgate = 23km	House = 800m Road = 680m Radway = 4.3km	8-19 (1) = 6.8km	Phase 1 only	
3	5-35-59-21W4	23	2.1 km	NE= 8.3 SE= 16.0 NW= 13.5 SW= 5.2	Darling = 30km Egremont = 18km	House = 413m Road = 320m Thorhild = 4.5km	8-19 (1) = 5.5km 10-6 (5) = 4.3km 12-14 (8) = 5.2km	Phase 1 only	
4	15-16-60-21W4	28	215m	NE= 7.1 SE= 21.9 NW= 7.5 SW= 6.6	Darling = 26km Egremont = 20km	House = 734m Aerodrome = 630m Railroad = 100.9m Thorhild = 4.0km	15-29 (7) = 3.7km 12-14 (8) = 2.5km	Phase 2	
5	10-6-60-20W4	22	2.1 km	NE= 4.1 SE= 14.9 NW= 14.5 SW= 9.4	Darling = 26.5km Egremont = 22.5km	House = 880m Road = 646m Radway = 8.8km	8-19 (1) = 5.1km 5-35 (3) = 4.3km 12-14 (8) = 5.2km	Phase 1 only	
6	15-1-59-21W4	28	4.7 km on right angles	NE= 11.2 SE= 8.8 NW= 20.6 SW= 2.6	Darling = 35.5km Egremont = 18km Eastgate = 16km	House = 811m Aerodrome=1.24km Road = 680m Radway = 4.2km	8-19 (1) = 4.5km	Phase 1 only	
7	15-29-60-21W4	17	0	NE= 6.5 SE= 25.6 NW= 3.8 SW= 7.8	Darling = 25km Egremont = 21.5km	House = 800m Road = 700m Thorhild = 6.9km	15-16 (4) = 3.7km 12-14 (8) = 5.7km	Phase 3	BCS thinning to North, close to tuning thickness
8	12-14-60-21W4	17	0	NE= 5.2 SE= 20.0 NW= 9.4 SW= 8.2	Darling = 25km Egremont = 21km	House = 565m Road = 274m Thorhild = 5.9km	5-35 (3) = 5.2km 15-16 (4) = 2.5km 10-6 (5) = 5.2km 15-29 (7) = 5.7km	Phase 2	On edge of PreCambrian high, but right on some NNW-SSE trending seismic features

5.2.3. Injection Well Phasing and Decision Milestones

It should be noted that due to the sparse data set that forms the basis of the Storage Development Plan there is an element of continuing appraisal while developing. Therefore the base case Storage Development Plan comprises five injection wells in total with an opportunity through continued appraisal while developing to reduce this number down to three injection wells by Q4 2012. The first injection well, Radway 8-19, is already in place as it was drilled in 2010 as an appraisal/keeper well. The next two injection wells will be drilled back to back in the summer of 2012 shortly after FID in Q1 2012. To optimize the chances of executing high quality water injection tests it will be important to avoid the busy winter season, when many well service providers suffer from resource constraints (staff and equipment) and start drilling early in the summer so that water injection testing can be finalized before the start of winter in November 2012.

The early drilling of the 2nd and 3rd injection well in 2012 rather than later during the development is justified for the following reasons:

1. Confirmation of the number of injection wells (3 vs. 5) is required prior to the final pipeline decision point by December 2012 to facilitate maximum cost savings on pipeline construction in a three injection well scenario *Figure 6-2 Schematic Overview of Pipeline Phasing.*
2. Well pads for groundwater monitoring wells need to be confirmed and constructed in time to acquire a 2 year baseline before start-up in January 2015.

The two injection wells to be drilled in 2012 will be drilled back-to-back for efficiency reasons as it will result in:

- Cost saving by:
    - i. Reducing rig mobilization costs
    - ii. Synergies and cost saving during well operations
    - iii. Potential savings in bulk purchase of well materials.

A decision point is required after drilling and testing injection wells #2 and #3 in Q3 2012. The base case Storage Development Plan will, at that point, either be reduced to a three injection well development with a reduced pipeline length through the Management of Change process, or the base case five injection well development will be executed and the order for the additional pipeline to the original D56 pipeline endpoint will be placed. The expectation is that the current data acquisition program including water injection tests on the next two injection wells will be sufficient to confirm a three injection well scenario. The decision on the final number of injection wells will be based on the following reservoir performance criteria:

1. Initial Injectivity
    a. If injection wells #2 and #3 to be drilled in 2012 are tested to have a combined injectivity exceeding an estimated 1.2 Mtpa CO_2 capacity (i.e. sufficient to meet

capture capacity in case of a Radway 8-19 well failure) then three wells are deemed sufficient to meet injectivity requirements for a Q4 2014 start-up. It should be noted that less than three wells is not considered due to potential for operational upsets and related impact on long term injectivity.
    b. If the combined estimated injectivity of these two injection wells falls short of 1.2 Mtpa CO_2 injection then it is expected that this injection capacity for start-up can be met by drilling either one (well #4) or two (wells #4 and #5) additional injection wells.

2. Sustained Injectivity – Although the expectation is that start-up can be achieved with between three and five injection wells it is possible that injectivity drops with time due to build-up of skin (e.g. formation damage, fines migration or halite precipitation in the near wellbore) or the build-up of pressure around the injectors due to storage capacity or reservoir connectivity issues. The site selection and identification of injection wells six, seven and eight is intended to mitigate the risk of gradually declining injectivity, because having these locations defined will reduce the time to bring additional injection wells on line after achieving start-up before end of 2015.
3. Conformance – If the CO_2 plume is growing faster than expected and is forecasted to migrate outside the 4.8km consultation radius or outside of the 3D seismic baseline within the 25 year injection period a decision is required between
    a. Drilling additional wells to contain plume sizes or
    b. Allowing for larger plumes with all associated stakeholder issues and MMV costs (i.e. larger 3D seismic area).

   The earliest decision point for this will be after three years of injection, based on the last notional set of annual 3D VSP surveys acquired in 2018 or alternatively shortly after 2022 when the first 3D surface seismic is notionally planned based on the MMV plan that is using Gen-4 plume model predictions. To effectively constrain plume size development it is expected that a decision to drill more injection wells to manage conformance is required in the first ten years of the injection period.

In both three and five injection well scenarios, additional back-up locations should be identified as a mitigation to unexpected Injectivity and Conformance issues, outlined above. These locations should be surveyed but well pads need not yet be constructed until Injectivity and Conformance issues can be more specifically identified through MMV and storage performance monitoring.

5.3. Well Site selection of deep MMV and groundwater wells

A full discussion of the logic behind the deep MMV wells and groundwater wells is available in [Ref 10.1] 07-0-AA-5726-0002 Quest CCS Project Measurement, Monitoring and Verification Plan.

5.3.1. Deep MMV Wells

Deep MMV wells are defined as observation wells that are drilled as part of the Quest Project and will be deeper than the base of the groundwater protection zone (BGWP) that generally defines the limit of the potable shallow aquifers. Four deep MMV wells are included in the development:

- **Redwater 3-4**: Conversion of the existing Project exploration well into a BCS pressure observation well.
- **Three Winnipegosis observation wells**: These wells will be drilled from injection well pads and are all planned to terminate below the Prairie Evaporites (the first seal above the BCS storage complex) to target the Winnipegosis as the deepest aquifer above the BCS storage complex. See Section 10 for further details. It should be noted that the final target interval for these wells will only be confirmed after appraising the Cooking Lake, Winnipegosis and Ernestina Lake Intervals in the Development wells to be drilled in 2012.

5.3.1.1. Conformance Monitoring

The current scope to monitor the conformance of the CO_2 storage through observation wells is limited to the conversion of the existing Redwater 3-4 appraisal well to a BCS Pressure monitoring well. This will provide a far field pressure point in the BCS to complement the continuous bottom hole pressures acquired in the injection wells and will help calibrate the shape and extent of the pressure distribution in the BCS monitored through InSAR. The scope of the Redwater 3-4 conversion is described in *Redwater 03-04-57-20W4* and has the following objectives:

1. Recomplete as a BCS pressure monitoring well
2. Provides a single point BCS pressure calibration for InSAR
3. If InSAR shows anomalous pressure increases then this will be used to determine if:
    c. Additional deep (BCS) MMV pressure monitoring wells are required e.g. near legacy wells.
    d. Additional injection wells are required for compartmentalization issues.

There are no further penetrations of the BCS planned for the purpose of monitoring conformance. However, there is a chance that evolving regulatory requirements may result in the request to drill additional observation wells in the BCS formation for direct saturation monitoring or other data acquisition purposes.

5.3.1.2. Containment Monitoring

The main objective of the deep MMV wells is to monitor for containment and act as early leak detection (or confirm the absence of leaks). The purpose of these observation wells is to support:

1) Pressure monitoring

2) Micro-seismic monitoring

Conceptual leak path models have indicated that a loss of containment is likely to be associated with a pressure signal in the reservoirs of the overburden. These pressure signals have far greater extent and are more likely to exceed threshold detection levels than any chemical fluid alteration associated with CO_2 or BCS brine migration out of the BCS storage complex. Two aquifers in the overburden above the BCS storage complex have been identified which may be suitable for pressure monitoring, the Winnipegosis and the Cooking Lake.

<u>Winnipegosis</u>

The primary target formation is the Winnipegosis aquifer which consists of both the Winnipegosis (WPGS) and Contact Rapids/Lower Winnipegosis Formations. The Winnipegosis carbonates and the underlying Contact Rapids/Lower Winnipegosis are an average of 19m and 63m respectively, within the AOI. The top of the Winnipegosis formation was penetrated in Radway 8-19 at 1600 m mD, some 441 m above the top of the BCS reservoir and 100 m above the top of the BCS storage complex.

1. The Winnipegosis has a potential feasibility issue as it is currently not clear whether the Winnipegosis can be used to monitor across large distances. The speed and extent of a pressure increase associated with loss of containment are hard to predict due to the heterogeneous nature of carbonates and the possible presence of reservoir discontinuities in the Winnipegosis.
2. Deep MMV wells on the injection well pads are expected to be effective in monitoring for well bore leaks and induced near well bore fracturing as pressure communication in the Winnipegosis is expected not to be an issue at these short distances.
3. To prove usefulness across a larger Area of Review (AOR) and monitor for unknown leakpaths further away from the injectors (e.g. faults) regional connectivity needs to be established. A production test followed by produced water reinjection or another type of Winnipegosis pulse test could be considered to prove this as an effective monitoring method for more remote and hence less probable leak paths.
4. The Winnipegosis has a single MDT pressure measurement in Radway 8-19 that indicates that this reservoir is 326 kPa above the extrapolated BCS pressure gradient. This pressure difference supports the hypothesis that the BCS and the Winnipegosis are isolated reservoirs, in line with the different chemical water signatures of these reservoirs.

<u>Cooking Lake</u>

The secondary target formation for pressure monitoring is the Cooking Lake carbonate formation. Within the AOI, the Cooking Lake Formation ranges from 44m in the west, reaches a maximum thickness of ~92m under the Leduc Reefs and then decreases to a thickness of 45m at NE edge of the AOI as it thins to its depositional edge. The abrupt thinning in the western portion of the AOI is related to the depositional setting of the Cooking Lake in relation to the North-South trending Rimbey Arc. This lineament partly coincides with a change in subsidence and accommodation space during Woodbend infilling resulting in the absence of Cooking Lake carbonates and preferential deposition of the time equivalent Majeau Lake shale. In the Leakpath model, the Majeau Lake shale is combined with the Duvernay shale for simplicity.

In Radway 8-19, the Cooking Lake Formation is 84m thick. It was intersected at 1148 m mD, some 893 m above the top of the BCS reservoir and 552 m above the top of the BCS storage complex.

1. The Cooking Lake has two MDT pressure measurements in Radway 8-19 that indicate that this reservoir is 660 kPa below the extrapolated BCS pressure gradient. This pressure difference suggests depletion, most likely due to production in the Redwater reef proving pressure communication across large distances.
2. The measured Cooking Lake depletion and the greater consistency of reservoir quality interpreted from offset logs over this formation suggests that there is a higher probability that the connectivity in the Cooking Lake is sufficient to monitor for leakage at larger distances away from injection pads. This could make the Cooking Lake more suitable than the Winnipegosis for pressure monitoring. However, as the Cooking Lake is shallower, has more penetrations and could be subject to dynamic production effects, the Winnipegosis is still the preferred primary target for deep MMV wells. The Cooking Lake will be carried as back-up target and the well design will need to allow for recompletion in the Cooking Lake if required.
3. Real Time Casing Imaging (RTCI) could be deployed as an alternative to traditional pressure gauges in the Cooking Lake. To prove feasibility of this technology both technologies will need to be deployed in the same formation in at least one location before proceeding to rely on RTCI only. Further feasibility work needs to be completed prior to deciding on inclusion of RTCI in the base case.
4. Other alternatives to incorporate the Cooking Lake back-up option in the deep MMV well design (e.g. dual completion, re-perforate, etc) need to be investigated.
5. Due to potentially ongoing pressure decline in the Cooking Lake formation a background decline trend would need to be established to allow a leak to be detected.

Some residual appraisal is required on these two target formations that can only be addressed before drilling the deep MMV wells by the injection wells planned to be drilled in the middle of 2012. It is anticipated that the back-to-back drilling of these two injection wells will provide a sequence that provides sufficient critical mass to mobilize and deploy a large hole diameter sampling tool to analyze Winnipegosis and Cooking Lake formations.

5.3.1.3. Number of Deep MMV Wells Required

Start-up with three injection wells

A number of MMV commitments were made to regulatory stakeholders during discussions on Supplementary Information Requests (SIRs) following the November 2010 submission of the Regulatory Applications *(Measurement, Monitoring and Verification (MMV))*. One of these commitments was to provide at least three deep observation wells. It is currently envisaged that in a three injection well scenario there will be a deep MMV well on each of the injection well pads, with approximately 40m separation between the wellheads of the injection and MMV well.

Two well types are currently being considered, a simple slim well bore option (type A) and a more complex large well bore option (type B) as illustrated in APPENDIX 6285.

a. The large well bore option type B is planned for the MMV well at the Radway 8-19 location with objectives to include microseismic monitoring and pressure monitoring:
   i. Classic microseismic can image up to 600m away from geophones.
   ii. Use to calibrate to microseismic from DAS fibre thought to only read up to 150m away from well. This can then be used to calibrate DAS microseismic in injection wells #2 & #3.
b. The slim well bore option type A is planned for the deep MMV wells at the well pad locations for injection wells #2 & #3 with its objective solely focused on pressure monitoring.

The deep MMV wells are currently not planned to contain any fibre optic cables as the MMV objectives for DTS and DAS can be met by incorporating the fibre in the injection wells and fibre optics in the deep MMV wells does not provide additional data acquisition opportunities.

<u>Start-up with four or five injection wells</u>

The containment monitoring requirements are expected to still be met by three deep MMV wells, even if more than three injection wells are required. Rather than maintaining a one-to-one ratio between deep MMV wells and injection wells, it is believed that risks can be managed by focusing the deep MMV wells on the highest risk wells. The injection wells central to the development are expected to see the largest pressure increases as pressures from surrounding wells will be superimposed on the pressure differential required to maintain injectivity.

All scenario's currently include a type B (**Error! Reference source not found.**) MMV well on the Radway 8-19 location, [Ref 10.1]. As soon as a decision on the number of injection wells is made in Q4 2012 the location of the remaining two slim bore type A wells can be made.

The expected logic for finalizing this decision is laid out below:

1) In case four injection wells are required for start-up, deep MMV wells will be placed on the well pads for injection wells 5-35 (3rd injector) and 15-16 (4th injector). Due to the BCS reservoir thinning to the North, observed from 3D seismic, these wells are expected to experience a larger pressure increase than 7-11 (2nd injector) in the South, expected to be the best injector of the development. This will be confirmed with the water injection test following the drilling of each well.
2) In case five injection wells are required for start-up, deep MMV wells will be placed on the well pads for injection wells 5-35 (3rd injector) and 10-6 (5th injector). Due to the triangular spacing of these three injection wells in the centre of the development, these

wells are expected to experience a larger pressure increase than 7-11 (2nd injector) and 15-16 (4th injector) at the extremities of the development.

5.3.1.4. Timing of deep MMV wells

The final depth and location of the three deep MMV wells will be decided the moment the number of injection wells required for start-up is known. This is expected to be shortly after the completion of water injection tests in injection wells #2 and #3 sometime around November 2012. The schedule also refers to a decision milestone of the final MMV well design in February 2013, some eight months prior to spud of the first deep MMV well, to allow for the procurement of long lead times and timely completion of detailed well design. It is planned to drill all deep MMV wells required in a continuous sequence following spud of the first one at the start of winter 2013.

The following considerations affect the timing of the deep MMV wells:

1. Deep MMV wells are not subject to seasonal variations and do not require a two year baseline.
2. A Cooking Lake MMV well would benefit from a 6 month baseline to establish background effects from ongoing regional production effects.
3. To be drilled before start-up before any leak could occur to establish baseline.
4. Current plan to start drilling end 2013 requires some Winnipegosis and Cooking Lake appraisal objectives to be incorporated in the 2012 drilling program for the next two injection wells (core, pressure and fluid sampling).
5. The decision point on final depths and well design will be in February 2013 after drilling and testing two injection wells in 2012. The well design needs to be robust to include a change to the Cooking Lake as the preferred monitoring formation in case Winnipegosis proves not to be feasible.

5.3.2. Shallow Groundwater Wells

5.3.2.1. Number of shallow groundwater wells required

A number of MMV commitments were made to regulatory stakeholders during discussions on Supplementary Information Requests (SIRs) following the November 2010 submission of the Regulatory Applications (see section 10 on MMV). One of these commitments was to provide at least three shallow groundwater wells. It is currently envisaged that in all injection well scenario's there will be at least one shallow groundwater wells on each of the injection well pads, with approximately 40-50m separation between the wellheads of the injection and shallow groundwater well.

The distribution of groundwater wells across the AOI will be following the below guidelines:

1. One shallow groundwater well per injection pad (total of 9 to 15 for 3 to 5 injectors).

The recognition of BCS tracers in the MMV plan means that triangulation of shallow groundwater wells is not required.

2. One shallow groundwater well per third-party BCS legacy well in the AOI (total of four, Eastgate, Egremont, Darling and Westcoast).
3. This leaves some groundwater wells unassigned (2, 4 or 6 respectively for the 3, 4 or 5 injection well case). A potential placement strategy for the last remaining shallow groundwater wells could be to involve the municipalities in the AOI and other local stakeholders. The following options could be considered for groundwater quality monitoring near potentially sensitive areas:
   a. Municipal water supply
   b. Residential areas
   c. Protected environmental areas
   d. Near higher risk contamination sites like:
      i. landfills
      ii. other industrial activity
      iii. Redwater 3-4 well site
      iv. Prairie Evaporite penetrations in the AOI: Thorhild 16-9 & 16-22

   Alternatively the remaining allocation of shallow groundwater wells could be used to triangulate three shallow groundwater wells on a single injection well pad to trial whether this provides additional insights on shallow aquifer properties over a single shallow groundwater per injection well pad. It is anticipated that this may be a Regulatory requirement post the November 2011 Hearing.

In the development area the shallow groundwater wells will target the lower Cretaceous Belly River group of formations, a clastic nearshore barrier bar system grading to coastal plain with coaly beds with a currently poorly defined stratigraphy. The objective of the shallow groundwater wells is to provide evidence for the absence of contamination from CO_2 or BCS brine migration from the BCS storage complex. To meet this objective the wells need to cover the potable aquifer in principle down to the base of the groundwater protection zone (BGWP). However, the depth of the BGWP currently in the ERCB database is typically around 200m below surface elevation whilst Radway 8-19 has shown a large discrepancy between the ERCB database and actual measured BGWP. The BGWP is defined as the contiguous interval containing less than the 4,000 mg/l Total Dissolved Solids (TDS) threshold. In Radway 8-19 this was observed to be at 138 m MD but confirmation of this depth is yet to be approved by the ERCB. From a review of most producing groundwater wells in the development area it can be concluded that most potable water is sourced from wells with a total depth of less than 100 m.

The groundwater well strategy to be followed for drilling and completing the shallow groundwater wells is outlined below:

1. Drill shallow groundwater wells as deep as possible without requirement for licensing (<150m below ground level).

2. Complete shallow groundwater wells in best aquifer zone (highest porosity and permeability zone) above the BGWP and below the vadose zone at depths between approximately 5 to10m.
3. Preferentially select the permeable zone above or below a competent barrier depending on the fluid most likely to migrate at that location.
   a. At third part-legacy well locations the risks are associated with BCS brine migration and therefore groundwater wells should be completed in a permeable interval directly overlying a non-permeable interval as brine contamination is expected to be subject to gravity segregation and move along the base of permeable intervals.
   b. At injection well locations the risks are associated with CO_2 migration and therefore groundwater wells should be completed in a permeable interval directly underneath a non-permeable interval as CO_2 migration is expected to be subject to gravity segregation and move along the top of permeable intervals.
4. As both the depth of the BGWP and the Belly River stratigraphy are not easy to correlate there is a need for a pilot well prior to finalizing a completion zone. Based on data evaluation from the pilot well, a preferred completion interval will be selected. The well will be either completed on the selected single interval or a second well could be required if the pilot hole cannot be plugged back to isolate the chosen completion zone.

5.3.2.2. Timing of shallow groundwater wells

The first groundwater well for the project was already drilled at the Radway 8-19 well pad location towards the back-end of 2010/early 2011 for early groundwater data acquisition purposes (1F1-08-19-059-20W400). Drilling of the next six shallow groundwater wells with known locations (well pads for injection wells #2 and #3 and four third-party BCS legacy wells inside the AOI) will start in July 2012 and take approximately 3 months.

The location of the first two unassigned groundwater wells needs to be determined by January 2012 to be ready for the summer 2012 groundwater drilling campaign so they can be drilled back-to-back with the six groundwater wells on known injection well pad and legacy well locations. In case a decision is made in November 2012 that more than three injection wells are required the remainder of unassigned groundwater wells need to be picked by January 2013 to be ready for drilling in summer 2013. These wells may not acquire a full two year baseline before first CO_2 is injected by end 2014 and will need to be correlated to trend observed from the first nine shallow groundwater wells.

The following considerations have informed the timing and sequencing of groundwater drilling in the Storage Development Plan:

1. A two year baseline is required to take into account seasonal fluctuations. Therefore the bulk of the groundwater wells needs to be drilled in 2012.

2. To avoid conflict with drilling and testing of injection wells #2 and #3 groundwater well drilling is to start with pilot wells at the legacy well locations.
3. Drill all pilot wells first to allow time to analyze data and choose final completion zone.
4. Then drill and complete all final shallow groundwater wells.
5. Evaluate keeping pilot wells completed as an option.

6. PIPELINE

6.1. System Description

The CO_2 produced in the Capture unit will be transported by pipeline to injection wells in the CO_2 storage area near Radway and Thorhild, Alberta. *Figure 6-1 Pipeline Route* on the following page provides an overview of the pipeline routing.

The pipeline consists of a buried high vapour pressure (HVP) pipeline that will transport dehydrated, compressed and liquefied CO_2. Also included are pigging facilities, line break valves, and monitoring and control facilities.

The pipeline will be composed of a 323.9 mm (12 inch) outside diameter steel pipe, with a wall thickness of 12.7 mm. There will be allowance for laterals to be tied-in. The proposed pipeline route extends east from Shell Scotford along existing pipeline rights of way through Alberta's Industrial Heartland and then north of Bruderheim to the North Saskatchewan River. The route then crosses the North Saskatchewan River and continues north along an existing pipeline corridor for approximately 10 km and then travels northwest to the endpoint well, approximately 8 km north of the County of Thorhild, Alberta. The total pipeline length to the regulatory pipeline endpoint is about 81 km. *Figure 6-1 Pipeline Route.*

Each injection wellsite facility will consist of a control valve (choke valve) and a mass flow meter fitted with pressure and temperature compensation. Similar mass flow measurement with pressure and temperature compensation will be at the compressor discharge. One of the proposed methods for pipeline leak detection is to compare the mass flow at the compressor discharge with addition of all mass flow at each well site. Comparison of all mass flow measurements will be done in Scotford Control room DCS system. Mass balance measurements from well sites will be used for CO2 storage calculations.

Based on the decision to phase the drilling of injection wells, as outlined in Section 5.2, there is an opportunity to phase the construction of the pipeline. If the two injection wells to be drilled and tested in 2012 prove to have good injectivity, the pipeline CAPEX can be optimized by building only the necessary 64 km of pipeline length rather than the full 81km to the endpoint in the regulatory application.

6.2. Regulatory and Land Acquisition

The D56 Application to get the 81km pipeline license [Ref 6.1] is expected to be approved by Q1 of 2012, as part of the bundle of applications that were submitted to the ERCB and AENV in November 2010. Once the license is approved, it is still possible to submit amendments to the application as long as they are submitted and approved before the actual construction of the laterals starts. The laterals from main line to wells are not included in the current D56 Application. It is expected that a final amendment will be submitted, that will include all the laterals, after the approval is granted. A phased construction approach could be submitted together with the laterals before construction is initiated.

At this moment most of the Right of Way (ROW) for the main trunk lines has been acquired. There are three tracks of land still outstanding, two of them being on Canadian Pacific Railway lands with the required "No Objection" obtained. The remaining track is R&S land for which "No Objection" has not yet been obtained. Shell has notified this landowner about the option to seek ERCB facilitation.

The acquisition of ROW for laterals is proposed to be phased. The ROW for the all eight of the injection wells in the sequence will be acquired to allow for completion of detailed engineering of the main trunk line and the laterals for the first five wells, and to reduce the regulatory uncertainty around the other wells.

6.3. Capture Facility and Third Party Interface

The engineering and procurement battery limit between the Capture facility and the Pipeline will be the inlet flange at the edge of the pig launching facility. The pressure at this interface shall be 14.5 MPag. There will be mating flanges in ANSI 1500# at the pipeline transitioning from ANSI 1500# to ANSI 900#at the discharge of the compressor. The design scope break will again lie at the flange at the edge of the pigging facility skid.

Instruments signals coming from the Pipeline SCADA RTUs at LBV and Well sites will be received by the SCADA host at Scotford and send to Capture's DCS via a DCS gateway.

Construction within Scotford Upgrader fence will be executed by different contractors than those outside the fence, with the delineation being the underground horizontal directional drilling crossing of road 214 located at the Scotford fence line. This crossing will be in the scope of the main pipeline construction contractor.

There are plans to have facilities to supply third parties consumers such as EOR operators, for this purpose, Quest pipeline will be fitted with a 12" -900# valve blinded off tie-in connection.

The tie-in connection for EOR operators will be located in the raiser of LBV-1, right upstream of LBV-1. The location was selected taking into account the following:

- Third party does not need to access Scotford plant
- Area close to route of EOR operators pipelines heading to their EOR fields
- LBV raiser is fitted with communication via SCADA system
- No need for a specific raiser for tie-in
- There are venting facilities at this location

Meter station for EOR's operator supply will be provided and installed by EOR operator. Flow, pressure and temperature indication to be sent to Scotford whenever third party supply is implemented via Quest Pipeline SCADA.

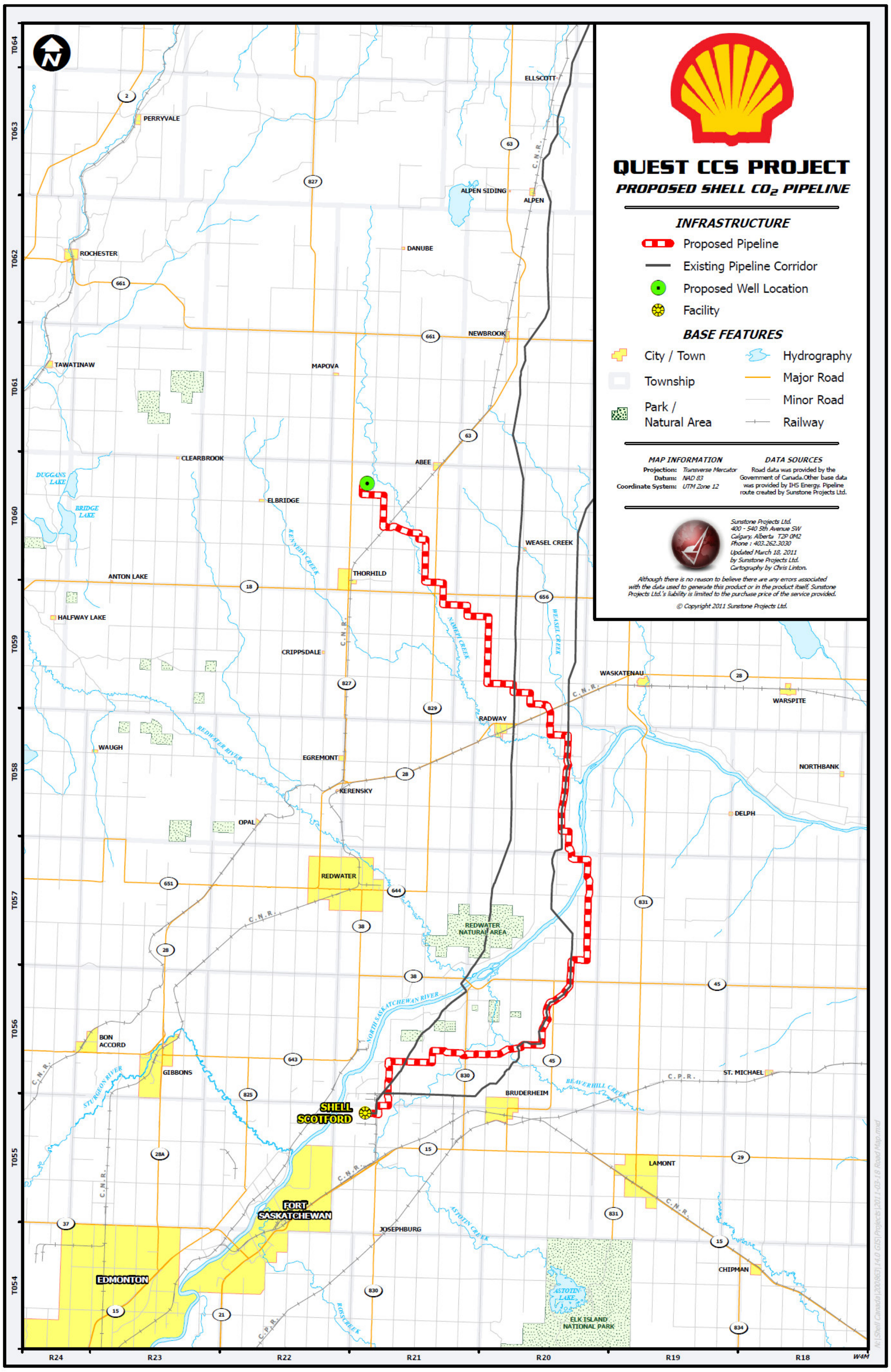


Figure 6-1 Pipeline Route

6.4. Wells Interface

The battery limit for the landing of the pipeline will be the inlet flange of the wing valve at the Christmas tree of the injection wells. The ESD valve at the inlet of the storage wells is part of the pipeline and will be installed downstream of the choke valve in the six inches lateral to each well. The pipeline lateral at the storage wells also includes:

- A check valve
- A 5 microns particles removal filter
- Corrosion coupon
- Mass flow meter (Coriolis type) with pressure and temperature compensation
- Meter prove taps
- Well choke valve, which can use either above surface gauges or downhole gauges as input signal
- Vent point
- Spare injection nozzle

All the facilities described above will be skid mounted, after the incoming raiser to the well site.

There will be a mating flange in API 5000# at the connection with the wing valve at the well head transitioning from ANSI 900#. The maximum operating pressure at this interface shall be 14.0 MPag

All controls signals above surface and downhole will be sent via a SCADA RTU to the SCADA Host at Scotford. MMV data will be managed via cellular network and FTP from Service Provider; only Well-head CO2 concentration gauge data will be transmitted via the SCADA, data will be managed by using internet protocols. Power supply to well pads will be via grid with UPS backup.

6.5. Pipeline Design

6.5.1. Design Conditions

The mechanical design conditions of the pipeline are in *Table 6-1 Pipeline Mechanical Design Conditions*, as such, an ANSI 900 class system has been chosen.

Table 6-1 Pipeline Mechanical Design Conditions

	Max	Min
Design Temperature	60 degC	-45 degC
Design Pressure	14790 kPag	-
Pipeline Rating	Class 900	

The pipeline shall be designed to carry up to 1.2 Mtpa CO_2 into five storage wells based upon the most conservative wells design case. The preliminary hydraulics simulations performed result in a 12" pipeline.

The model simulations performed also show a 14.5MPaa compressor discharge pressure coupled to a 12" NPS pipeline in the least conservative design case is able to inject up to 3.4 Mtpa CO_2 into five wells.

The Quest pipeline will be supplied by the CO_2 Capture facilities and therefore the inlet gas temperature is governed by the outlet temperature of the compressor and air-coolers downstream of it.

6.5.2. Pipeline Operation

A Thermal-Hydraulic model was developed for the pipeline, the following items were looked at: pipeline sizing, maximum system capacity, insulation requirements, vent-valve design, design requirements for above ground sections of pipeline, hydrate risk and its mitigation, dehydration limits, two-phase flow in pipeline & wellbore, slugging screening; operability aspects such as: vent procedure, start up, emergency pipeline leak, blow out, low flow operation and liquid hammer.

The optimum case to design and operate a CO_2 pipeline is to keep it in single phase flow at supercritical conditions where density is high and viscosity is low therefore maximizing transportation capacity. The minimum operating pressure is based upon CO_2 remaining in single phase flow during all operations. The simulations with 95% CO_2 purity in the pipeline show an extended 2-phase envelope up to approximately 9.3 MPag. The latest development at the Capture and Compression facility indicates that at least 98% of the time the CO_2 will be produced and sent to pipeline at 99% purity, this will allow the pipeline to operate at 8.0 MPag still keeping CO2 in dense phase conditions, therefore 8.0 MPag has been set as the minimum normal operating conditions when CO2 purity is 99%.*Refer to*

Table 6-2 Pipeline Operating Conditions.

The pipeline operations are safeguarded by a low pressure, high pressure, high water content and low CO_2 purity alarms (see section 12.4). Besides, the pipeline corrosion management is based on the following elements:

- Internal corrosion: the pipeline will operate with supercritical CO_2 with 4 to 6 lbs/MMscf, therefore no free water will be present and no corrosion inhibitor is required
- External corrosion: the pipeline will be equipped with an external coating and cathodic protection
- Monitoring: intelligent pigging will be performed regularly to detect corrosion. Corrosion coupons will also be installed at the wellsite

Table 6-2 Pipeline Operating Conditions

	Winter conditions	Summer conditions
Pipeline inlet temperature	43°C	49°C
Operating Pres		
Normal Min	8000 kPag	8000 kPag
Normal Max	11000 kPag	11000 kPag
Maximum	14000 kPag	14000 kPag
Flowrate		
Min	0.1Mtpa	0.1Mtpa
Expected	1.2 Mtpa	1.2 Mtpa
Water content	4 lbs/MMscfd (35 ppmw)	6 lbs/MMscfd (52 ppmw)
Ambient temperature	-40 degC	35 degC
Ground Temperature	0 degC	11 degC
OHTC		
Min	0.35 BTU/h/ft2/F	0.35 BTU/h/ft2/F
Max	1 BTU/h/ft2/F	1 BTU/h/ft2/F

The maximum pressure is based upon an injection scenario that has the highest allowable injection pressure into the formation as limited by the fracture extension pressure of the reservoir and surrounding formations.

The CO_2 is to arrive at the Quest storage wells battery limit at a max operating pressure of 14.0 MPag.

Another critical aspect of the simulated pipeline operation was hydrates formation during the seasonal periods, the main finding was that during winter the pipeline was prompt to get into the hydrate region if water content in the CO2 stream was in the order of 6lbs/MMscf, therefore the lower operating limit for water content was set to 4lbs/MMscf. Meanwhile during summer, the minimum water content was in the order of 8lbs/MMscf, thus the limit was set to 6lbs/MMscf.

Venting the pipeline was another critical operation modeled. During venting as consequence of J-T effect, the pipeline could reach extremely low temperature if the venting rate is not controlled. Pressure reduction measure will be implemented to avoid consequences of J-T effects. Topography also has its effect on venting, as CO2 in dense and liquid phase tent to accumulate at the low points of the line, it is recommended to vent any segment of the line from both ends to allow a more uniform temperature gradient along the segment.

Below is a summary table with the flow assurance mitigation strategies for the pipeline and well head:

Table 6-3 Flow Assurance Mitigation Strategies

Pipeline Section	Operation	Main risk/issues	Flow assurance mitigation strategy
Buried	Steady state flow	Hydrate formation	Buried to a min 1.5m =>dehydrate CO2 to 4lbs/MMscf in winter and 6lbs/MMscf in summer
min 1.5m	Shut-in	Hydrate formation	Dehydrate CO2 to 4lbs/MMscf inwinter and 6lbs/MMscf in summer
	Blowdown	Dry-ice / Metal minTemp	Follow proper venting procedure (dependant on soil properties, vent location, topography)
Above ground	Steady state flow	Hydrate formation	Dehydrate CO2 to 4lbs/MMscf in winter and 6lbs/MMscf in summer
	Shut-in	Hydrate formation	Temporary chemical injection upstrm of choke/ nothing in summer
	Blowdown	Dry-ice / Metal min T	Follow proper venting procedure (dependant on soil properties, vent location, topography)
Any shut in section	Venting	Metal min temp	To avoid metal min temp to be below -45C, 4inch vent's valve size is required
	Venting	Max vent rate	4inch size chosen due to min metal temp requirement is adequate for max rate
	Venting	Soil conductivity	Soil properties have large impact on minimum temperature - need to include soil layers
	Venting	Segment lenght	Minimum temperatures are observed closer to vent valve
	Venting	Ambient Temp	Minimum temperatures are observed at lower ambient temperatures: 4inch vent is adequate

6.6. Route Selection

The initial criteria for selecting the pipeline route were to maximize the use of:

- Existing pipelines right of ways
- Indisposed crown rights
- Fitness of the geology to cross North Saskatchewan River in a location capable of horizontal directional drilling

The original routing was due East to Bruderheim from Scotford Upgrader and then North. A subsequent re-route was made to avoid specific landowners in proximity to Bruderheim who were not interested in having a pipeline in their land. This routed the pipeline generally north and east of Scotford through the Northwest Bruderheim Natural Area and the Bruderheim Natural Area. After discussions with Parks, Tourism and Recreation, it was decided to avoid the Bruderheim Natural Area as they had plans for the main Bruderheim Natural Area that precluded a route as well as a requirement to purchase entire quarter-sections in the Northwest Bruderheim Natural area. Purchasing the entire quarter section would have also had Shell liability for legacy wells and remaining land. For these reasons, the route was finally chosen to run parallel to the recently installed 42" IPF pipeline.

The final pipeline routing has been selected with the following objectives:

- Limit the potential for line strikes and infrastructure crossings
- Align with the proposed CO_2 storage area
- Use existing pipeline rights-of-way and other linear disturbances, where possible, to limit physical disturbance
- Limit the length of the pipeline to reduce the total area of disturbance
- Avoid protected areas and using appropriate timing windows

- Avoid wetlands and limit the number of watercourse crossings
- Accommodate landowner and government concerns to the extent possible and practical

The Quest pipeline will start with the pig launcher next to the Compression area of the CO_2 Capture facilities located inside the Scotford Upgrader at Fort Saskatchewan. The pipeline routing within the Scotford Battery limits has been determined based on HSE ALARP work completed with Scotford Operations. *Figure 6-1 Pipeline Route*.

The well sites are located as described in section 5.2. To link the main trunk line with the well head a 6″ diameter lateral line will be layout for each well. The longest lateral line is about 3.5km to the well site and the shortest is around a 30 meters.

The route of the laterals has already been chosen, and non-objection request are underway.

The total length of the pipeline is between 64 and 81 km, depending on the final number of injection wells required to meet the Project's objectives (*Figure 6-2 Schematic Overview of Pipeline Phasing*) and the total length of laterals is about 12km.

6.7. Pipeline Phasing and Schedule

6.7.1. Pipeline Phased Construction

A three-phased pipeline execution approach has been developed to optimize opportunities for costs savings whilst remaining robust for subsurface uncertainties. The uncertainty range around well injectivity is expected to be significantly reduced injectivity following completion of water injection tests in September 2012. A schematic overview of the phased pipeline construction approach is provided in *Figure 6-2 Schematic Overview of Pipeline Phasing* on the next page.

Phase 1

Phase-1 will feed the first three injection wells and comprise a 12″ main trunk pipeline with a total length of 64km. A pig receiver will be included in the design and installation of the LBV at the 64km point. The laterals to the first three injection wells will be built together with main trunk line. The following features will allow for expansion of phase 1 should more injection wells be required to support the development:

- A tie-in point at the 64km LBV to extend the 12″ trunkline (wells 4, 7 & 8).
- A tie-in point for a lateral to well 5 at the 64km LBV point.
- A tie-in point for lateral to well 6, at around 57km, will be left at the closest LBV station. To be defined during detailed design.

Potential savings in the ROW length by 17km (CAD ~15 mln) could be achieved if the pipeline construction can be limited to Phase-1 only (three injection well scenario).

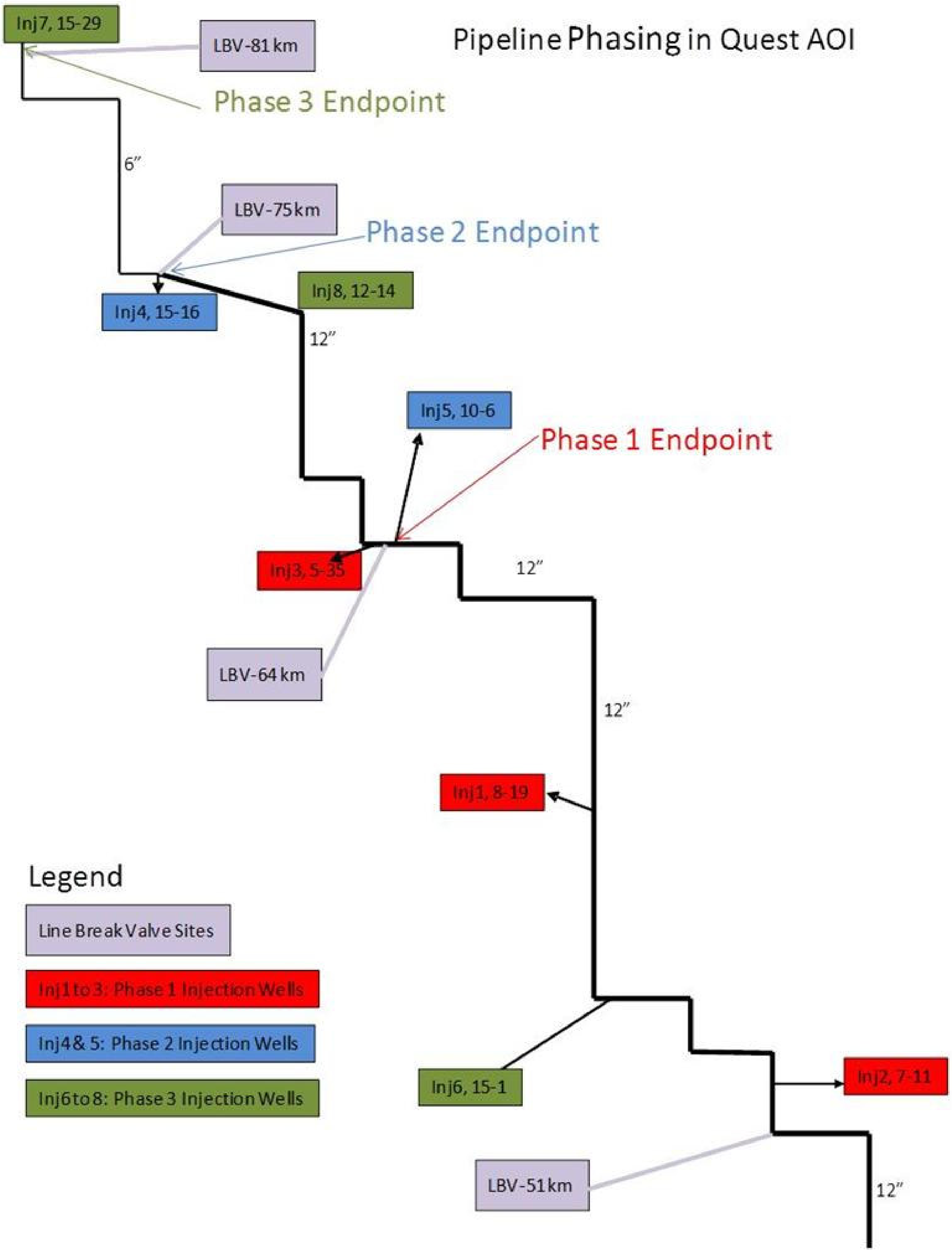


Figure 6-2 Schematic Overview of Pipeline Phasing

Phase 2

Phase-2 will extend the 12″ pipeline from 64km to 75km to feed injection wells 4 and 8, it is expected that this decision will be made at the end of 2012 or early 2013 well in advance of construction start. A LBV will be added at the new 75km pipeline endpoint with a pig receiver included in the design and installation of the LBV at the 75km point. Injection wells 4 and 8 are located very close the 12″ pipeline and will require very short laterals that can be constructed once the wells have been drilled. The following features will allow for expansion of phase 2 should more injection wells be required to support the development:

- A tie-in point for a lateral to well 7 at the 75km LBV point.

Potential savings in the ROW length by 6km (CAD ~5 mln) could be achieved if the pipeline construction can be limited to Phase 1 and 2 only (three to six injection well scenario).

Phase 3

Phase-3 will comprise a 6″ lateral of 6 km length from the 75km LBV to the original pipeline endpoint in the regulatory application. The lateral will follow the same route as the ROW for the 12″ pipeline in the regulatory application. A LBV will be added at the new 81km pipeline endpoint but no pig receiver will be included at this site due to the change in pipeline diameter at the 75km LBV. Injection wells 7 is located at the end of the 6″ lateral. There will no special allowances for further expansion north from the end point at 81 km. This lateral will be built when injection well 7 (15-29) is drilled.

Potential savings of approximately CAD ~1.5 mln could be achieved due the drop in line size over the last 6km of the ROW between LBV sites at 75 and 81 km (seven or eight injection well scenario).

6.7.2. Line Pipe Order

The order for line pipe material is planned to be issued in three stages:

- A first order around January 2012 to get some 500 to 800 meters to build the underground line at Scotford in August 2012 to synergize with other underground construction scope for the Capture facilities.
- A second order to cover the initial 64km of ROW in November 2012.
- A third order for the remaining 11km or 17km to reach Well-4 or Well-7 respectively, to be placed in May 2013.

Long lead items such as LBV-75km skid and meter skids for injection wells 4 & 5 will need to be ordered no later than January 2013 to secure the construction schedule if contingency injection wells 4 and 5 are required in 2013.

6.7.3. Pipeline Construction Contract

The detailed design will comprise the entire pipeline scope and include options to include phase 2 and 3, should these be required.

The current pipeline schedule requires the Pipeline Construction Contract to be awarded in June 2013 to allow enough time to mobilize the HDD Contractor at the crossing of North Saskatchewan River by September 2013 so that actual construction of the rest of the pipeline can start in winter 2013. The pipeline is expected to be mechanically complete with cleaned ROW by September 2014. CO_2 will be available to the pipeline by end 2014 after commissioning and start-up of the HMU3 capture facility to allow for start-up and commissioning of the wells shortly after (planned January 2015).

To meet the contract award date, pre-qualification and bidding process is planned to start on December 2012, with the actual bidding taking place in February 2013. The bid of the construction scope of work will include firm scope for Phase 1 with an option to expand in Phase 2 to lock the price.

6.8. Pipeline Facilities

The starting point of the pipeline at the CO_2 Capturing area shall include a pig launcher. Provision shall be made for pig traps at approximately the midpoint location in the pipeline, located before the major river crossing. The CO_2 from the Capture facility shall be fiscally metered.

The following shall be placed within the fence of the Pigging stations and or injection wells:

1. Pig Traps
2. Metering skids
3. Flow Control Valves
4. Particulate control equipment to protect the injection wells
5. Vent for cold venting the pig traps and other pressurised equipment during maintenance

6.8.1. Metering and Control

The system is envisioned to operate in a manner that would have the Directive 17 metering performed at the Scotford facilities, with a meter located at each wellsite for control and allocation purposes only. This scheme needs to be mutually reviewed and approved by ERCB and Shell.

The metering skids are located at the inlet of the wellhead, for CO2 dense phase service, Coriolis type mass flow meter with inbuilt temperature and pressure compensation will be done to calculate the mass flow. Data from each well head will be collected by its respective RTU and sent to SCADA Host located at Scotford. SCADA host will be interfaced to DCS system where mass balance will be performed. Mass flow of each wellhead will be totaled by the RTU and this data send to the host RTU at the Scotford via SCADA to perform mass balance calculations. A flow control (Choke) valve at the well site will control flow to the injection well based on the local Flow controller. This Flow controller has over ride from pipeline Pressure Controller. In the event of pipeline pressure reaching lower than the set valve, Pressure Controller will override the flow controller and control the Choke to maintain the pipeline pressure *Figure 6-3 Metering at the Wellhead.*

6.8.2. Line Break Valves

Line Break Valves (LBV) are normally provided to isolate the pipeline in segments for the protection of the environment and the public in the event of loss of pipeline integrity, maintenance, operation, and repair. The Quest pipeline will be isolated a maximum of every 15kms, at the Quest Capturing facility, and at the well heads.

The LBV will be ball type with single metallic stationary seat, with sealing capacity in both directions to avoid the problems of trapped pressure between seals.

The LBV arrangements are equipped with vent facilities located at each side of the valves with the objective of:

- Pressure monitoring at both segments of line
- Vent the pipeline segment at each side of the valve independently.
- Pressure control to ensure metal minimum temperature is not reach during venting
- Pressure transmitters located upstream and downstream of the respective LBV's will be used during pipeline pressurization and depressurization. Low pressure signal from two out of two Pressure transmitters will be used as another method of pipeline leak detection. In the event of any LBV closes, signals will be send out to all the LBV's to close to isolate each segment of the pipeline.
- In the event of 1st LBV closure as a result of pipeline Leak detection, XV-001 at the compressor discharge will be closed and compressor will be put in re-circulation mode. This logic will be in place to reduce the consequences in the event of small leak between 1st section of pipeline segment (Scotford site and 1st LBV site).
- Figure 6-4 A LBV Station

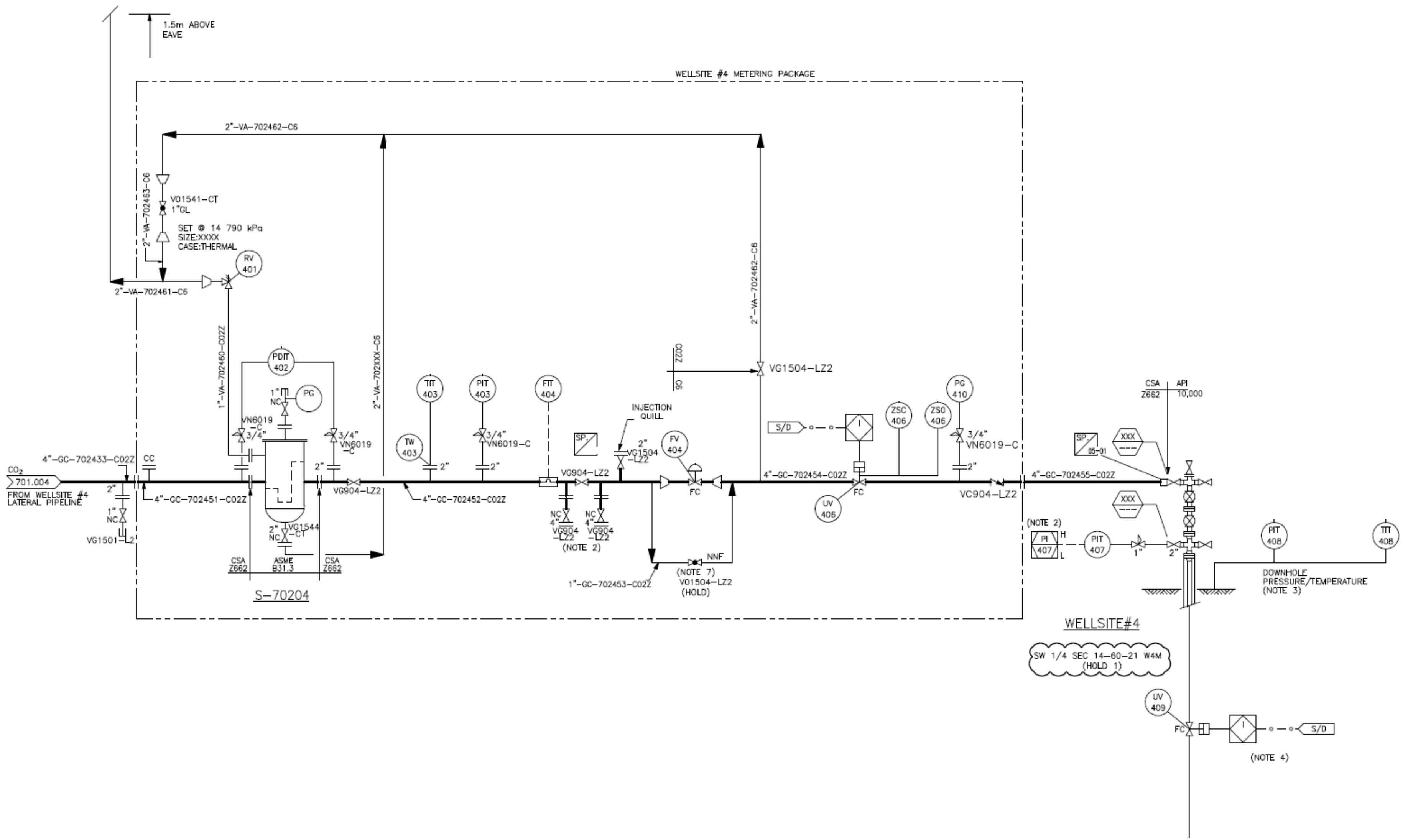


Figure 6-3 Metering at the Wellhead

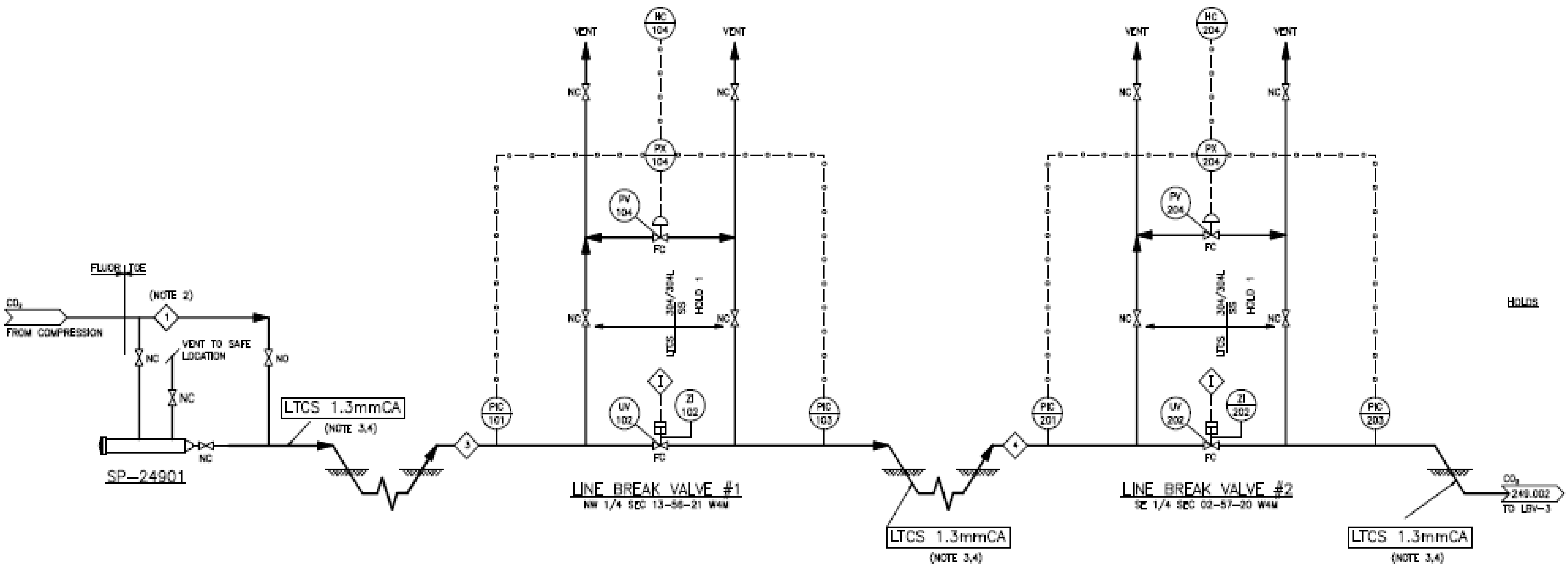


Figure 6-4 A LBV Station

7. INTEGRATED PROJECT DESIGN

There are three key areas that define the operating envelope for the integrated injection systems these are:

- The Bottom Hole Pressure (BHP) – there is a D65 and D51 Regulatory requirement that the reservoir pressure does not exceed 90% of the fracture pressure.
- The Compressor and Pipeline size
- Flow Assurance issues

Project timeline constraints meant that the final decision on the pipeline and compressor design were made in Q1 2010, while the first well in the centre of the AOI (Radway 8-19) was not drilled until Q3 2010 and the water injection test was not finalised until Q4 2010. Therefore, the chosen operating conditions and compressor design needed to be robust against a wide range of subsurface realizations.

7.1. Bottom Hole Pressure Limitation

The ERCB Directive 51 guidance stipulates a 10% safety factor by constraining maximum injection pressures to 90% of the measured fracture extension pressure of the BCS storage formation. Fracture initiation and growth may be prevented by ensuring that bottom-hole injection pressure constraints stay below the fracture extension pressure within the BCS.

Although fracturing of the BCS is undesirable for CO2 plume development and might cause loss of conformance, it does not threaten containment unless these fractures propagate upwards and remain open through all the seals within the BCS storage complex.

7.1.1. Minifrac Data

For a summary of the fracture extension pressures (FEP) and the fracture closure pressures (FCP) over the BCS and LMS, from the minifracs completed in the Redwater 11-32 and Radway 8-19 wells see the table below.

Table 7-1 Summary of Minifrac and Microfrac Fracture Pressure for the Quest Appraisal wells

Test	Interval Depth (m)	Formation	FEP (MPa)	FCP (MPa)
Redwater 11-32	2,122.0–2,123.0	LMS	37.0	33.4
Redwater 11-32	2,150.5–2,151.5	LMS	37.9	35.2
Redwater 11-32	2,188.0–2,193.0	BCS	45.4	31.7
Radway 8-19	2,048.5-2,049.5	BCS	42.4	34.6

As the offset Well Redwater11-32 is located down dip from the planned CO_2 injection wells, a correction for depth needs to be applied to the fracture data, by converting the fracture pressure to fracture gradients *Table 7-2 Summary of Fracture Gradients from Minifrac Test for Quest Appraisal Wells.*

Table 7-2 Summary of Fracture Gradients from Minifrac Test for Quest Appraisal Wells

Test	Interval Depth (m)	Formation	FEP (kPa/m)	FCP (kPa/m)
Redwater 11-32	2,122.0–2,123.0	LMS	17.4	15.7
Redwater 11-32	2,150.5–2,151.5	LMS	17.6	16.4
Redwater 11-32	2,188.0–2,193.0	BCS	20.7	14.5
Radway 8-19	2,048.5-2,049.5	BCS	20.6	16.8

The Fracture Extension Pressure (FEP) gradient in both wells is consistent, confirming the BCS fracture pressure in the Quest area of interest. The Fracture Closure Pressure (FCP) gradient is lower in the Redwater 11-32 well, providing the most conservative estimate for closure pressure.

Other information available from Radway 8-19 that supported the proposed operating window came from the Leak Off Test (LOT) at the 9 5/8" (244.5 mm) casing shoe in the LMS formation. The results of this test indicate a Fracture Extension gradient in the LMS of 17.4 kPa/m, exactly as per the minifrac results in the LMS in Redwater 11-32.

LMS versus BCS fracture gradients

High levels of confidence are required due to Quest being a CCS demonstration project with high demands on long term safe disposal and storage of CO2. Therefore, as the Lower Marine Sands (LMS) which is the first formation overlying the BCS storage formation has the lower fracture gradient the Quest project team has chosen to provide an additional safety margin by selecting the fracture extension pressure of the Lower Marine Sands (LMS) as the BHP limitation. This provides an additional 15% safety margin, because the LMS fracture extension pressure was measured at 17.4 kPa/m versus 20.6 kPa/m in the BCS. The Quest project team feels this is a more appropriate constraint, as the first barrier to loss of containment is the avoidance of fractures propagating into the overburden and the LMS is the first formation above the BCS in that sequence.

Based on the above, the bottom hole injection pressures for the commercial well design and the D65 regulatory application wills 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 corresponds to a bottomhole pressure constraint of 32 MPa (90% safety factor already applied).

Reservoir Cooling

An additional safety margin may be required to protect against the known phenomena that reservoir cooling may result in reduced formation strength and lower fracture gradients. To ensure that the Quest development scheme is robust against a significant loss of formation strength due to cooling, a decision was made to allow an additional 4 MPa safety margin over and above the limit imposed by the LMS fracture extension pressure, reducing this to 28 MPa. The thermal modelling work supporting this decision is documented in GEN 4 IRM [Ref 8.2]

An illustration of how the selected bottom hole pressure constraint at start-up (28 MPa) compares to the measured BCS fracture pressures at expected top BCS perforations (42 MPa) to provide a 14 MPa safety margin is provided in *Figure 7-1 Fracture Pressure Waterfall Chart, Showing Incremental Safety Margins Applied.*

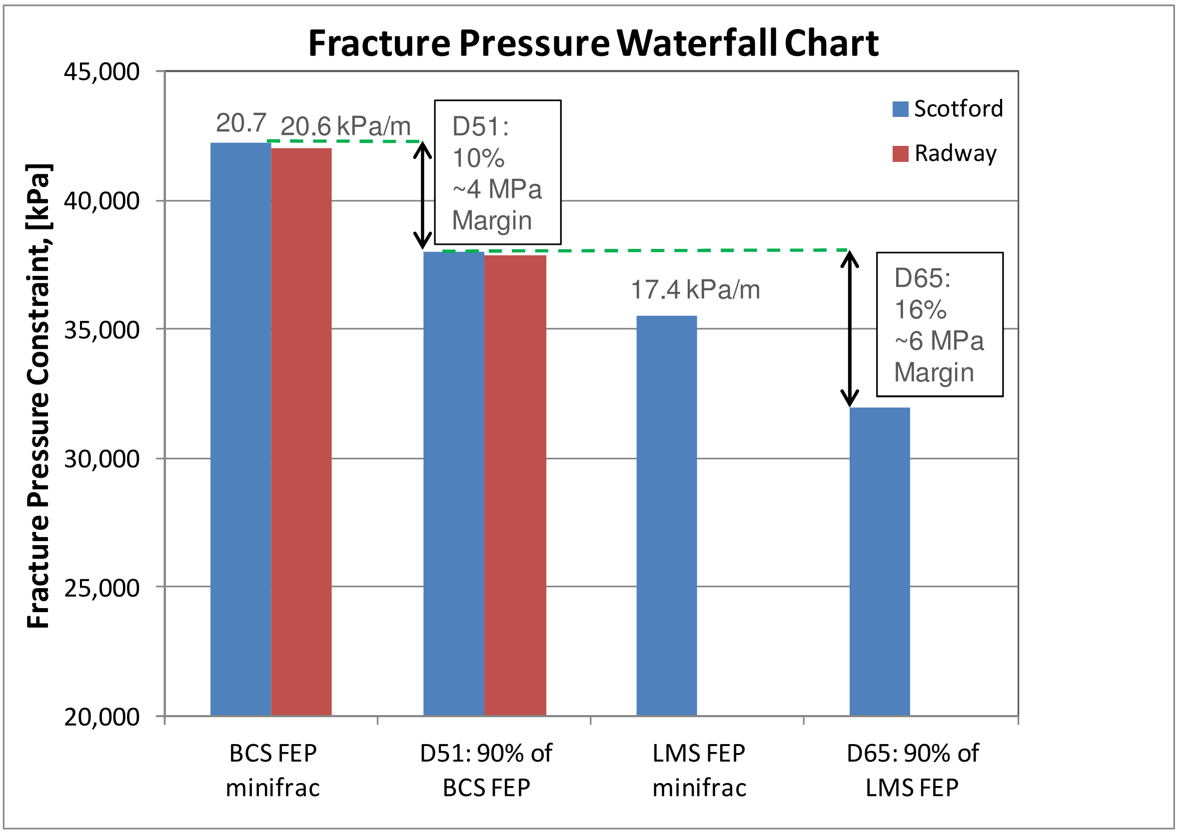


Figure 7-1 Fracture Pressure Waterfall Chart, Showing Incremental Safety Margins Applied

The premise here is that additional information on formation strength and fracture behaviour may become available from the Quest MMV program (e.g. microseismic) several years into commercial operations. Therefore:

- It would appear prudent to start operations with a bottom hole pressure constraint of 28 MPa, whilst data is collected in those first few years to support a gradual move to higher pressure should operations so require.
- It is expected that at least three years of injection data at commercial rates is required before a decision could be made to safely increase the initial BHP constraint from 28 MPa to 32 MPa or anywhere in between.

To ensure consistency in design, all subsurface scenario modelling was constrained by the assumption of a 28 MPa life cycle bottom hole pressure constraint to ensure full field injection capacity of 1.2 Mtpa could be maintained for 25 years with the range of injectors provided in the D65 (3 to 8).

However, the regulatory submission has been based on the potential upside of a maximum bottom hole pressures of 32 MPa and the wells and pipelines are designed for an operating envelope consistent with a 32 MPa maximum BHP constraint for the following reasons:

- To overcome possible short-term start-up effects.
- As an option to re-wheel the compressor at a later date (not foreseen within first 3 years) if additional injection data supports an increase of the BHP constraint to 32 MPa should poor reservoir conditions make this change necessary.

7.2. Integrated Production Systems Modelling IPSM

7.2.1. Compression & Pipeline Requirements

The General Allocation Package (GAP) within the Integrated Production Modeling (IPM) toolkit was used to confirm a compressor with a 14.5 MPa discharge pressure is sufficient to provide the necessary wellhead and bottom hole pressures to inject the minimum 1.2 MT/yr CO2 required for the Quest CCS project under the conditions studied (100% up-time of facilities and injection).

Quest's integrated injection modeling system includes the integration of the surface network with the well model, see *Figure 7-2 Example of Quest GAP network connecting surface components and wells*

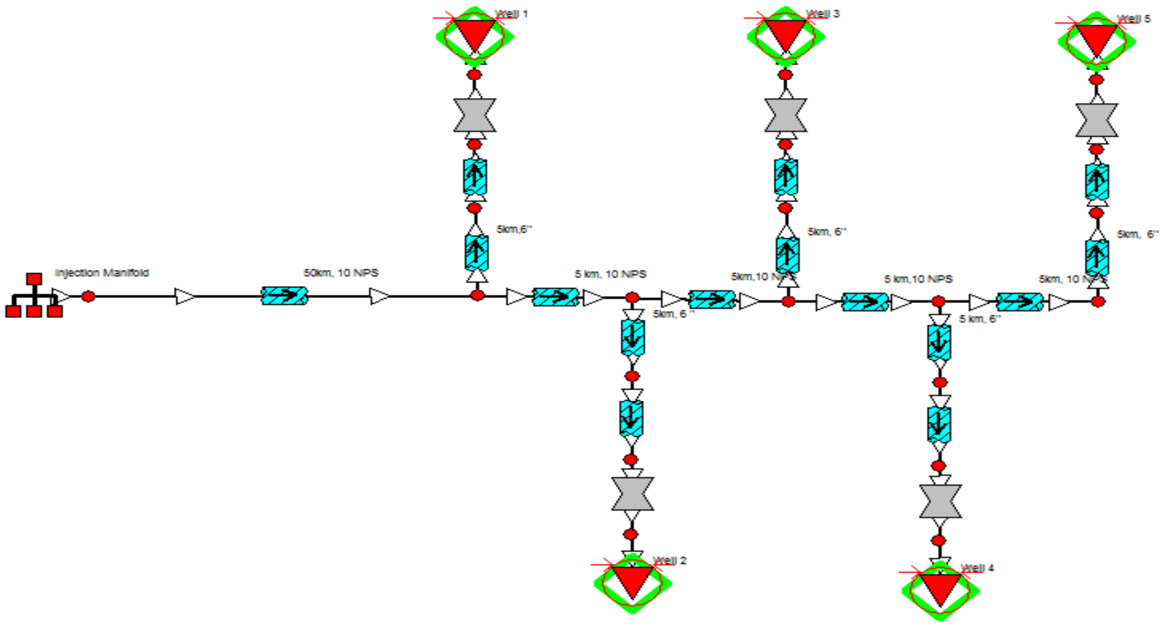


Figure 7-2 Example of Quest GAP network connecting surface components and wells

GAP was used to model the pressure and temperature losses across the pipelines from the compressor (i.e. Injection Manifold) to the wellhead (i.e. Well 1). This wellhead pressure and temperature was then used by a Prosper well model to model the bottom hole pressure and temperature at the top perforation.

The changes in pressure and temperature throughout this injection process are illustrated in the CO_2 phase envelope below *Figure 7-3 Quest CO_2 phase changes expected from surface compressor outlet to injector bottom hole conditions*, which shows CO_2 remaining in the liquid or supercritical phase at all times. The arrows in the phase envelope indicate the direction of flow from the compressor, through the pipelines to the wellheads, down the wellbore and into the reservoir.

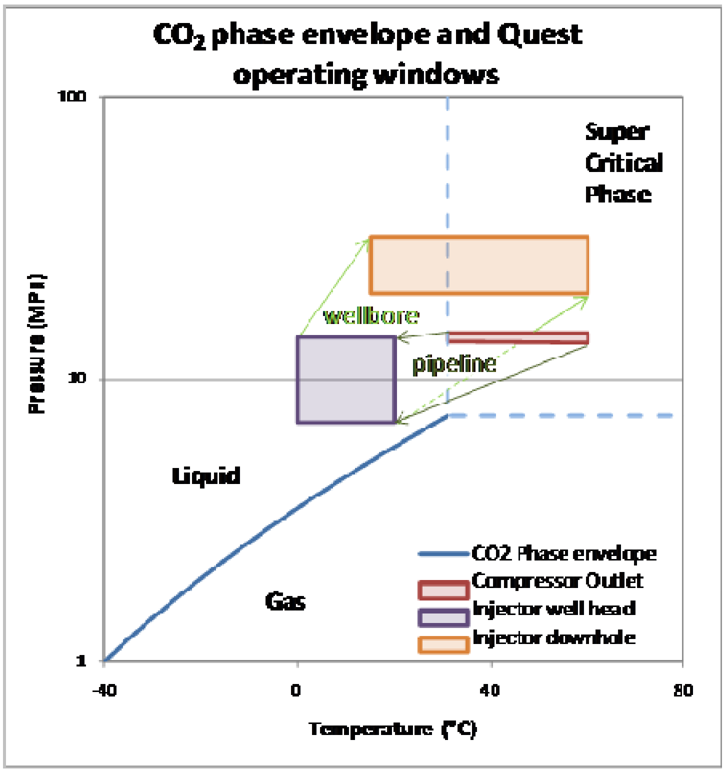


Figure 7-3 Quest CO2 phase changes expected from surface compressor outlet to injector bottom hole conditions

The following scenario's were evaluated to ensure that a 14.5 MPa compressor could deliver sufficient injection pressures in each of these surface scenarios, for the low case reservoir permeability of 20-50 mD:

- A four and five well count scenario was compared against a 10, 12, and 16 inch nominal pipeline size.
- A seven well count scenario with a 10 inch NPS pipeline was compared against 3.5" and 4.5" tubing.
- A winter and summer scenario for a 31°C and 60°C compressor discharge temperature were modelled to capture the range of realistic temperature losses attainable from the compressor to the wellhead.

GAP modelling shows a 14.5 MPa compressor discharge pressure is more than adequate to provide the necessary wellhead and bottomhole pressures to inject the minimum 1.2 Mtpa CO2 required for the Quest CCS project for all the surface scenarios modelled.

Whilst a 10" pipeline would provide adequate capacity, the decision was made to move forward with a 12 inch pipeline in the base case. This permits additional capacity to be added to the system at a later date should the opportunity arise.

The detailed results of this study can be found in the "Quest IPSM Compressor Design Modelling Results" report number EP2010-3175 [Ref 7.1].

7.3. Flow assurance

This section covers at a high-level the Flow Assurance aspects related to the pipeline and the wells, that consisted of several studies and simulations performed to identify, quantify and mitigate any potential flow assurance issues.

7.3.1. Flow Assurance Scope for the Project

The following items were studied by the flow assurance team:

- System Design
  - Pipeline
    - Thermal-hydraulic performance
    - Pipeline sizing
    - Maximum system capacity
    - Insulation requirements
    - Vent-valve design
    - Requirements for above-ground sections
  - Wells
    - Pressure-temperature in the wellbore with varying flowrate and injection temperature
    - Cooling at the well choke
    - SC-SSSV location
- Solid Disposition Risk
  - Hydrate risk and mitigation in pipeline and wells
  - Dehydratation limits
  - Solids in the injection stream
  - Impact of carryovers
- Multiphase Flow
  - Two-phase flow in pipeline and wellbore
  - Slugging screening
- Operability
  - Normal operations
  - Low flow events
  - Emergency pipeline leak / blowdown
  - Emergency wellbore blowout
  - System start-up
  - Vent line operability
  - Liquid hammer screening
  - Low water content operability

- Modeling
    - Impact of impurities
    - Applicability of simulators

Each of these elements can be found in the different Flow Assurance presentations and reports issued by SGS Houston [Ref. 7.2, 7.3, 7.4, 7.5, 7.6, 7.7, 7.8]. A specific note on the pipeline hydrate risk was also issued [Ref. 7.9 and Appendix 4].

The first part of the Flow Assurance study was to support the sizing of the system (pipeline and wells) and confirm the performance of the pipeline following the design based on IPSM. The second part of the Flow Assurance study was to simulate all operational scenarios using OLGA® (steady-state injection, start-up, low flow injection, shut-in, leak,...) and identify the potential issues, safety critical or operational, and recommend mitigation measures.

For a matter of clarity, only the strategy related to the main flow assurance risks are developed in the next section.

7.3.2. Flow Assurance Mitigation Strategy

7.3.2.1. One-phase requirement

The first main element of the flow assurance study was to investigate the impact of two-phase CO2 in the pipeline and wells. It was concluded that one-phase CO2 was a requirement in the pipeline for the following reasons:

- Two-phase CO2 can induce slugging which can give pressure and temperature instability in the system, in particular at the well choke
- One-phase CO2 maximise fluid density and minimize fluid viscosity, therefore optimising pipeline transportability
- The metering system on each wellpad loses accuracy to +/-20% which is unacceptable because of the metering requirement and the fact that unlike most projects the meter at the wellhead is the custody transfer meter for a CCS project as credits are issued at the point of storage.
- Single phase liquid CO2 will prevent hydrates from forming at any temperature

With the inclusion of online CO2 analysers within the Capture scope assuring CO2 purity, the minimum operating pressure of the pipeline is 8.5 MPa.

7.3.2.2. Hydrates mitigation

Another key identified flow assurance risk is related to the hydrate formation in the injection stream.

- *Pipeline:* the risk of hydrate formation in the pipeline during steady-state, low flow and shut-in conditions was studied and the dehydratation requirements to mitigate hydrate formation was determined and implemented (6 lbs/MMscf in summer to 4 lbs/MMscf in winter)

- *Well:* despite the large pressure drop across the well choke that generates significant cooling, simulations have shown that over the operating envelope of the integrated system, the well choke should always be outside of the hydrate formation zone, considering the dehydration requirements mentioned above. Temporary methanol injection upstream of the well choke is an additional mitigation strategy that was included in the well surface kit design.

7.3.2.3. Pipeline pressurisation and blowdown

The last main element of the flow assurance study was to look into pipeline pressurisation and controlled blowdown of parts of the system to ensure that the resulting cooling did not induce safety risks related to the minimum temperature rating of the equipment.

As per the model it will take some 96hrs to pressurize the pipeline to reach the minimum operating pressure, it is not an intuitive process, for the first 20 hours, the pipeline pressurizes until reaching the 2-phase region. Then, for the next 40 hours, the pressure and temperature both rise. What is happening is that the CO2 in the pipeline must condense and thus releasing heat. This heat is absorbed by the CO2 causing the temperature to rise even above the compressor temperature at the inlet. For about 16 hours, the pressure plateaus. The condensation at this point is complete and the liquid in the pipeline starts to cool. Due to the strong density dependence with temperature, the inflow is only compensating for the reduction in volume due to cooling. Finally, at about 96 hours, the pressure starts to quickly rise.

During venting as consequence of J-T effect, the pipeline could reach extremely low temperature if the venting rate is not controlled. To prevent reaching temperatures lower than -45degC, it was determined that vent's valve size orifice must not exceed 4inches diameter. Topography also has its effect on venting, as CO2 in dense and liquid phase tent to accumulate at the low points of the line, it is recommended to vent any segment of the line from both ends to allow a more uniform temperature gradient along the segment.

7.4. Integrated System Operating Envelope

Table 7-3 below summarises the integrated system operating envelope. This is the base design premise across all aspects of the Quest Project.

	Minimum	Maximum	Comments
Pipeline Pressure	8.5 MPa	12.9 MPa	Minimum pressure requirement is to keep CO2 in single phase in the pipeline. Maximum pressure to ensure target injection rate. Pipeline is rated for 14.79 MPa.
Pipeline Inlet Temperature	43 degC	60 degC	The minimum temperature is also the normal operational temperature.

Pipeline flowrate	0 Mtpa	1.2 Mtpa	Pipeline designed for 3.4 Mtpa but will be operated at 1.2 Mtpa maximum.
Wellhead Pressure	3.5 MPa	12 MPa	Minimum pressure defined for high case reservoir and low temperature CO2. Maximum pressure defined to achieve target injection rate at high temperature CO2.
Downhole Well Pressure	20 MPa	28 MPa	Minimum pressure is the initial BCS pressure. Maximum pressure is the maximum allowable injection pressure.
Wellhead temperature	-10 degC	26 degC	CO2 temperature range considering maximum CO2 cooling down in the pipeline and maximum pressure drop across the well choke.
Downhole temperature	15 degC	60 degC	Minimum downhole temperature is with -10 degC CO2 at wellhead and maximum injection rate. Maximum temperature is initial BCS temperature.
Well flowrate	0 Mtpa	0.6 Mtpa	Wells designed for more than 1.2 Mtpa but will be operated at 0.6 Mtpa maximum (5-well base case)
CO2 purity	95%	99.2%	CO2 purity impacts on the minimum pressure required to keep single phase flow in the pipeline. Main contaminant is H2. Normal operating purity is 99.2%.
Water content	4 lbs/MMscf	6 lbs/MMscf	The minimum and maximum water content are in winter and summer time respectively. Range is defined to mitigate risks of hydrate formation in the pipeline and the wells.

Table 7-3 Integrated System Operating Envelope

8. CONTAINMENT, STORAGE CAPACITY, INJECTIVITY AND CONFORMANCE

8.1. Geological framework

8.1.1. The BCS storage complex

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 *(Figure 8-1 Stratigraphy and Hydrostratigraphy of Southern and Central Alberta)*.

The BCS storage complex includes, in ascending stratigraphic order:

- Precambrian granite basement unconformably underlying the Basal Cambrian Sands
- Basal Cambrian Sands of the Basal Sandstone Formation – the CO2 injection zone
- Lower Marine Sand of the Earlie Formation – a transitional heterogeneous clastic interval between the BCS and overlying Middle Cambrian Shale
- Middle Cambrian Shale of the Deadwood Formation – thick shale representing the first major regional seal above the BCS
- Upper Marine Siltstone (UMS) likely Upper Deadwood Formation – progradational package of siliciclastic material made up of predominantly green shale with minor silts and sands
- Devonian Red Beds – fine-grained siliciclastics predominantly composed of shale
- Lotsberg Salts – Lower and Upper Lotsberg Salts represent the second and third (ultimate) seals, respectively, and aquiclude to the BCS storage complex. These salt packages are predominantly composed of 100% halite with minor shale laminae. They are separated from each other by 50 m of additional Devonian Red Beds.

The rocks that comprise the BCS storage complex in the CO2 storage AOI were deposited during the Middle Cambrian to Early Devonian directly atop the Precambrian basement. The erosional unconformity between the Cambrian sequence and the Precambrian represents approximately 1.5 billion years of Earth history. Erosion of the Precambrian surface during this interval likely resulted in a relatively smooth but occasionally rugose gently southwest dipping (<1 degree) top Precambrian surface. Within the CO2 storage AOI, the Cambrian clastic packages pinch out towards the northeast, while the Devonian salt seals thicken towards the northeast. For a cross-section of the WCSB showing the regionally connected BCS storage complex in relation to regional baffles and sealing overburden, *Figure 8-2 Cross-Section of the WCSB Showing the BCS Injection Zone.*

The CO2 storage AOI is within a tectonically quiet area; no faults crosscutting the regional seals were identified in 2D or 3D seismic data.

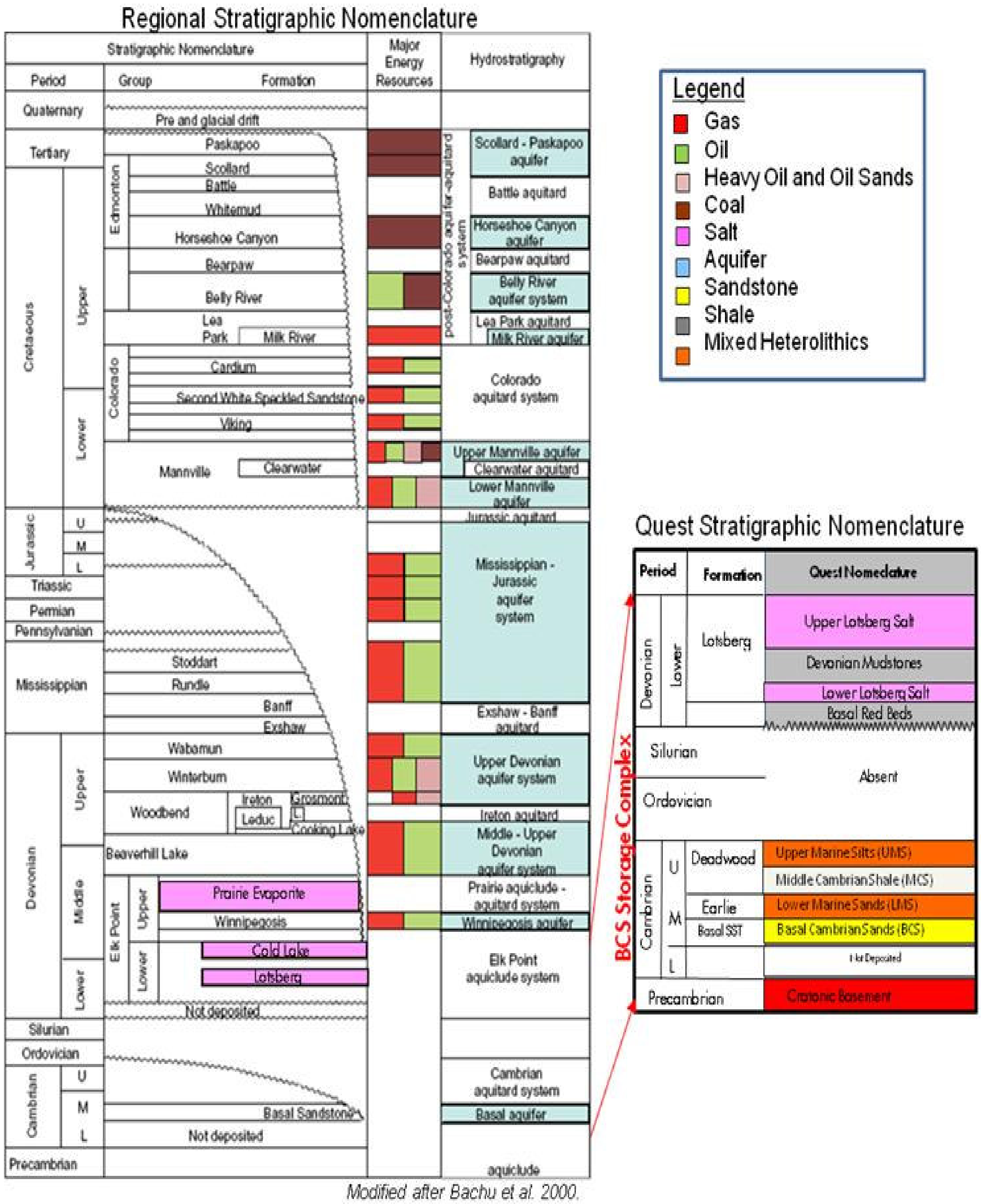


Figure 8-1 Stratigraphy and Hydrostratigraphy of Southern and Central Alberta

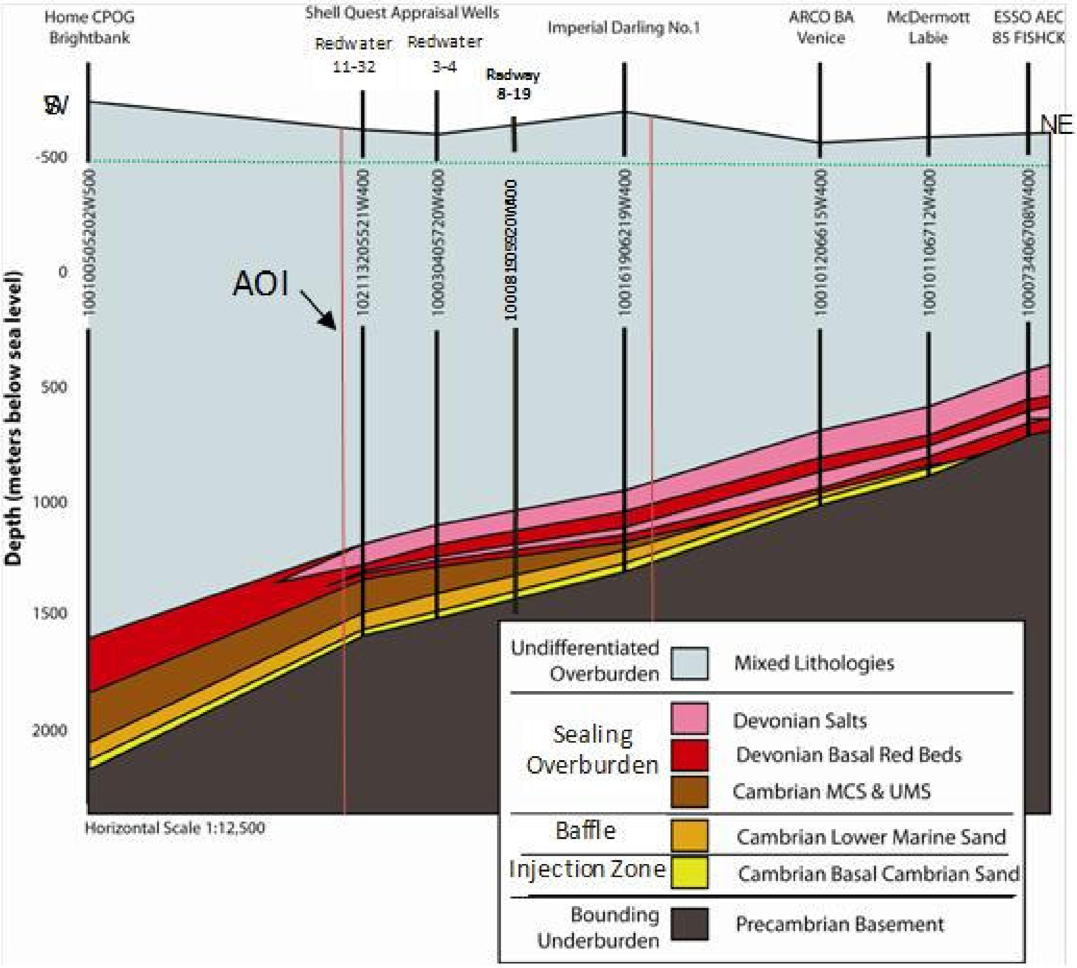


Figure 8-2 Cross-Section of the WCSB Showing the BCS Injection Zone

8.1.2. Geology of the BCS CO_2 Injection Zone

The following is an overview of the Basal Sandstone Formation, which represents the only Quest CO2 injection zone. For a more detailed description of the Cambrian interval of interest including the Basal Sandstone Formation see the Quest Gen-4 Integrated Reservoir Modeling Report [Ref 8.2]. The Basal Sandstone Formation lies unconformably on Precambrian age crystalline basement and is principally composed of fine to coarse-grained sandstone with minor clay to silt-sized intercalations. While this formation is widespread beneath much of the Alberta Plains, rare thin-to-absent sections exist where Precambrian highs, likely related to basement block boundaries, precluded deposition.

Appraisal well core data and available Cambrian literature suggest that BCS sediments were deposited in a shallow marine tide-dominated bay margin (TDBM) environment that was created as a broad antecedent topographic low on the Precambrian craton that was flooded during a global sea level transgression. Sediments deposited in a TDBM environment are typically reworked many times over into sub-tidal dunes, inter-dunes, and high energy dune sand bodies; the latter of which most frequently accumulate near shore in tidal channels as dendritic extensions of the existing riverine network. This system manifests in the rock record as a fining upward sequence in which the coarsest sands and best reservoir quality material is typically focused at the base of the section; a relationship confirmed for the BCS in the AOI for the first time via core from the third Quest appraisal well, SCL Radway 08-19-059-20 W4M (Desjardins et al., 2011). As a whole, the Basal Sandstone Formation records an exceptionally high net-to-gross (0.75-0.95) ~35 - ~50m thick "sheet sandstone" that presently acts as a basin-scale saline aquifer with no known hydrocarbon accumulations. A gradational shift to increasingly more frequent and thicker fine-grained beds marks the top of the BCS. This transition is the consequence of the continued sea level progression up the margin toward what is presently the northeast and the associated migration of BCS sand deposition. A dynamic that continuously left older down-dip BCS sediments to be buried by progressively deeper water and subsequently finer-grained sediments, and therefore ultimately created a time-transgressive contact between the BCS and the overlying LMS. [Ref 8.1, 8.2]

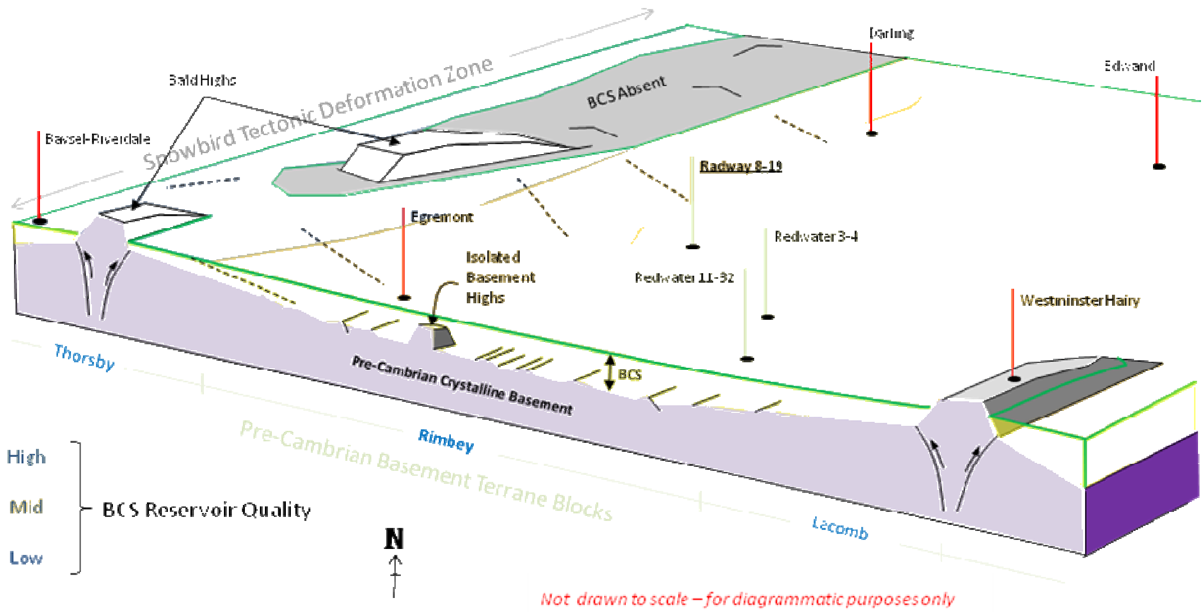


Figure 8-3 Conceptual BCS Reservoir Quality Block Model

The remainder of the BCS storage complex comprising the three seals and intermediate intervals are described in further detail in Section 8.2.1 under Containment.

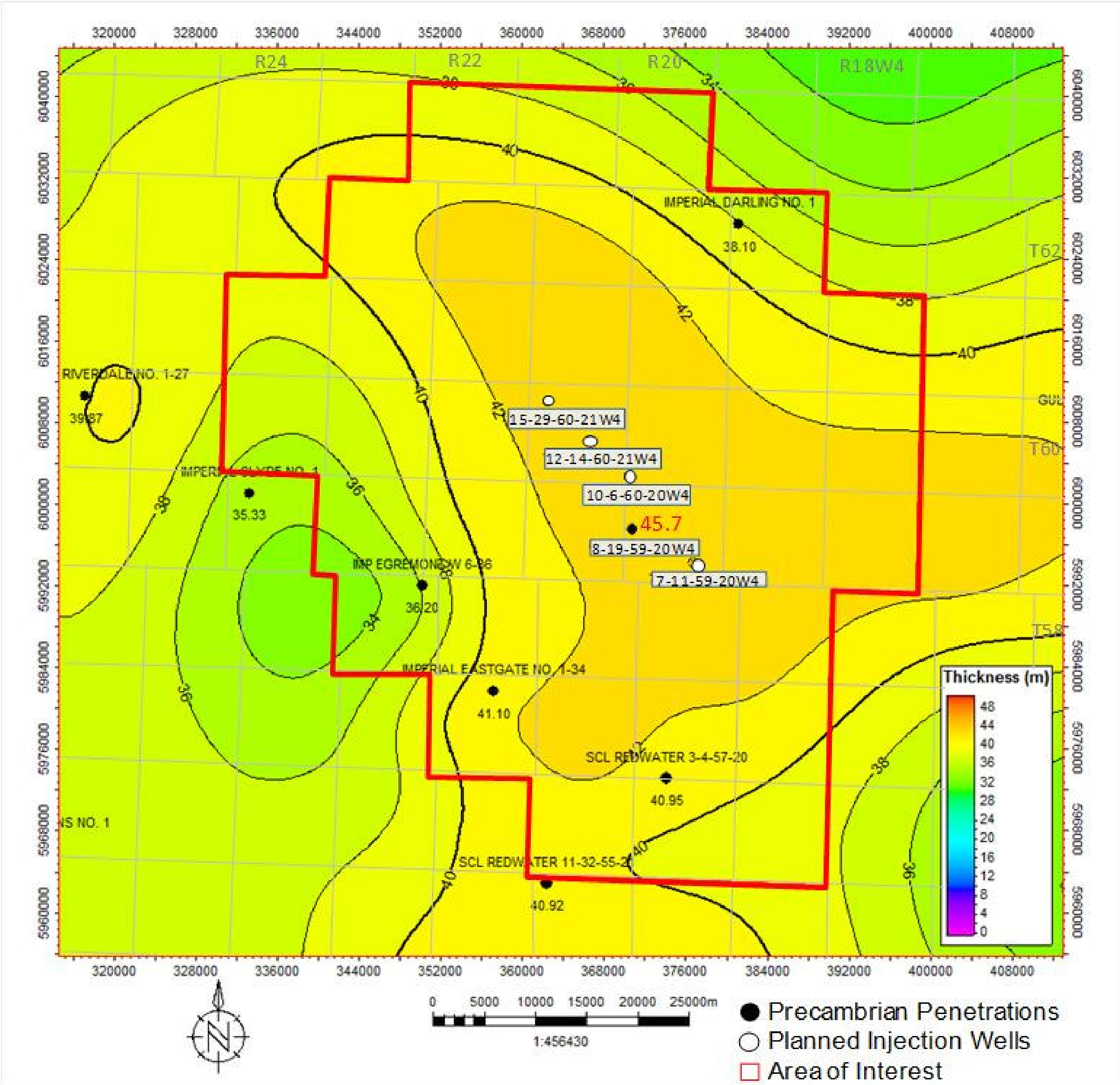


Figure 8-4 Basal Cambrian Sands - Gross Sand Thickness

8.2. Containment

8.2.1. Geology of the Bounding Formations

This section describes the nature of the stratigraphy of interest considered to prevent migration of fluids out of the BCS storage complex. The basal bounding formation to the BCS is the Precambrian basement. Above the BCS are the three major seals considered the most important for containment. Deposited between the three major seals are additional intervals that act as secondary baffles impeding the vertical migration of CO_2 up through the stratigraphic column.

In ascending stratigraphic order, the three major seals and three baffles in relation to the BCS injection zone are:

- Precambrian basement – basal bounding formation
- BCS – CO_2 injection zone
- LMS – baffle
- MCS – the first major seal
- Upper Marine Sand – baffle
- Devonian Red Beds – baffle
- Lower Lotsberg Salt – the second major seal
- Devonian Red Beds - baffle
- Upper Lotsberg Salt – the third major (ultimate) seal

Basal Seal: Precambrian Basement

The CO_2 injection zone (BCS), in the Cambrian sequence lies directly above the Precambrian basement. Seismic surveys and appraisal well FMI logs indicate the existence 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 CO_2 storage 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 CO_2 storage 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 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 CO_2 storage AOI, the MCS is the oldest formation affected by the Devonian unconformity. This yields a section that decreases from approximately 75 m in thickness in the southwest, where it is conformably overlain by the UMS and not subject to the unconformity-associated erosion, to approximately 21 m in the northeast, where it is in direct contact with Devonian strata (*Figure 8-5 Thickness and Extent of Middle Cambrian Shale over the AOI*).

The MCS is believed to be a competent seal even at the minimum thickness interpreted within the CO_2 storage 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 micro Darcy range, as interpreted from the shale and clay content described in these sands. However, the vertical permeability is interpreted to be in the nano Darcy range due to the presence of laminated bedding. No core measurements were achieved in these sand streaks.

SCAL testing of the MCS shale is ongoing including both geomechanical testing, thin section analysis and porosity and permeability measurements. The results will be documented in the Seal Integrity Report when complete [Ref 8.3].

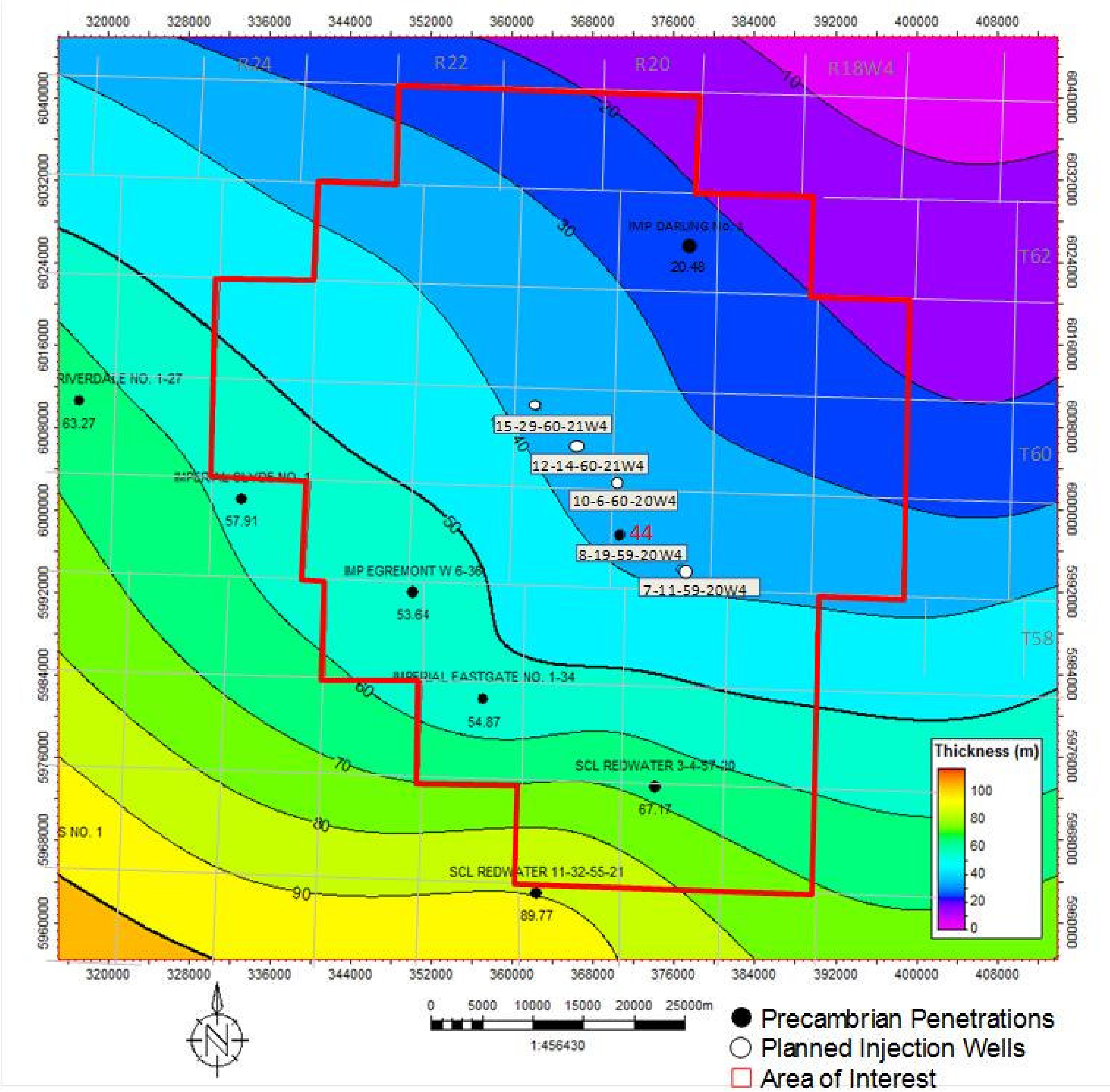


Figure 8-5 Thickness and Extent of Middle Cambrian Shale over the AOI (Gen3)

Baffle: Upper Marine Sands likely of the Upper Deadwood Fm

The UMS lies above the MCS, which is the first major seal to the BCS storage complex. The Upper Cambrian UMS is only evident in the southwest portion of the CO_2 storage 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, and virtually no vertical connectivity was interpreted, consistent with the poor horizontal properties seen in logs.

Baffle: Devonian Red Beds

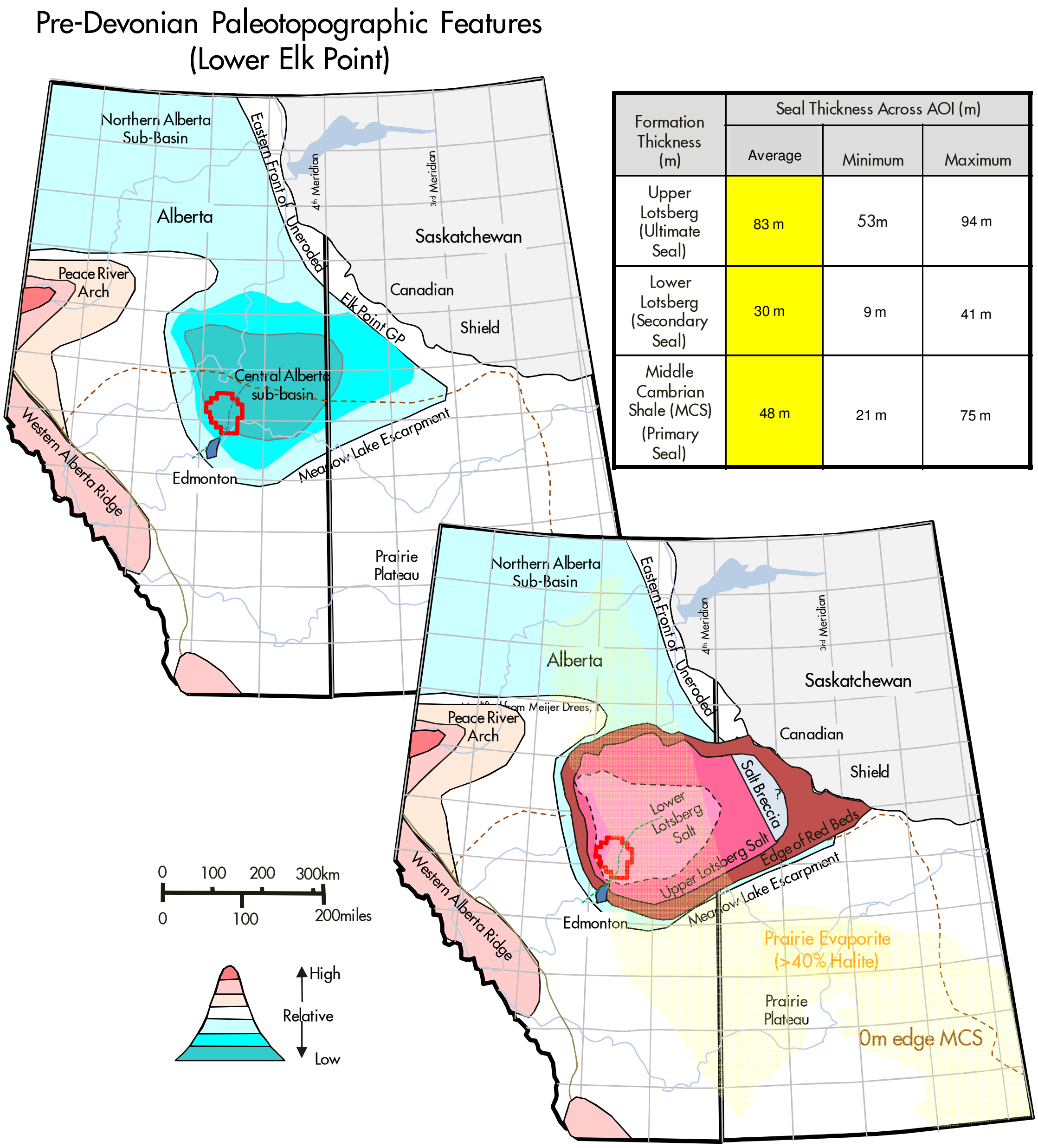
Directly overlying the Cambrian UMS are Devonian Elk Point Group fine-grained siliciclastics and evaporites. The Devonian unconformity, which separates the Cambrian and Devonian sequences, represents approximately 100 million years. The Cambrian sedimentary sequence was typified by a passive continental 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 Devonian Red Beds are confined to the Central Alberta Sub Basin and are characterized by thin shaly intervals that merge at the basin margins with other Devonian red beds. The Devonian Red Beds are composed of brick red dolomitic or calcareous silty shalethat grade downward to red sandy shale. The Red Beds have sometimes been described as lagoon or bay deposits. 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 Third (Ultimate) Seal: Lotsberg Formation

Overlying the Devonian Red Beds is the Devonian Lotsberg Formation, consisting of the Lower and Upper Lotsberg salts, separated by a layer of fine-grained siliciclastics, deposited during periods of relative basin isolation and subsequent evaporite formation. The salts are almost pure halite with minor shale laminae, and represent the second and ultimate seals for the BCS storage complex, respectively. The Lotsberg salts are true aquicludes, with their large lateral extent, thickness, impermeability and ability to anneal via plastic deformation. The Upper Lotsberg 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 salt units 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. The Lower Lotsberg is thin (~9 m) in the Western portion of the AOI but thickens to 41m in the northeast (*Figure 8-7 Extent and Thickness of the Lower Lotsberg Salts in the AOI*). The Upper Lotsberg is a true aquiclude present over the entire AOI and varies in thickness from approximately 55 m in the west to 94 m in the northeast of the AOI (*Figure 8-8 Extent and Thickness of the Upper Lotsberg Salts in the AOI)*.

Further information on the Sealing capacity of the Lotsberg salts can be found in the Seal Integrity Report [Ref 8.3].



Formation Thickness (m)	Seal Thickness Across AOI (m)		
	Average	Minimum	Maximum
Upper Lotsberg (Ultimate Seal)	83 m	53m	94 m
Lower Lotsberg (Secondary Seal)	30 m	9 m	41 m
Middle Cambrian Shale (MCS) (Primary Seal)	48 m	21 m	75 m

SOURCE: Modified from N.C. Meijer-Drees, 1994. Geological Atlas of the Western Canada Sedimentary Basin.

Figure 8-6 Regional Extent of the Middle Cambrian Shale, the Lower and Upper Lotsberg Salts and the Prairie Evaporites

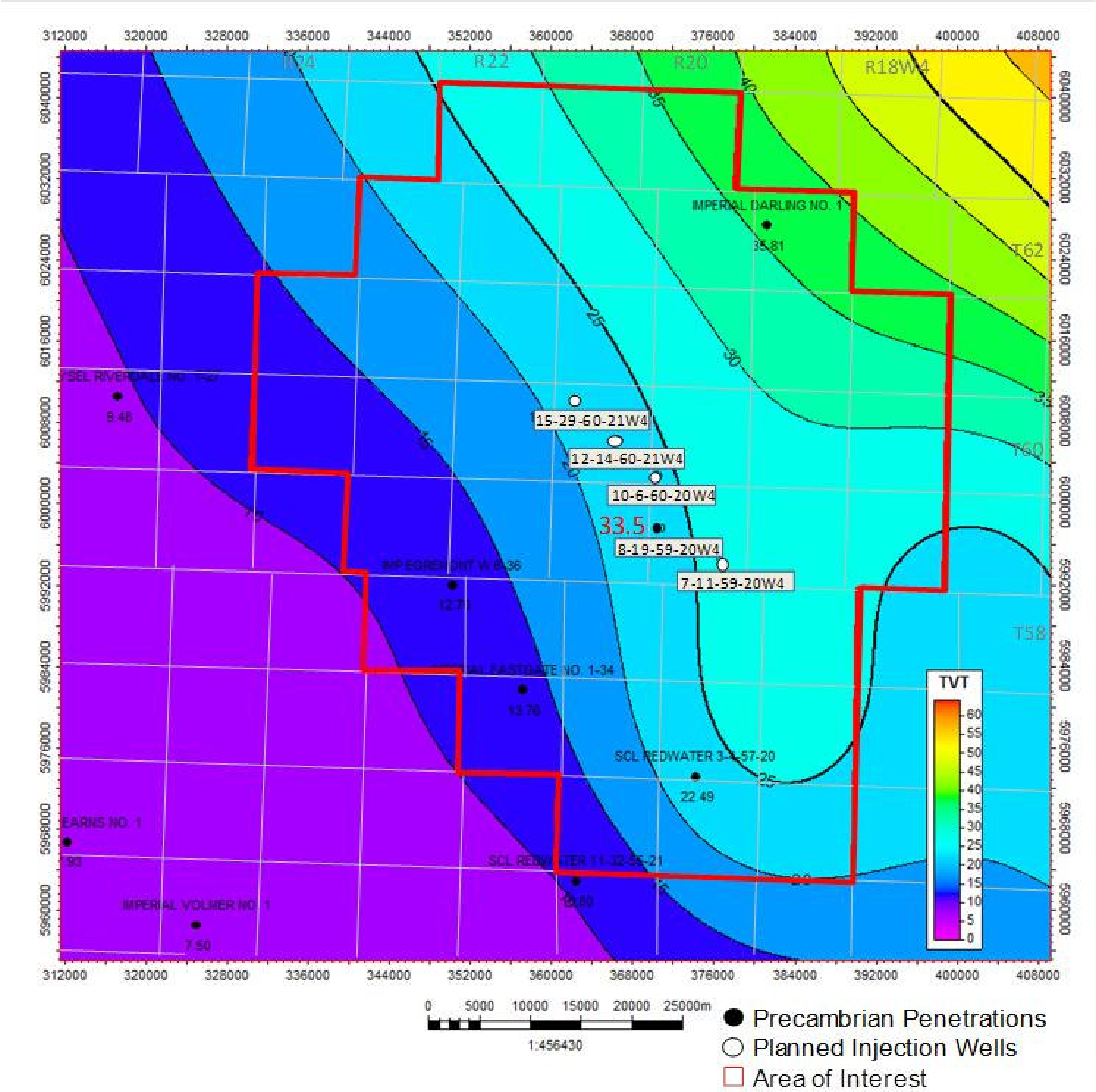


Figure 8-7 Extent and Thickness of the Lower Lotsberg Salts in the AOI

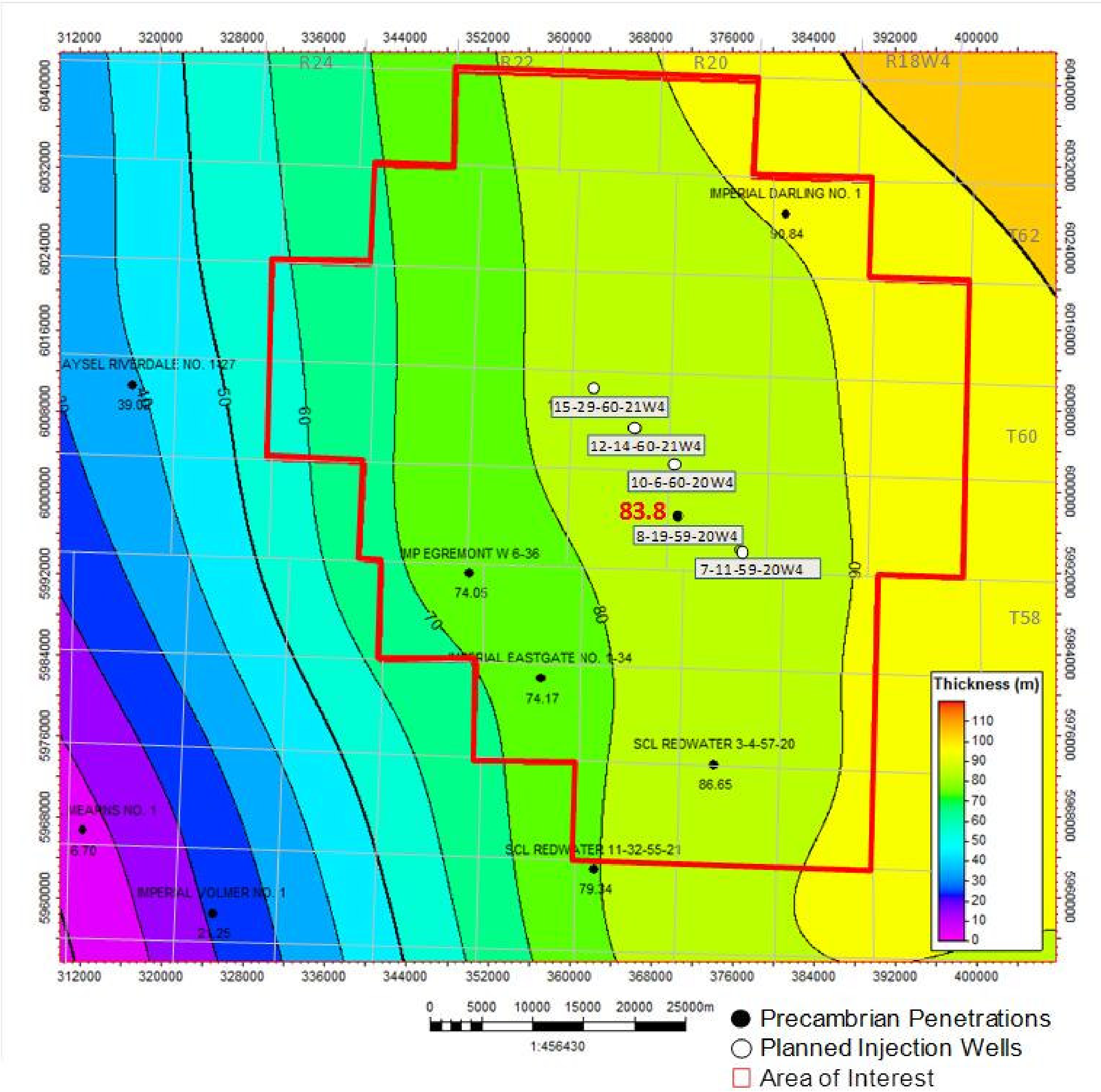


Figure 8-8 Extent and Thickness of the Upper Lotsberg Salts in the AOI

8.2.2. Containment bowtie

The application of the Bow Tie process to assess barriers that reduce containment risk to ALARP (As Low As Reasonably Practicable) is a key process in the development of a risk based, site specific MMV plan [Ref 10.1].

The containment Bow Tie that describes the threats and consequences of a Loss of Containment event is provided in *Figure 8-9 Containment Bow-tie for the Quest Project* on the next page. The top event in this bow-tie is defined as "Migration of CO2 or BCS brine above the Upper Lotsberg

Salt" (Ultimate seal for the BCS storage complex). All threats on the left side of the bow-tie are captured in the Quest EasyRisk database and are aligned with Risk hypotheses in TESLA.

The bow-tie is an integral part of the Quest risk management framework and is used to support the MMV objectives around ensuring containment. This subset of overall MMV objectives focuses on:

- Detect early warning signs for any loss of containment
- Activate safeguards to reduce containment risks to ALARP
- Demonstrate effectiveness of any control measures deployed

The Risk based Management Approach to MMV comprises:

- An iterative evaluation cycle to Identify-Monitor-Decide-Respond to each Risk Outcome
- The use of a Bowtie for safety critical risk: Containment
- Selection of MMV options based on technical feasibility & Value of Information
- An adaptive MMV plan to manage lifecycle risks

The threat of migration along a Quest well was broken down further to the various elements and failure mechanisms in the well that could result in loss of containment. The wells bow tie is provided in *Figure 8-10 Wells Bow-tie, subset of the Containment Bow-tie for the Quest Project* and applies equally to Quest injection and MMV wells if they would be required to penetrate the seals of the BCS storage complex.

The five threats on the left hand side of the wells bow-tie were also entered into the Quest risk database and complement the 8 threats from the containment bow tie on the previous page.

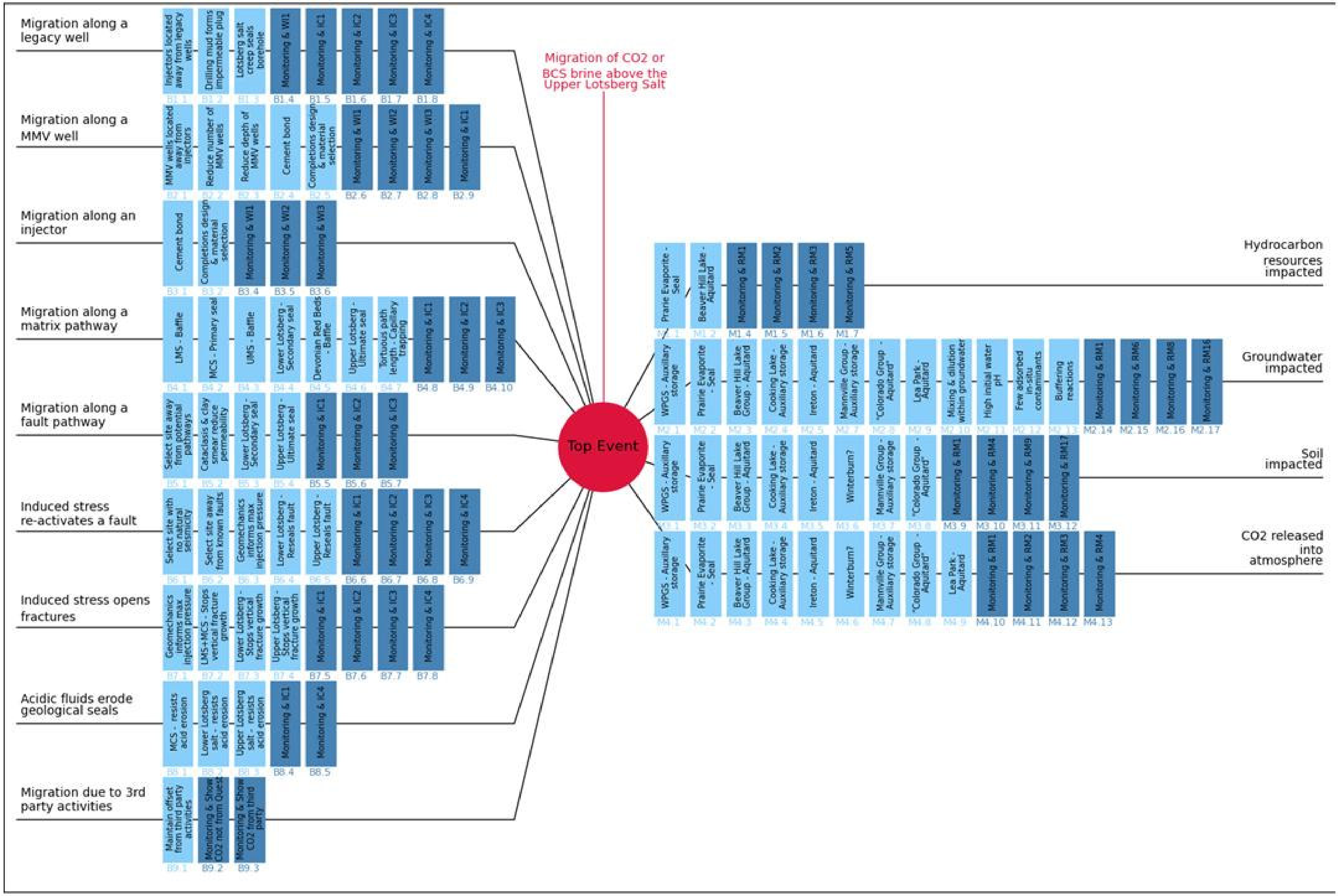


Figure 8-9 Containment Bow-tie for the Quest Project

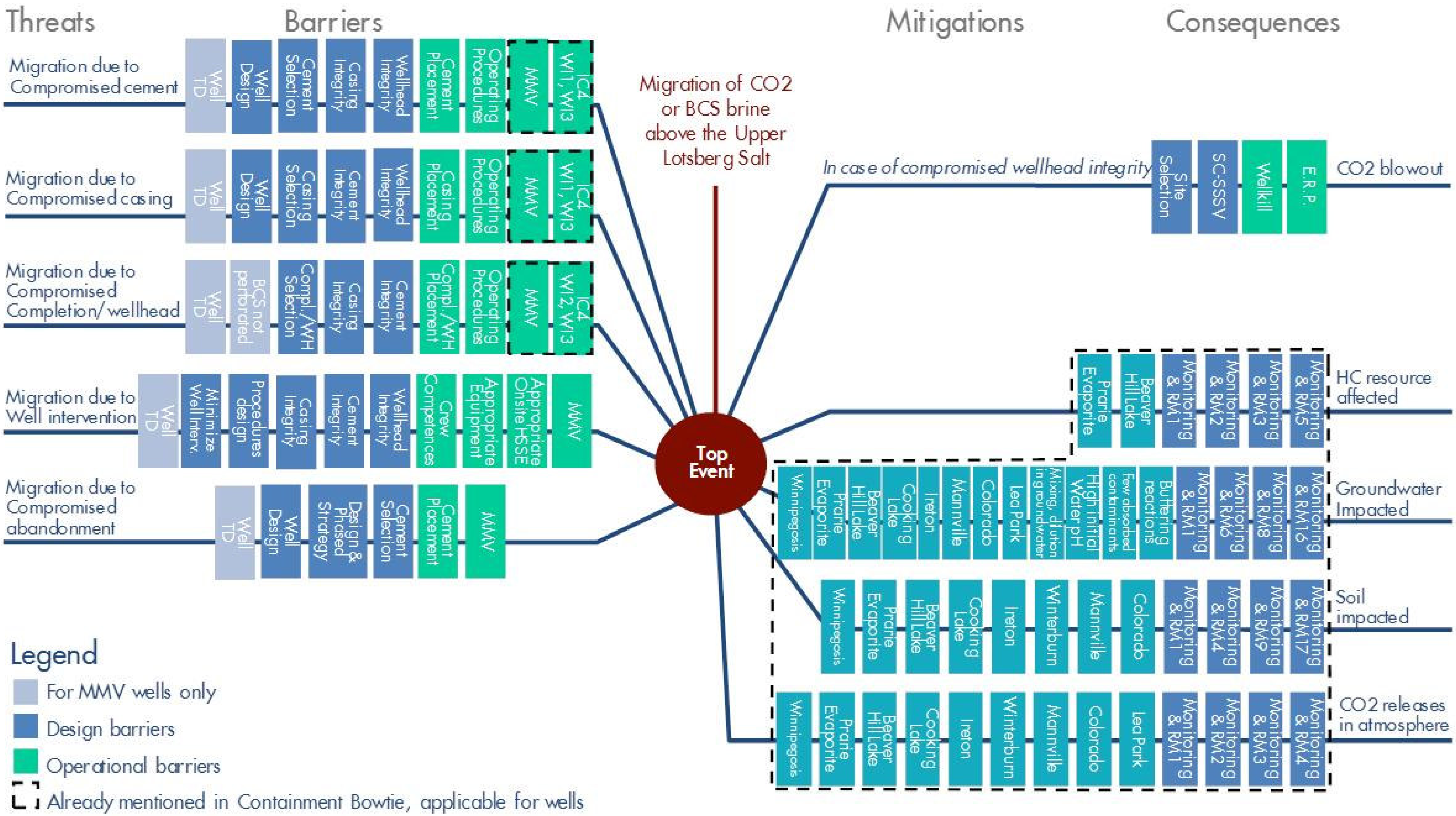


Figure 8-10 Wells Bow-tie, subset of the Containment Bow-tie for the Quest Project

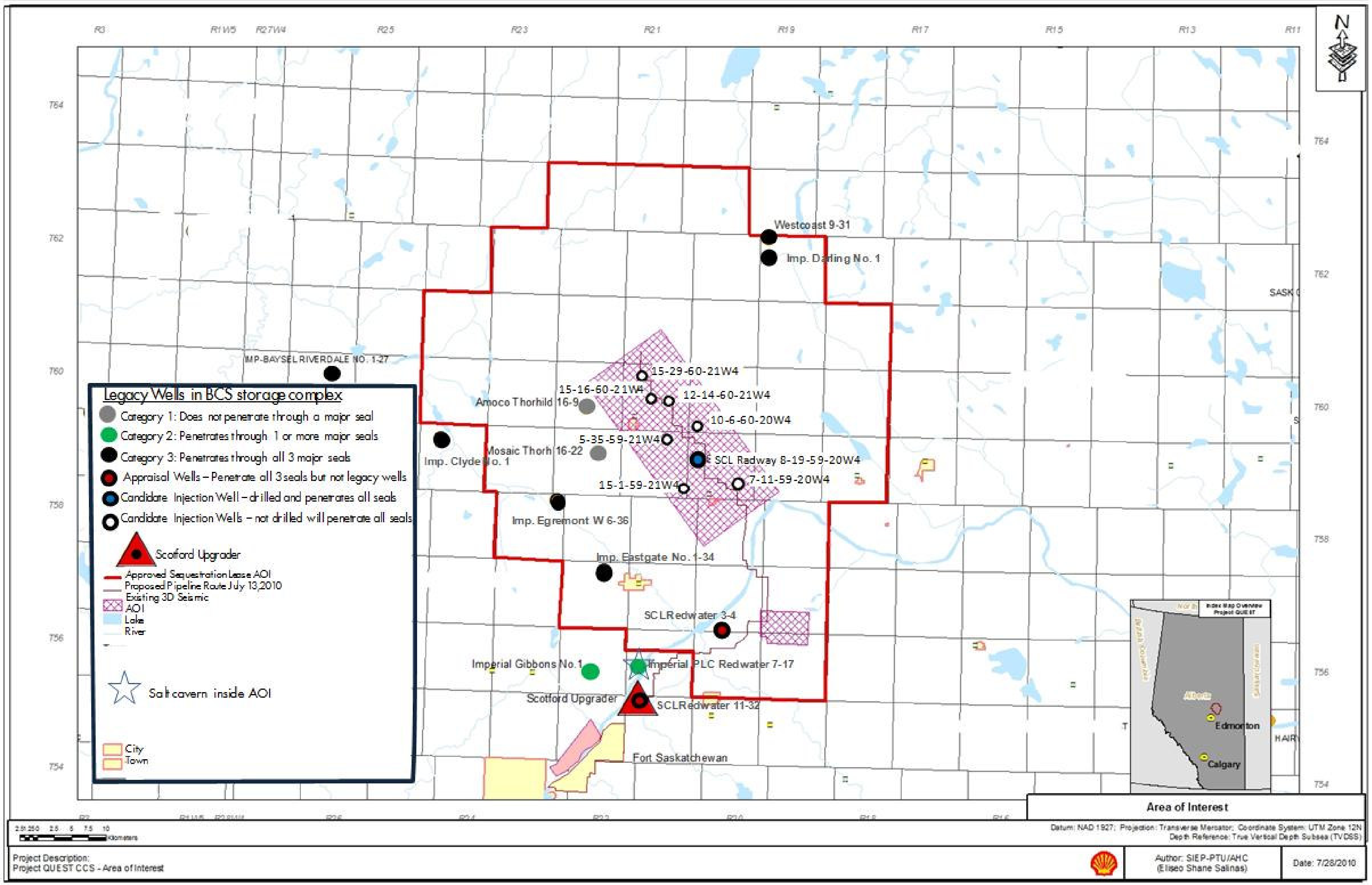


Figure 8-11 Map View of Legacy Wells Penetrating the BCS Storage Complex. Only wells within or in close proximity to the AOI are shown.

8.2.3. Site specific risks to containment

The site specific risks to containment will be addressed in the order they appear in the containment bow-tie in *Figure 8-9 Containment Bow-tie for the Quest Project* in the sections below.

8.2.3.1. Migration along a legacy well

The status and condition of existing wells penetrating the BCS has now been reviewed from multiple data sources. There are no known issues with legacy well integrity other than the uncertainty that arises from the age of the cement plugs and the inability to pressure test these old cement plugs.

The following mitigations were implemented during site selection to minimize this risk:

1) selection of an AOI with few BCS penetrations
2) selection of an injection site within the AOI to maximize the offset to legacy wells (21 km from Radway to Egremont downdip, 31 k from Radway to Darling updip).

The following barriers are in place in the known legacy wells:

1) multiple cement plugs of significant length at various intervals
2) open hole abandonment across the salt allows for the opportunity for hole closure by salt creep
3) impermeable plugs may have formed through settlement of solids out of drilling mud in well bore

The legacy well study was extended to all wells penetrating the Upper and Lower Lotsberg salts to evaluate the risk of a leak path above the BCS storage complex [Ref 8.4]. Two independent data searches have been completed to ensure all legacy wells have been included:

1) The initial search was using Accumap, a system provided with data by IHS
2) a second independent search of publicly available databases to ensure no legacy wells penetrating the BCS storage complex had been missed was completed on Geovista, a system that acquire its data from Divestco. No additional wells were found.

The Carbon Sequestration Lease, approved on 27 May 2011, contains four third-party legacy wells within its boundaries, *Figure 8-11 Map View of Legacy Wells Penetrating the BCS Storage Complex.*:

1) Egremont W6-36,
2) Imperial Eastgate 1-34,
3) Imperial Darling No.1
4) Westcoast et al Newbrook 9-31(Westcoast 9-31)

5) The PLC Redwater 7-17 well, an abandoned salt cavern, is no longer part of the AOI as the 24 most southwesterly sections (Sections 1-24 in Township 56-21W4) submitted in the Sequestration Lease Application were excluded by the ERCB in the approved Carbon Sequestration Lease Tenure.

Abandonment reports are available for the four third-party legacy wells in the AOI that penetrate the three seals in the BCS storage complex, as well as for the following third-party legacy well penetrations in the vicinity of the AOI boundary that penetrate through one or more seals in the BCS storage complex:

- Imperial Baysel Riverdale No. 1-27
- Imperial Clyde No.1
- Imperial Gibbons No. 1
- Imperial PLC Redwater 7-17
- Four salt cavern wells: Provident 12, 14, 15 and 16

The current status of the legacy wells inside the original AOI are summarized in *Table 8-1 Abandonment Status of Third Party Legacy Wells Inside the AOI*

The biggest remaining uncertainty is around the status of Legacy well Imperial Darling as this well is inside the AOI but was not cemented across the seals of the BCS storage complex. Imperial Clyde has a very similar abandonment status, lacking a cement plug over the seal of the BCS storage complex. A full summary of the abandonment status for all the relevant third-party legacy wells stated above is provided in [Ref 8.4] and summarized in *Table 8-1 Abandonment Status of Third Party Legacy Wells Inside the AOI.*

Theoretical threshold pressures were calculated for each of the third-party Legacy wells that drill through the MCS seal in the AOI to see at what BCS pressure there could be a risk of lifting BCS brine into the base of the groundwater protection zone (BGWP) are summarised in *Table 8-2 Pressure Increase Required to Lift BCS Brine to the BGP in an Open Conduit*

Table 8-1 Abandonment Status of Third Party Legacy Wells Inside the AOI

Well name and UWI	History	Seals Penetrated	Casings and holes	Cement plugs
Imperial Eastgate 100-01-34-057-22W400	- Drilled and abandoned in 1955	- Upper Lotsberg - Lower Lotsberg - MCS	- 9 5/8" casing to 277m - 9" openhole to 2205m (TD)	#1: 265 – 289 m #2: 644 – 710m #3: 887 – 981m #4: 1016 – 1048m #5: 1256 – 1292m #6: 2125 – 2205m
Imperial Egremont 100-06-36-058-23W400	- Drilled and abandoned in 1952	- Upper Lotsberg - Lower Lotsberg - MCS	- 13 3/8" casing to 186m - 9" openhole to 2242.3m	#1: 172 – 195m #2: 624 – 670m #3: 844 – 875m #4: 969 – 1003m #5: 1178 – 1218m #6: 2140 – 2242m
Imperial Darling #1 100-16-19-062-19W400	- Drilled and abandoned in 1949	- Upper Lotsberg - Lower Lotsberg - MCS	- 13 3/8" casing to 183m - 9" (supposed) openhole to 2013m	#1: 168 – 198m #2: 525 – 587m #3: 708 – 740m #4: 762 – 792m
Westcoast et al Newbrook 100-09-31-062-19W400	- Drilled in and abandoned in 1978	- Upper Lotsberg - Lower Lotsberg - MCS	- 9 5/8" casing to 230m - 7" (supposed) openhole to TD at 1923m	#1: 183 – 366m #2: 518 – 701m #3: 838 – 960m #4: 1082 – 1204m #5: 1280 – 1402m #6: 1524 – 1615m #7: 1707 – 1923m
Imperial PLC Redwater LPGS 100-07-17-056-21W400	- Drilled in 1974 - Converted to LPG reproducer in 1975 - Abandoned in 2007	- Upper Lotsberg	- 13 3/8"casing to 188.4m - 9 5/8" casing to 1778.2m - 7" casing to 1836m - TD at 1861m	#1: 0 – 500m #2: 1435 – 1760m #3: 1760 – 1861m

Table 8-2 Pressure Increase Required to Lift BCS Brine to the BGP in an Open Conduit

Well Name	Surface elevation (mBSL)	BGP depth (mBSL)	Hydrostatic pressure at BGP (kPaa)	Extrapolated BCS pressure at BGP (kPaa)	Delta P (kPa)
Imperial Eastgate No. 1-34	-641.3	-401	2,456	996	3,452
Imperial Egremont W 6-36	-627.9	-408	2,259	1,175	3,334
Imperial Darling No. 1	-704.4	-469	2,406	1,795	4,201
Westcoast 9-31	-699	-471	2,338	1,808	4,146
NOTE: mBSL – metres below sea level					

The probability of legacy wells being intersected by the plume or pressures high enough to lift BCS into the groundwater is very low as most of them are outside the AOI with only four penetrations through the MCS seal inside but towards the boundaries of the AOI away from the central injection area.

The proposed MMV plan provides additional options for early warning through pressure monitoring (e.g. InSAR, with a BCS pressure calibration point at Redwater 3-4).

A conceptual radial leak path model was built for Imperial Darling No. 1 as this well has the shallowest abandonment plug and is the only legacy well in the AOI that does not have cement across the seals of the BCS storage complex. This type of modeling confirms findings from hydrogeological contamination modeling in the groundwater, suggesting:

1) the radius of potential contamination with saline brine is limited to <100m.
2) The pressure signal, in the event of brine migration through the abandoned well bore, responds faster and has a larger radius of penetration, easily exceeding 500m (assuming reservoir continuity).
3) Both the Winnipegosis and the Cooking Lake aquifers appear to be suitable candidates for pressure monitoring if reservoir continuity for these reservoirs can be confirmed.

In addition it shows that brine contamination would probably never reach the groundwater due to the Cooking Lake acting as a pressure sink as it has the lowest formation pressure gradient in the entire sequence from BCS to surface.

8.2.3.2. Migration along a MMV well

The base Storage Development Plan does not include the addition of dedicated BCS MMV observation well penetrations for the following reasons:

1) The selected MMV technologies of 4D seismic and InSAR are expected to provide conformance information with much better areal coverage than any single well penetration can provide without the additional risk of having to penetrate the seals of the BCS storage complex.

2) The perceived benefits of additional BCS observation wells are limited because they have no ability to verify containment[ii] and are ineffective at conformance monitoring unless used in large numbers.

It is recognized that there is a risk that the regulator will not accept an MMV plan without BCS observation wells and not all non-invasive monitoring techniques have proven feasibility. However, with the exception of converting the existing Redwater 3-4 penetration into a BCS pressure observation well, the Project has no plans to drill new observation wells into the BCS for direct CO2 monitoring or otherwise.

The following mitigations are in place to address this risk:

1) The initial base case MMV Plan does not include BCS observation wells
2) The use of Redwater 3-4 as a BCS pressure observation well
3) All BCS injectors will be used as BCS observation wells:
    a. during the start-up period pressure build up and interference will be monitored
    b. the well sparing philosophy allows for regular sequence of annual fall-off tests in injection wells (to be included in the operating guidelines)
    c. during the closure period BHP will be monitored, sampling and logging are also possible.
4) InSAR, VSP and seismic are part of the initial base case MMV Plan
5) InSAR will be calibrated to BCS pressure measurements from the Redwater 3-4 BCS observation well

8.2.3.3. Migration along a injection well

Incorporation of learnings from drilling the first two appraisal wells (11-32 and 3-4), regional drilling experience, and wellbore stability and mud testing led to the third well, and first injection well (8-19), being drilled, cased and cemented with hydraulic isolation over all three seals. Drilling a gauge hole has proved critical to achieving good cement integrity over the seals of the BCS storage complex and the use of oil based mud combined with an intermediate casing setting depth just below the base of the MCS, the first seal in the complex is likely to be continued for future injection wells into the BCS.

The well risks are broken down further in the wells bow-tie (*Figure 8-10 Wells Bow-tie, subset of the Containment Bow-tie for the Quest Project*) in the below five risk groups:

1) Compromised Casing Integrity
2) Compromised Cement Integrity
3) Compromised Completion Integrity
4) Well intervention
5) Compromised Abandonment

[ii] Monitoring *inside* the storage complex provides no ability to detect fluids migrating *outside* the complex.

Chapter 9 will discuss how the various well risks are being mitigated in the well design.

8.2.3.4. Migration along a stratigraphic pathway

This risk has been substantially reduced by proving the continuity of all three seals of the BCS storage complex through 3D and 2D seismic and a central well penetration in the AOI (Radway 8-19).

The following mitigations are in place to address this risk:

1) 2D seismic covers the entire AOI with a spacing of 2-3km and shows continuity of seals
2) Every well in the AOI has confirmed the presence of all three seals.
3) Lotsberg seal thickness LL 9-41m and UL 53-94m suggest low likelihood of local gaps
4) Tortuosity of leak path as seal breaches are unlikely to align
5) Buffering effects of long leak path
6) BCS and WPGS water chemistry differences suggest long term isolation of these aquifers from each other
7) The cleanest shales are at the bottom of the MCS section and will erode last by the Devonian unconformity towards the NE

8.2.3.5. Migration along an open fault pathway

The 3D seismic data now covers approximately 415 km2 or about 11% of the AOI and the latest processed data, available since April 2011, indicate increased frequency content of the data (up to 100Hz) which for the first time allows for an interpretation of an event near the top BCS. The absence of interpreted faults continuing from top Precambrian interval to top of BCS on the 3D seismic dataset has reduced the probability of the presence of faults across the BCS reservoir or any of the seals that could act as migration paths out of the BCS storage complex.

The following mitigations are in place to address this risk:

1) Faults are picked on the Pre-Cambrian granite seismic interval.
2) Evidence of no faults with throws greater than 15 m crossing the seal complex from 2D and 3D seismic covering the full AOI. The 2D seismic spans the entire AOI with ~3 km spacing and 415 km2 of 3D seismic is available over the central development area.
3) There is a period of ~1.5 billion years between the granite and the deposition of the BCS. Therefore it is unlikely that any Pre-Cambrian faults were active in the BCS time of deposition.

4) 3D seismic will help place injection wells away from features that may represent faults at the Precambrian basement level.
5) The Lotsberg salts are ductile and expected to creep and reseal any unexpected small faults.

8.2.3.6. Induced stress reactivates a fault

In line with the very low likelihood of the presence of faults intersecting either the BCS or any of the seals in the storage complex, there is a very low likelihood of fault reactivation.

The following mitigations are in place to address this risk:

1) The Quest AOI is not an area of active natural seismicity. There is a regional seismic monitoring network in place for more than 80 years with a capability of detecting a magnitude 3 event within our AOI. None were detected over this period (Reference: AGS Tectonic activity map for Alberta).
2) No faults offsetting the MCS or Lotsberg seals were mapped in the AOI using 2D seismic that spans the entire AOI with ~3 km spacing and 415 km2 of 3D seismic over the development area.
3) 3D seismic will help place injection wells away from features that may represent faults at the Precambrian basement level.
4) The Lotsberg salts are ductile and expected to creep and reseal any unexpected small faults.
5) Compressor discharge pressure is limited to 14.5 MPa (900# pipe class)
6) Down hole gauges will be deployed to ensure that wells stay within pressure constraints using well head chokes to control pressure.
7) Under normal operating conditions injection will be distributed over n wells. The system will be designed to stay below the maximum injection pressure constraint for n-1 wells, resulting in pressures below the maximum constraint for most of the time using n wells.
8) Downhole microseismic monitoring will detect any fault reactivation within 600m of the injector to motivate a reduction in injection pressure (to be included in the final MMV plan).

8.2.3.7. Induced stress opens fractures

As discussed in section 7 Minifrac data from Redwater 11-32 and Radway 8-19 suggests good alignment of the BCS fracture extension pressure (FEP) between these wells that are 36km apart. A conservative approach has been taken by setting the BHP limitation at 28 MPa based on the weaker LMS fracture gradient and including a 4MPa safety margin to account for the reduction in fracture gradient due to the thermal impact of CO_2 injection.

8.2.3.8. Acidic fluid erodes seals

Several MCS cores were acquired in the first few Quest wells. The first seal (MCS) contains small quantities of dolomite and K-feldspar. The dissolution of these minerals in a low pH CO2 environment could be offset by the creation of clays in this reaction, resulting in a net loss of permeability, although there is uncertainty about the timing of precipitation (10 days to 10 years).

Shell was granted permission from ATCO Gas and Pipelines LTD. in March 2011, to take 9 plugs from their Upper Lotsberg core located in 100-07-34-055-21W400 (located on the southern border of the AOI) for SCAL analysis. A SCAL Program comprising the following elements in ongoing:

1) High Resolution photos of the core and the salt plugs. Including proper depth marking.
2) Thin section and petrography to determine the salt composition.
3) Salt porosity & permeability measurements to prove that the Lotsberg Salt is a competent seal.
4) Salt creep test for geomechanics
   (The last two items are now unlikely to be carried out due damage during cutting of the core plugs).

In addition, Shell will take a representative core of the Upper Lotsberg Salt in the Second CO2 injection well (100-07-11-059-20W400) to confirm that the samples used for SCAL were reasonable analogues (for more detail see Seal Integrity report [Ref.8.3] 07-3-ZG-7180-0012.

The following mitigations are in place to address the risk:

1) Thickness of seals and baffles that need to be eroded are 350m from top perfs to top ultimate seal
2) Buffering materials (mostly clay minerals) in the seals and baffles between the salt seals and the top perfs are abundant. CO2 leaking into the seals/baffles will lose moisture and acidity
3) The secondary and ultimate seals, the Upper and Lower Lotsberg salts respectively, are comprised of greater than 90% pure halite. Salt is not known to be affected by the acidity of the formation brine. The BCS brine is already salt saturated and unable to dissolve significant volumes of salt.
4) Seal integrity relies on stresses and may not be affected by seal embrittlement

8.2.3.9. Third Party induced migration

This risk includes the drilling of new wells and pressurizing of the BCS as separate causes that could lead in loss of containment. The risk of third-party drilling into our lease area has now been minimized as the Carbon Sequestration Lease was granted to Quest on 27 May 2011 and prohibits the drilling by third-parties below the Prairie Evaporite within the AOI. A request was issued separately to stop the creation of new Lotsberg salt caverns within the AOI.

The risk of pressurization of the BCS resulting in increased legacy well risk is also much reduced through the size of the approved Carbon Sequestration Lease AOI providing a minimum 25km offset from the development area to the AOI boundary.

8.3. Capacity

The uncertainty in the capacity of the primary container, the BCS, has been reduced considerably over time due to appraisal data gathering (3 appraisal wells, 2D seismic, 3D seismic and the ongoing reservoir modeling and feasibility studies). There is continued strong evidence for the BCS having the capacity to store the required volume for 25 years of injection. The residual uncertainty in pore volume is unlikely to decrease much further until several years of injection performance can be used to calibrate the existing reservoir models.

Definition of Quest Storage Capacity

In the setting of the Quest AOI, not having a structural trap, the accommodation mechanism is believed to be only relevant for plume conformance and CO_2 distribution with time and not a factor contributing to storage capacity during the injection timeframe.

Therefore, storage capacity in the Quest project is defined in line with Appendix 3 of the August 2008 issue of the Carbon Sequestration Atlas for the US and Canada [[Ref 8.5] Scott Frailey, Methodology for Development of Geologic Storage Estimates for CO_2]. This methodology is based on a material balance approach and acknowledges that the ultimate constraint to capacity is not the amount of available porespace (as the resident brine remains in that porespace) but the compressibility and maximum pressure (fracture gradients) limitation of the storage system. The formula for storage capacity under ideal conditions (unconstrained by well numbers) is provided below:

$$G_{CO2} = A\ h\ \phi\ \rho\ (c_r + c_w)\ (p_f - p_0)$$

Where A would represent the area of connected volume (in this case assumed to be the AOI), h the BCS thickness, ϕ the porosity, ρ°the CO_2 density, c_r and c_w the rock and water compressibility respectively and p_f and p_0 the fracture pressure constraint respectively the initial reservoir pressure. The CO_2 saturation and dissolution do not play a role in that formula but are obviously significant parameters that control conformance issues like long term CO_2 distribution and plume mobility.

Storage Efficiency

The storage capacity defined in the preceding paragraph represents a maximum estimate as it assumes that the entire pore space can be pressurized to the fracture pressure constraint. In reality the pressure contours around the injectors will follow a gradient with the maximum at the well constrained by this fracture pressure and with pressures away from the well gradually declining with distance. The more wells are utilized, the larger the area inside the pore space that can be pressurized to the fracture constraint and the higher the storage efficiency of the system. However, this increased storage efficiency comes at the cost of reduced economic efficiency as more wells may be required to inject the same volume of CO_2. Forecasted incremental injection forecasts per extra well, the price of each additional tonne of CO_2 captured and other commercial conditions will determine the economic maximum of the storage efficiency for the system.

In case of a large connected aquifer some pressure is likely to bleed off outside of the assigned pore space area, however, no credit can be accounted for this phenomena as an equal and opposite pressure margin should be reserved for potential future adjacent CCS schemes to compensate them for the loss of capacity in their pore space due to the fact that pressure pulses cannot be stopped at pore space boundaries. By allocating storage capacity to pore space owners based only on their areal ownerships rights, over-allocation of pore space capacity on a regional scale can be avoided. However, the relative timing of various neighbouring CCS schemes will be a very relevant factor in storage efficiency as the first CCS operators are more likely to reach high efficiency factors as they can use the full margin with respect to the fracture pressure. Subsequent CCS schemes will encounter reduced margins towards the fracture pressure (assuming these do not vary significantly across the storage horizon) and will require more wells to reach the same storage efficiency levels

8.3.1. Capacity assessment

The Gen-4 full field static reservoir models describe the range of subsurface uncertainty in terms of reservoir quality and reservoir connectivity, both key uncertainties that influence the maximum achievable injection rates into the reservoir (i.e. k*h), the plateau length of that injection rate and the total amount of CO2 that can be injected.

The ability to maintain injection rate over time and successfully inject the required total volume depends largely upon the initial pore volume in the reservoir and the pressure build up over time around injector wells. The ultimate storage capacity of the BCS reservoir for the Quest project is dependent upon the development strategy (storage efficiency), dynamic constraints (compressibility and fracture gradients) and the original brine filled pore volume in place that is determined by static parameters of the Gen-4 reservoir model.

The range of uncertainty in BCS pore volume equates to Water Initially In Place (WIIP) given 100% water saturation. The range is presented in *Table 8-3 BCS Pore Volume Range Within Quest AOI* and is asymmetric around the mid (P50) case and can be related to three main variables:

- The presence of a depositional trend impacting reservoir quality:
    - The P50 and P90 cases assume the presence of a depositional trend in reservoir quality within the BCS.
    - The asymmetry in the range reflects a greater downside pore volume should this reservoir quality trend be absent in reality.
    - The lack of a depositional trend leaves only a weak trend of improving reservoir quality to the NE (up-dip) associated with overburden compaction, as seen in the P10 equivalent pore thickness map in *Figure 8-12 BCS Porosity Thickness (m) Maps for the Cases Listed in Table 8-3. The Quest Boundary Polygon Used to Constrain the Pore Volumes is also Shown.*
- The thickness of the BCS unit:
    - The pore volume range in the table below also reflects uncertainty in the degree of BCS thinning onto a region of elevated Precambrian basement in the North of the AOI.
- Any remaining difference represents the risk of systematic error in the measurement of porosity from well logs.

Table 8-3 BCS Pore Volume Range Within Quest AOI

Case	Reservoir Connectivity	Reservoir Quality	Sum Pore Volume in Quest AOI (m^3)
P90	High	High	1.62E+10
P50	Mid	Mid	1.43E+10
P10	Low	Low	1.08E+10

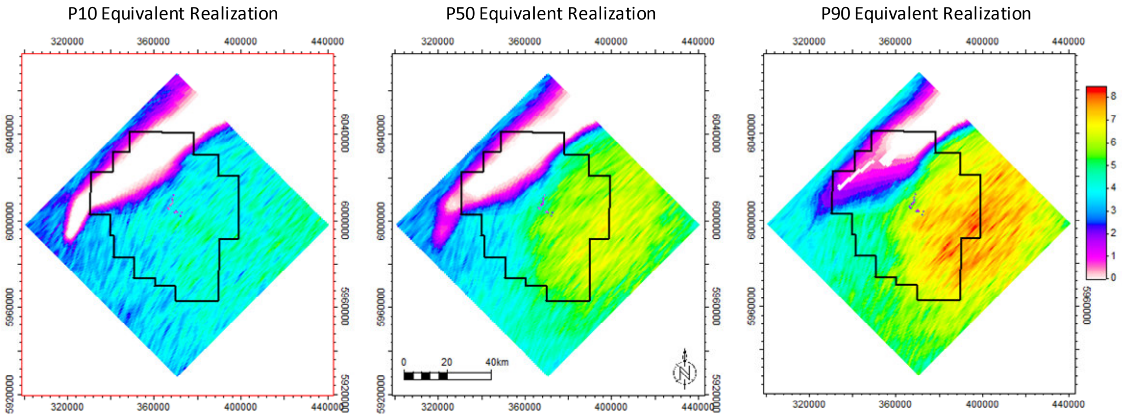


Figure 8-12 BCS Porosity Thickness (m) Maps for the Cases Listed in Table 8-3. The Quest Boundary Polygon Used to Constrain the Pore Volumes is also Shown

Using a simple material balance calculation:

$$G_{CO2} = A\ h_g\ \ f_{tot}\ r\ (c_p + c_w)\ (p\text{-}p_0)$$

Using the mid case properties:

Pres = 20 Mpa, Pmax = of 28 MPa, Temp = 60 C, Cp = 1.45 E-7, Cw = 2.78 E-7, r = 814 kg/m3.

A base case pore volume of 14.3 billion m3 within the AOI boundary could store 27 mln tonne of CO_2 at just under 70% storage efficiency, assuming a total compressibility of 0.406 E-6 1/kPa (2.8 E-6 1/psi) and a bottom hole pressure constraint 8 MPa above initial reservoir pressure.

8.3.2. Site specific risks to capacity

The site specific risks to storage capacity are identified and full risk descriptions and mitigation plans are maintained in the EasyRisk database. A bow-tie was not developed for this risk group as the storage capacity risks identified have no foreseen safety related consequences.

The following four risk and opportunities will be addressed in the below sections.

- Lower than expected Capacity as reservoir properties are worse than expected (R-4166)
- Poor lateral connectivity within the BCS (R-4130)
- Opportunity: Contribution of LMS to primary storage capacity in BCS could be higher than anticipated (R-4160)
- Future CCS schemes adjacent to Quest AOI could reduce the porespace capacity available to Quest (4832)

8.3.2.1. Lower than expected Capacity as reservoir properties are worse than expected

Radway 8-19 well data has confirmed but not narrowed the range of uncertainty in reservoir properties. A new facies characterised by high energy dunes, was cored for the first time in the Radway 8-19 well, at the base of the tide dominated bay margin (TDBM), representing the best reservoir quality cored to date. This facies is expected to occur more frequently throughout the AOI at the base of the BCS formation from where core was not previously recovered.

The Radway 8-19 well data indicated above average BCS thickness (46m), above average porosity (0.16) but below average net to gross (0.75)in the entire BCS at this location. Although the net to gross for the entire BCS was below average in the 8-19 Well, the net to gross in the TDBM was within the uncertainty range defined pre-drill based on offset well data. No cut-offs were used for the calculation of net reservoir. Fracture pressure data in Radway 8-19 was confirmed by a dedicated minifrac in the BCS and does not suggest a change of the bottom hole pressure constraint (28MPa) is required. The rock compressibility is still being measured through a special core analysis program but is expected to be confirmed at the expectation level of 1.0 E-6 1/psi.

8.3.2.2. Poor lateral connectivity within the BCS

One of the remaining storage capacity risks is associated with the unknown degree of connectivity of the BCS storage complex across the AOI and beyond, i.e. the possible presence of flow barriers and compartmentalisation.

The Radway 8-19 water injection test was not able to establish the presence of faults or flow barriers in the vicinity of the well, leaving compartmentalisation as a potential remaining risk to storage capacity. The BCS pore volume in the AOI is more than adequate to accommodate CO_2 volumes for 25 years of injection, but the connected volume to each injector will remain an uncertainty until pressure pulse testing between BCS wells can confirm the absence of pressure barriers due to faulting or geologic heterogeneities.

The 3D seismic data now covers approximately 415 km2 or about 11% of the AOI and the latest processed data, available since April 2011, indicates increased frequency content of the data (up to 100Hz) which for the first time allows for an interpretation of an event near the top BCS. The absence of interpreted faults continuing from top Precambrian interval to top of BCS on the 3D seismic dataset has reduced the probability of the presence of large scale flow boundaries across the BCS reservoir that could cause compartmentalisation.

Although the presence of strong multiples, the thickness of the BCS and the amplitude of the basement reflector present challenges for a reliable pick of top BCS, a BCS thickness map based on an isochron between the top basement and top BCS events can now be constructed from the 3D surface seismic. This map indicates BCS thickness and suggests the BCS to be thinning towards the north of the survey area as the Precambrian rises towards the “bald highs” interpreted from 2D seismic lines north of the Quest development area. This has been incorporated into the WIIP uncertainty ranges.

8.3.2.3. Opportunity: Contribution of LMS to primary storage capacity in BCS could be higher than anticipated

During the course of Gen-3 modelling [Ref 8.6] it became apparent that the methodology used to model vertical permeability through a Begg and King approach resulted not only in minimal CO_2 invasion into the overlying LMS but also minimal pressurization of this formation. This is a significant change from Gen-2 modelling where a different modeling approach and a less mature understanding of the depositional setting (i.e. distal bay environment in the LMS) resulted in significant pressure communication between the BCS and the entire LMS formation in the models.

As the base case modeling assumptions have now become more conservative with respect to pressure communication between these formations it is believed that the contribution of the LMS to primary storage capacity has changed from a risk to an opportunity. The LMS, if proven to be in pressure communication with the BCS, is now represents upside capacity for incremental CO_2 storage volumes in the BCS for the longer term.

8.3.2.4. Future CCS schemes adjacent to Quest AOI could reduce the pore space capacity available to Quest

A new risk was introduced to capture possible negative impact of future CCS schemes adjacent to the Quest storage site on storage capacity. The containment risks associated with this risk were already captured in the existing “Third Party induced migration” risk whilst the injectivity risk of other CCS schemes contributing to rising BCS pressures are captured under “Loss of Injectivity due to pressure build-up”.

8.4. Injectivity

The key factor driving the reduction of uncertainty in injectivity is the placement and testing of the first Quest development well (Radway 8-19) in the centre of the area of interest. Radway 8-19 has provided updated information on the key parameters that impact injection capacity (permeability, reservoir pore pressure and formation fracture pressure). The offset of Radway 8-19 to the next two nearest development injectors wells 7-1 and 5-35 is expected to be 6.8 and 5.5km respectively. This is much less than the outsteps made from Redwater 3-4 to Radway 8-19 (24.5 km) and from Redwater 11-32 to Redwater 3-4 (15.8 km), although still much larger than the scale of reservoir quality variability expected in the BCS.

Definition of Injectivity

The relationship between rate and flow in a porous medium is well understood and extensively documented in the public literature based on the Darcy flow equations. The formula provided below defines the pressure differential for a gas in the well bore as a function of rate and a number of other reservoir and fluid parameters.

$$P_{avg}^2 - P_{wf}^2 = 1422\ T\ Q\ \ \mu Z\ /\ kh\ (\ln r_e/r_w - 3/4 + S + DQ)$$

Where P_{avg} and P_{wf} represent the average reservoir pressure and flowing well bore pressure respectively, T represents the reservoir temperature, Q the flow rate, μ the viscosity of the injected CO2, Z the gas factor for the injected CO2 at injection conditions, k the total permeability of the BCS to CO2, h the BCS thickness, r_e/r_w the ratio of radius of investigation to well bore radius, S the skin (well bore formation damage) and DQ the rate dependant skin factor (non-Darcy skin).

This formula controls injectivity as the pressure differential in a well should not exceed the margin between the bottom hole pressure constraint based on fracture gradients and the initial reservoir pressure. From this formula it is apparent that the biggest variable controlling injectivity is kh, the product of permeability and height. The only controllable parameters are the applied pressure differential that Quest proposes to base on fracture pressure constraints and the minimization of formation damage (skin) through good drilling and completion practices.

8.4.1. Initial Injectivity assessment

Two water injection tests were conducted during the Quest exploration and appraisal phase that provide important information to benchmark injectivity estimates.

Injectivity was estimated using average pressures and flow rates for the last stable flow period of the Redwater 11-32 water injection test and the 5th and final Radway 8-19 water injection test. A summary of the results is provided in the table below:

Table 8-4 Injectivity Estimates for Redwater 11-31 and Radway 8-19 Water Injection Tests

Well Name	Rate [m3/d]	DeltaP [kPa]	Injectivity [m3/d/MPa]
Redwater 11-32	492	12.13	41
Radway 8-19	360	0.95	379

The data indicates a large range in injectivity, with the injectivity in Radway 8-19, located in the middle of the Quest AOI, being some ten times larger than that measured in Redwater 11-32, despite some operational issues around pressure build-up during the Radway 8-19 injection test [Ref 8.7] these have subsequently been attributed to water quality issues.

Injectivity can be used to extrapolate estimated water injection rates to the pressure differential associated with normal operating conditions. In this case, operating conditions were assumed to correspond to a flowing bottom hole pressure of around 26 MPa, some 6 MPa above initial reservoir pressure at top of the BCS in Radway 8-19. Water injection rates can then be converted to CO_2 injection rates by making assumptions on the fluid property differences between the injected water and the CO_2 (i.e. viscosity) and the CO_2/brine displacement model (relative permeabilities). Taking these factors into account CO_2 is expected to inject at rates that are a ratio of 1.5 to 3 higher than water injection rates (expressed in reservoir volume*). Figure 8-13 Actual Well Test Injectivity Versus Full Quest Project Injection Requirements* illustrates the several steps required to compare well test rates to Project injection requirements.

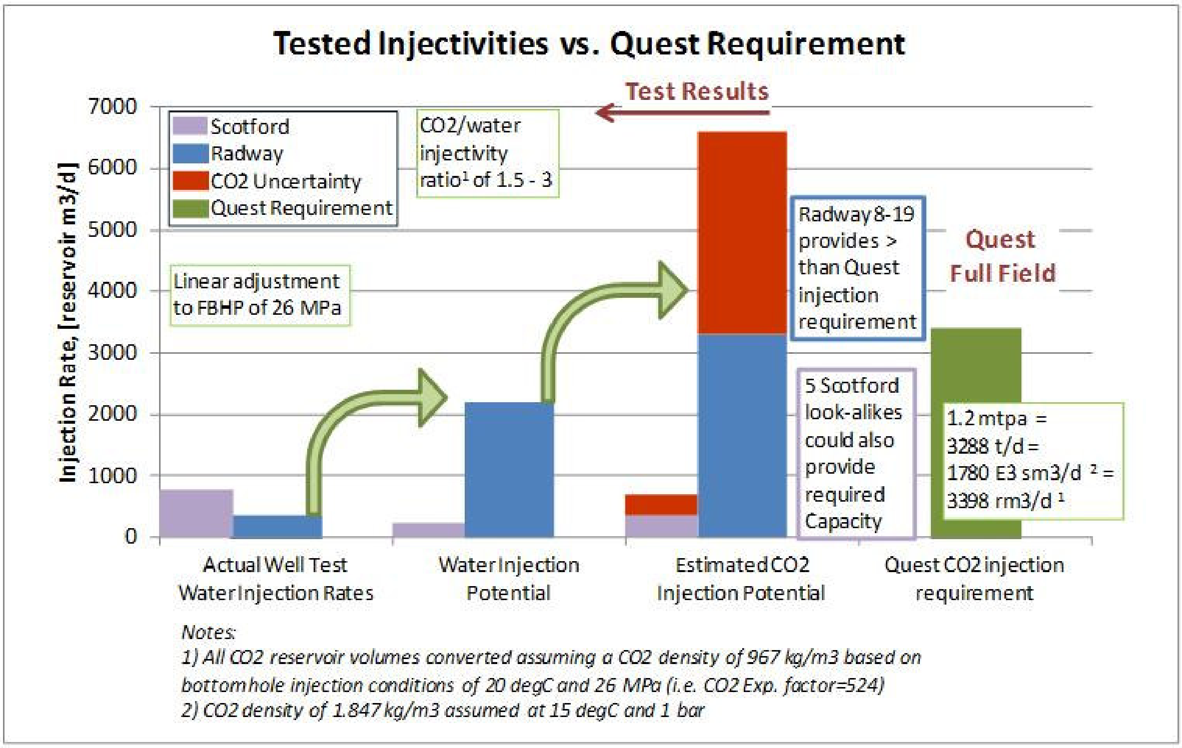


Figure 8-13 Actual Well Test Injectivity Versus Full Quest Project Injection Requirements

This figure illustrates that Radway 8-19 is expected to provide sufficient injectivity to initially take the full Quest project volume into a single well. However, critical elements that need to be considered are:

- Ignores well bore and 6" lateral pipeline constraints that may limit flow capacity.
- Ignores plume conformance issues that may result in undesirable plume sizes if all injection was to go into a single injector.
- The Radway 8-19 water injection test was problematic due to water quality issues.
- For redundancy purposes Quest has adopted an Operations Philosophy that requires full project injection capacity (1.2 Mtpa) to be met by all available injection wells, even in a case of a single well failure. This means that, in case Radway 8-19 was to suffer some downtime, the remaining injectors should still be able to meet Project injection requirements.

The remaining injection wells that are still to be drilled must therefore provide a total combined injectivity of around 400 m3/d/MPa of water to be able to continue to store and inject full project volumes in the BCS even in the case of a Radway 8-19 failure.

8.4.2. Pressure Modeling Results

A primary objective of Gen-4 modeling effort [Ref 8.2] is to assess the potential for achieving sustained injectivity in the presence of the current subsurface uncertainty. The number of injector wells required at Quest is a critical component of the development plan and associated economics. **The range of wells required to mitigate the range of subsurface uncertainty is 3 – 8.**

Gen-3 modeling suggested a range of between 3 and 10 wells was necessary to cover the range of subsurface realizations. Gen-4 modeling involved integration of the recently drilled and tested Radway 8-19 well and the acquisition of the full area of 3D seismic over the development AOI. Gen-4 results show that the range of wells required is slightly less than Gen-3 with 3 wells covering the expectation case, and 5 wells being probable. Low probability cases, primarily with reservoir properties poorer than the Radway well, extends the well count to 8 or more wells.

Further evaluation of the GEN 4 expectation case concludes the following:

- Less than 3MPa delta pressure is required to successfully inject 27 Mt of CO2 into the BCS over a period of 25 years.
- More than double the current volume targets of CO2 could be injected into these wells.
- The approved AOI is sufficient area that potential offset sequestration schemes are not a concern for the current volume targets.

8.4.2.1. Number of Injection Wells Required

Injectivity modeling over the full range of reservoir realizations has demonstrated that all considered reservoir scenario's can provide sufficient **initial** injectivity with three to five injection wells. A few key cases that support the opening statement will be elaborated in this section.

As the majority of the aquifer area (10 000 km^2) influencing the injectivity of the wells are intrinsically modelled there is little impact observed by adding limited or infinite analytical aquifers to the edges of the model as discussed in the previous chapter. For robustness the analytical aquifer extensions were therefore turned off for all runs discussed here. Once the project is operating with final well count it is recommended that the aquifer extents be revisited in detail as they will have a significant impact on closure conformance.

Expectation Case:

In the Mid reservoir property and Mid reservoir connectivity scenario, three wells are more than adequate to sustain an injection plateau of 1.08 Mtpa for 25 years without ever reaching bottom hole pressure constraints. This is illustrated in *Figure 8-14 Expectation*

Case Reservoir Property and Reservoir Connectivity Scenario Map and *Figure 8-15 25 Year FBHP Forecast for a Three Injection Well Development in the Base Property and Base Connectivity Scenario*

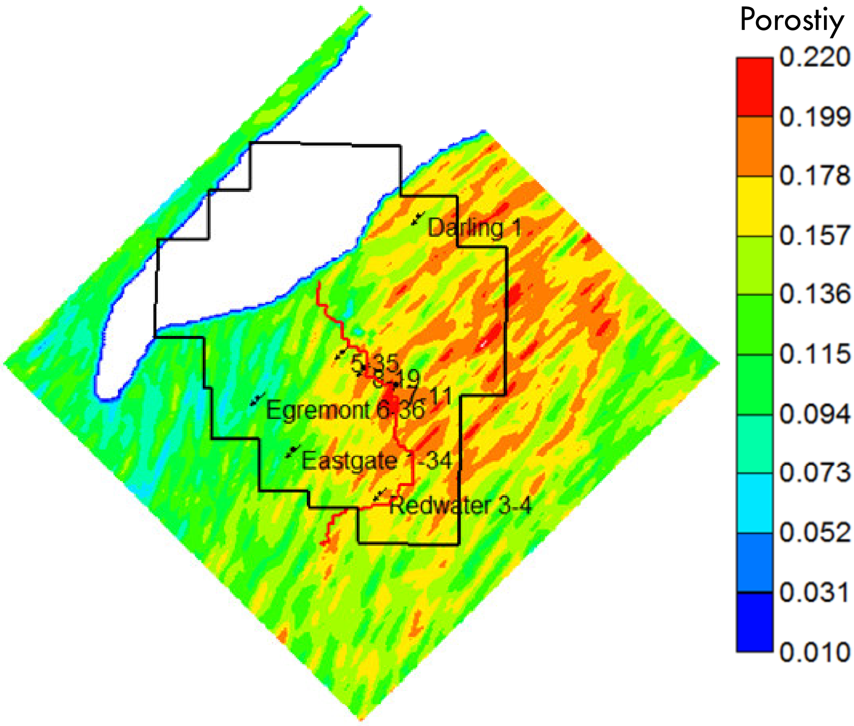


Figure 8-14 Expectation Case Reservoir Property and Reservoir Connectivity Scenario Map

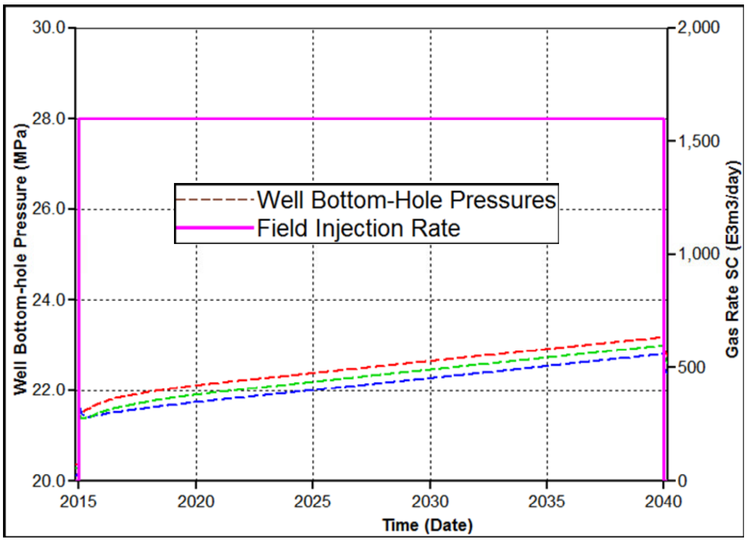


Figure 8-15 25 Year FBHP Forecast for a Three Injection Well Development in the Base Property and Base Connectivity Scenario

The expectation case realization can successfully inject the required volume of CO2 in a 25yr period with only the Radway well. However this is an unrealistic outcome as more than one well will be drilled to overcome uncertainty and reliability risk. At least a second well is required to provide backup injection in case the first well is shut-in for operations reasons. However, the decision has been made that the project will have a minimum of three injection wells for the following reasons:

- The Quest project is continuing to appraise while developing and the current model is extrapolating data over distances of ~20km. Therefore, confirmation of reservoir quality on a larger scale is required prior to commissioning the project to ensure we have sufficient well count.
- Without certainty that the second well will be as good as the Radway well and if the next wells had reservoir properties closer to either the Scotford and Redwater wells then it would be unable to handle the full injection rate, therefore, a third well is needed.
- A commitment has been made in the Regulatory Submission that there is a minimum of 3 injection wells.

Low-Low Case:

Due to the appraise while developing nature of the project the three and five well scenario's have been tested against the low reservoir property and low reservoir connectivity realization (as illustrated in *Figure 8-16 Low Property and Low Connectivity*

Scenario Map) to ensure sufficient injectivity and capacity at start-up. The following observations have been made:

- In a three well case very high injection pressures will be observed with pressure building to the 28MPa BHP limitation almost immediately and approximately five years to drill an additional 2 wells and extend the pipeline, and a further 8 years to take the well count to 8 as illustrated in 25 Year FBHP Forecast for the Initial Three Injection Wells of a 3 Phase Eight Well Development in the Low Property and Low Connectivity Scenario
- In comparison five injection wells are more than adequate for start-up and will be able to sustain an injection plateau of 1.08 Mtpa for 13 years before reaching a bottom hole pressure constraint of 28 MPa. This is illustrated in *Figure 8-18 25 Year FBHP Forecast for the Initial Five Injection Wells of a 2 Phase Eight Well Development in* the Low Property and Low Connectivity Scenario.

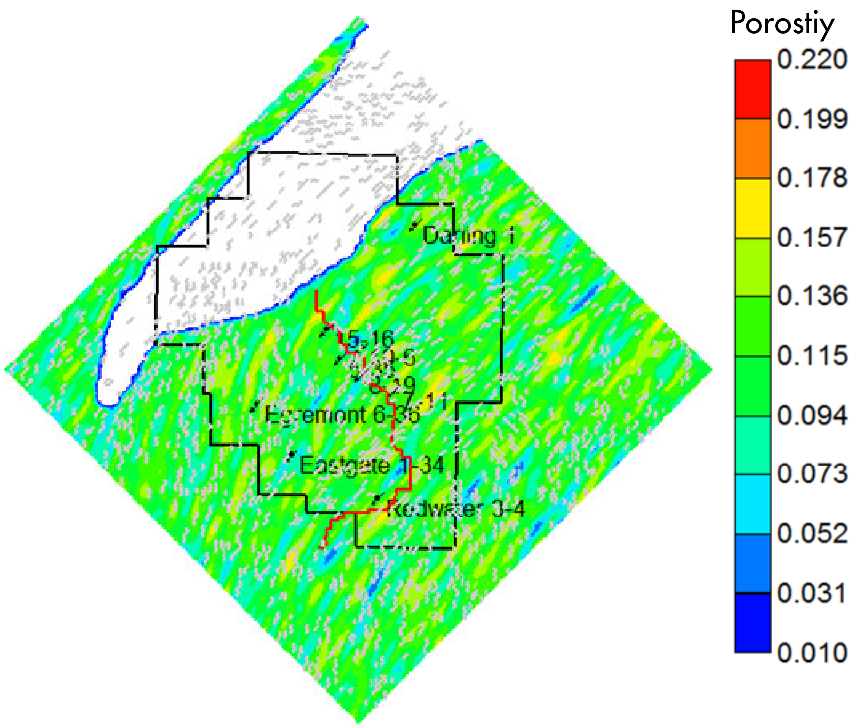


Figure 8-16 Low Property and Low Connectivity Scenario Map

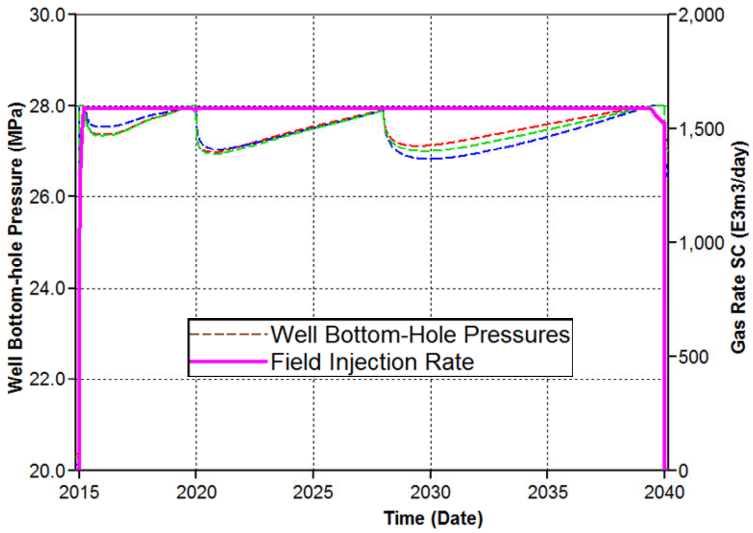


Figure 8-17 25 Year FBHP Forecast for the Initial Three Injection Wells of a 3 Phase Eight Well Development in the Low Property and Low Connectivity Scenario

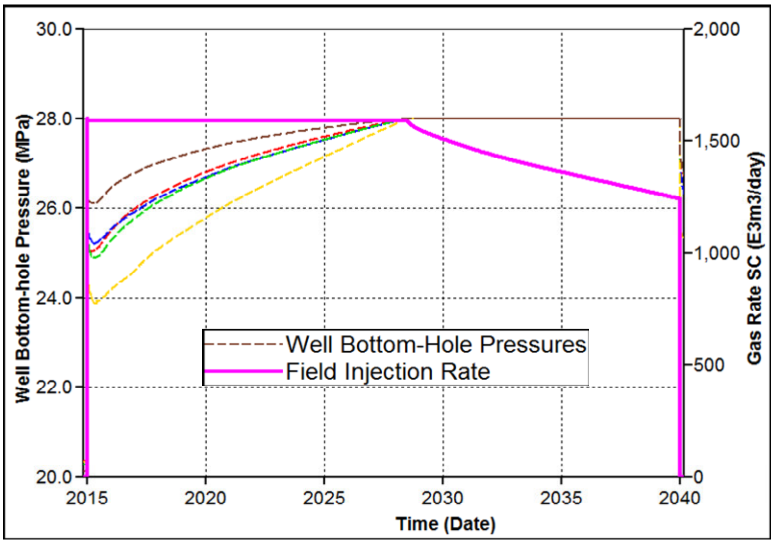


Figure 8-18 25 Year FBHP Forecast for the Initial Five Injection Wells of a 2 Phase Eight Well Development in the Low Property and Low Connectivity Scenario

8.4.2.2. Injectivity declining with time

The low reservoir property and low reservoir connectivity scenario illustrated in *Figure 8-18 25 Year FBHP Forecast for the Initial Five Injection Wells of a 2 Phase Eight Well Development in* the Low Property and Low Connectivity Scenario is an example of a reservoir realization that could result in declining injectivity with time. Other scenarios that could have a similar effect are:

- A gradual build-up of well bore damage or increasing skin, but this is expected to be at least partially reversible through well intervention (i.e. well bore clean-up or acid stimulation).
- Increasing CO2 viscosity with decreasing temperatures and increasing non-Darcy skin with increasing well rates were also investigated with marginal impacts.

All of the above impacts can be mitigated by increasing injection pressure. Only in the low reservoir property and low reservoir connectivity scenario low-low realization, after 13 years of injection, when we reach our maximum FBHP do we need to consider other measures. The declining injectivity in the low-low scenario is the result of a combination of limited aquifer connectivity and a low BCS reservoir storage capacity. There are two potential mitigations to pressure build-up in the BCS:

1) by spreading out the injection wells over a larger area (i.e. infill drilling on the perimeter of the development)
2) the most effective way to address a shortage of storage capacity is to increase that capacity by lifting the bottom hole pressure constraints from the current 28MPa BHP constraint to the 32 MPa BHP requested from the ERCB in the D65 Regulatory submission.

These two mitigations to declining injectivity, infill drilling and increasing BHP constraints are illustrated in *Figure 8-19 25 Year FBHP Forecast for a Five Injection Well Development Ramping up to Eight Injection Wells in 2028 in the Low Property and Low Connectivity Scenario* and *Figure 8-20 25 Year FBHP Forecast for a Five Injection Well Development at a 28 MPa BHP Constraint Ramping up to 29 MPa Between 2028 and 2039 in the Low Property and Low Connectivity Scenario* respectively. Note that the eight wells used in figure 7-19 were the wells applied for and that strategic placement of perimeter wells could reduce required well count.

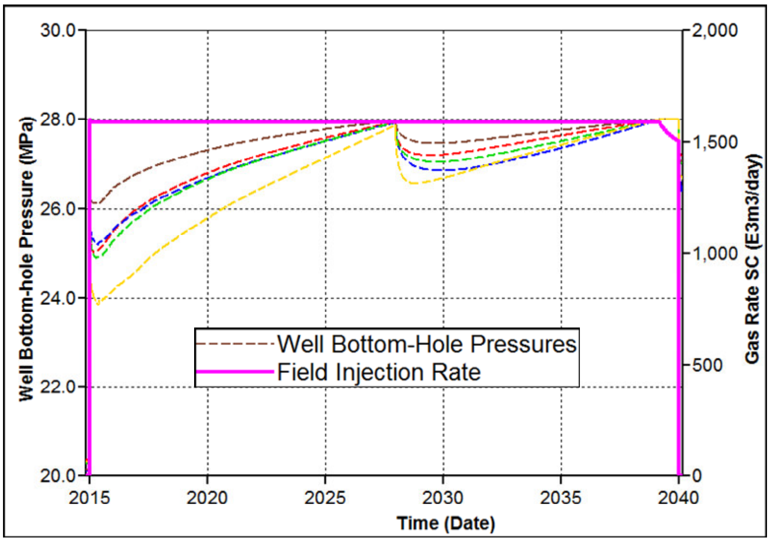


Figure 8-19 25 Year FBHP Forecast for a Five Injection Well Development Ramping up to Eight Injection Wells in 2028 in the Low Property and Low Connectivity Scenario

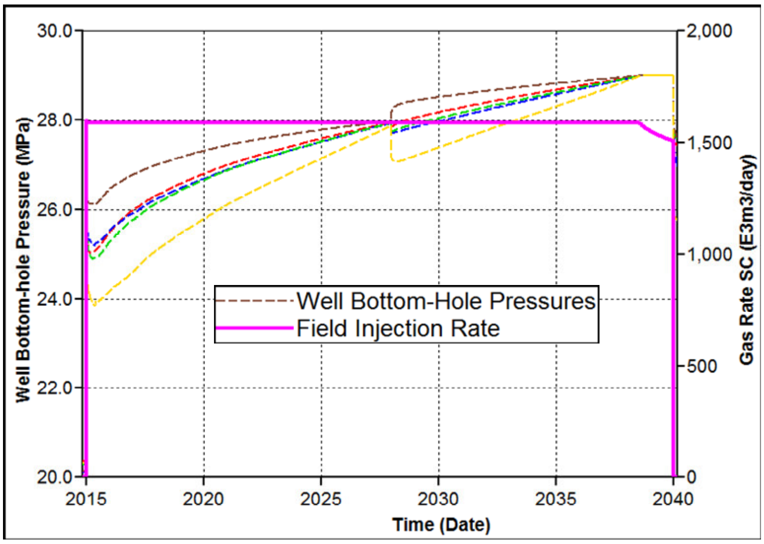


Figure 8-20 25 Year FBHP Forecast for a Five Injection Well Development at a 28 MPa BHP Constraint Ramping up to 29 MPa Between 2028 and 2039 in the Low Property and Low Connectivity Scenario

8.4.2.3. Growth Scenario

There is a lot of potential for further CO2 sequestration within the current Sequestration Lease AOI. The industrial heartland around Fort Saskatchewan has the potential for considerable volumes of additional CO2. This can be realized by either continuation of injection of 1.08 Mtpa past 2040 or by increasing the injection rates. The compressor and pipeline have been designed to have spare capacity in the event of the expectation case realization.

A mid reservoir quality, low reservoir connectivity, mid dynamic property realization with 3 injection wells was run at 1.08 Mtpa for 75 years as illustrated in *Figure 8-21 75 Year FBHP Forecast for a Three Injection Well Development Injecting 1.08 Mtpa in the Mid Property and Mid Connectivity Scenario*. A mid reservoir quality, mid reservoir connectivity, mid dynamic property realization with 3 injection wells was run at 5.2 Mtpa for 25 years as illustrated in *Figure 8-22 25 Year FBHP Forecast for a Three Injection Well Development Injecting 5.2 Mtpa in the Mid Property and Low Connectivity Scenario*

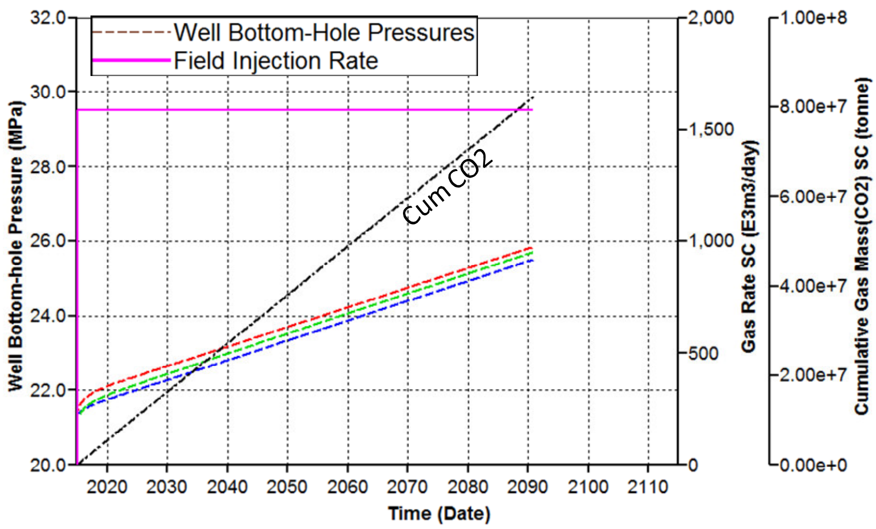


Figure 8-21 75 Year FBHP Forecast for a Three Injection Well Development Injecting 1.08 Mtpa in the Mid Property and Mid Connectivity Scenario

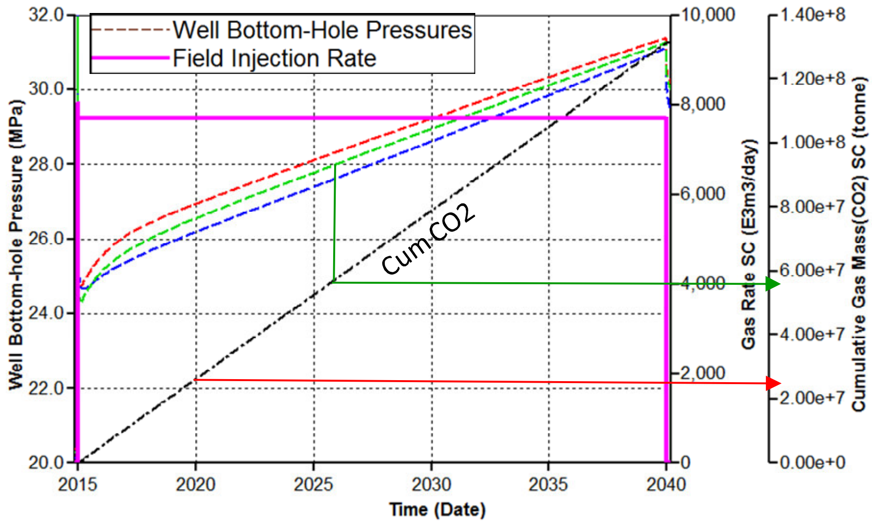


Figure 8-22 25 Year FBHP Forecast for a Three Injection Well Development Injecting 5.2 Mtpa in the Mid Property and Low Connectivity Scenario

These two figures imply:

- That the 1.08 Mtpa rate can be maintained for about 100 years before approaching the maximum BHP; it would seem prudent to increase the rate to utilize this asset.
- Or that the targeted 27 Mt's could be injected at 5.2 Mtpa in about 5 years (red arrow); this leaves an additional 20 years to sequester 5 times as much CO2. It should be noted that we hit the 28 MPa bottom hole pressure constraint after 10 years injection which corresponds to injection of double the target volume (green arrow). However, at that point it would be entirely feasible to add new injectors within the existing pore space to extend the plateau for the required duration of injection; in this illustration the bottom hole pressure constraint is overridden and injection continues to 2040.

Various permutations can be conceived with combinations of rate, time, BHP, well count, and well location for the various geological realizations. However, it is most likely that the Quest project has room for considerable future additional CO2 volumes.

8.4.2.4. Offset CO2 Sequestration Schemes

In the event that a mid to high reservoir property realization is confirmed it is possible that offset CO2 sequestration schemes may be developed in the future. This can be evaluated using two methodologies:

1)Assuming an offset scheme on all sides of the AOI would be the equivalent of a no flow boundary being applied on all sides of the AOI. In this case 27Mt of CO2 can be stored while not exceeding a 5MPa increase in BHP and continued injection could store ~50Mt of CO2 prior to exceeding the 28MPa BHP constraint in the mid case. *Figure 8-23 Urban Planning Scenario assuming an offset CCS scheme on all AOI boundaries.*

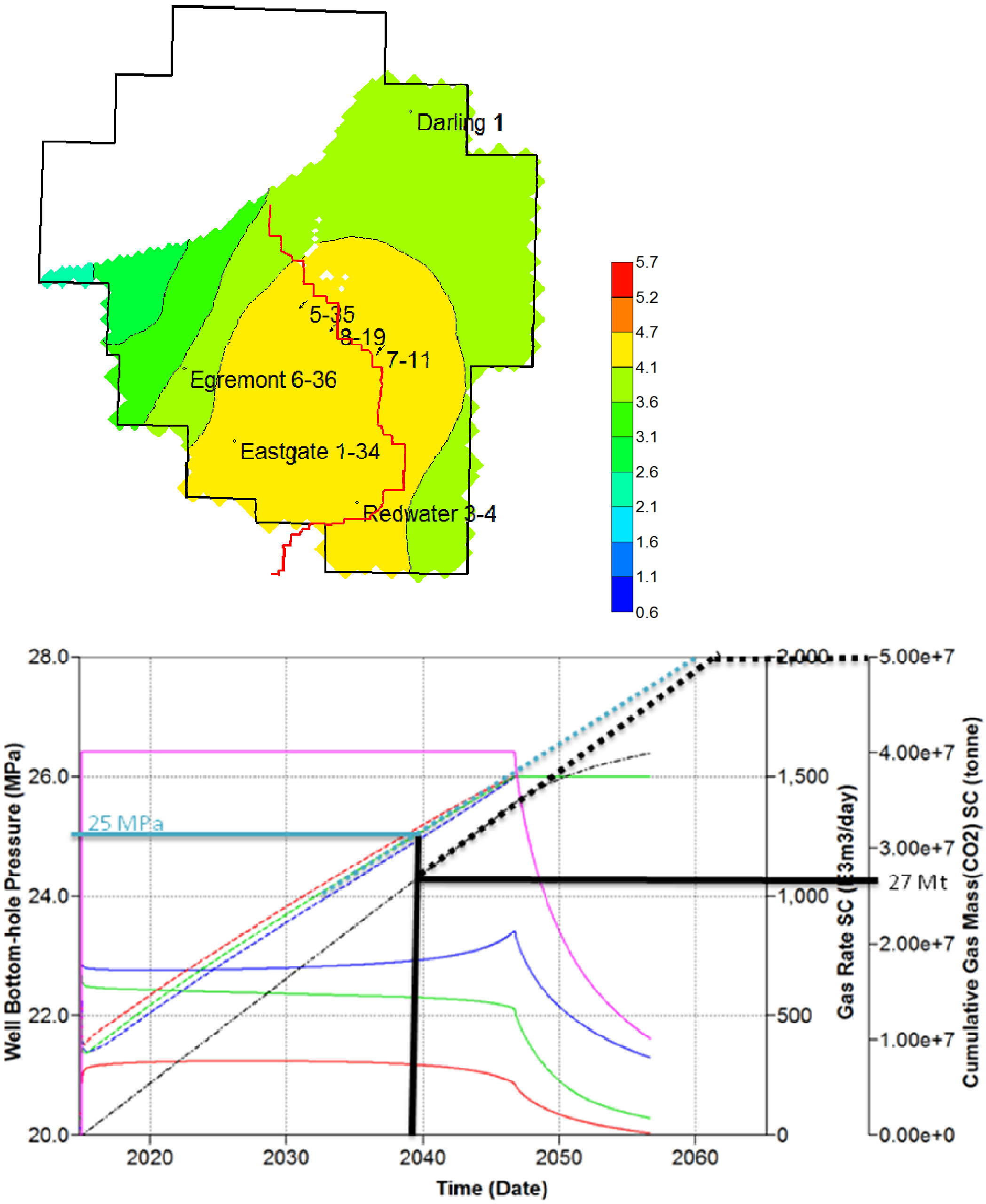


Figure 8-23 Urban Planning Scenario assuming an offset CCS scheme on all AOI boundaries.

2) A second method of evaluating this question is to assume that offset schemes would effectively shrink the pore volume available to quest for pressure relief. The expectation case scenario was run iteratively while shrinking the models boundaries to determine how large of an area we will likely need. *Figure 8-24 Minimum Area Required to Inject 1.08 Mtpa of CO2 into Three Wells Over 25 Years in the Mid Property and Mid Connectivity Scenario Without Exceeding 28 MPa FBHP* illustrates that an area of approximately 1500 km^2 is required to contain our 27 Mt of CO_2 while not exceeding the designed maximum bottom hole pressure of 28 MPa. With lower reservoir properties a larger area or more wells and or higher injection pressure would be required.

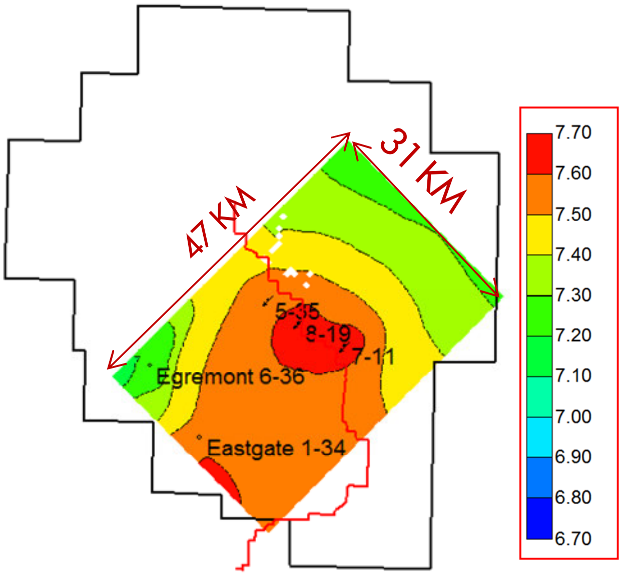


Figure 8-24 Minimum Area Required to Inject 1.08 Mtpa of CO2 into Three Wells Over 25 Years in the Mid Property and Mid Connectivity Scenario Without Exceeding 28 MPa FBHP

8.4.2.5. Legacy Well Pressures

The four legacy wells in the AOI will encounter pressurized saline brine. Given the BCS reservoir pressure (20,036 kPa) and insitu fluid gradient (11.7 kPa/m) a minimum incremental pressure of 3.3 – 4.2 MPa in the BCS would be required to lift BCS brine into the Base of Ground Water Protection zone (BGWP) through an open hole at hydrostatic conditions (

Table 8-5 Pressure Increase Required to Lift BCS Brine to the Base Groundwater Protection). Note that the Westcoast 9-31 legacy well does not penetrate the BCS and therefore was not included in the modeling. However, the Redwater 3-4 project well was included as an observation well.

Table 8-5 Pressure Increase Required to Lift BCS Brine to the Base Groundwater Protection

Well Name	Surface elevation (mBSL)	BGP depth (mBSL)	Hydrostatic pressure at BGP (kPaa)	Extrapolated BCS pressure at BGP (kPaa)	Delta P (kPa)
Imperial Eastgate No. 1-34	-641.3	-401	2,456	996	3,452
Imperial Egremont W 6-36	-627.9	-408	2,259	1,175	3,334
Imperial Darling No. 1	-704.4	-469	2,406	1,795	4,201
Westcoast 9-31	-699	-471	2,338	1,808	4,146
NOTE: mBSL – metres below sea level					

Current dynamic models indicate that the pressure increases expected at the legacy wells will be about half that required to lift BCS brine into the BGWP or to surface *Figure 8-25 25 Year Pressure Drop From Time Zero Forecast for the Legacy Wells Using the Mid Property and Mid Connectivity Scenario*. Note the pressure build is plotted as a negative pressure drop at legacy wells. Furthermore this figure illustrates that in the expectation case the FBHP does not ever exceed the delta pressure required to lift BCS brine to BGWP at the injection wells. *Figure 8-26 25 Year Pressure Drop From Time Zero Forecast for the Legacy Wells Using the Low Property and Low Connectivity Scenario* illustrates that in the event of a low property and low connectivity case we have 15 years to implement a mitigation strategy.

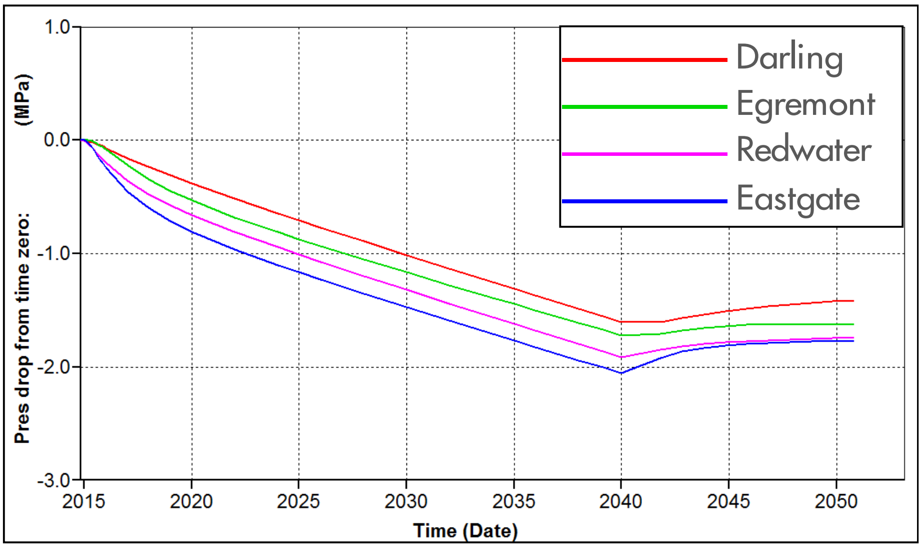


Figure 8-25 25 Year Pressure Drop From Time Zero Forecast for the Legacy Wells Using the Mid Property and Mid Connectivity Scenario

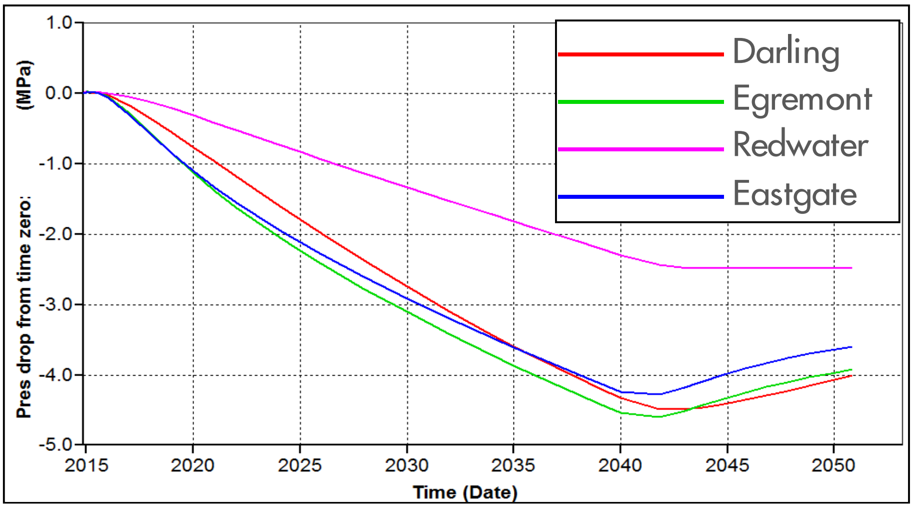


Figure 8-26 25 Year Pressure Drop From Time Zero Forecast for the Legacy Wells Using the Low Property and Low Connectivity Scenario

However, if one includes the analytical aquifer extension we can see that:

- The pressures at the legacy wells are predicted to be at or below that required to lift BCS brine into the BGP or to surface (see *Figure 8-27 25 Year Pressure Drop From Time Zero Forecast for the Legacy Wells Using the Low Property and Low Connectivity Scenario With Analytical Aquifer Extension.*).
- 10 years into the project it is very reasonable to assume that a combination of well and reservoir management, possibly with infill drilling, could keep the pressures at the legacy wells below the lift threshold. For example:
    - The slope change in 2028 indicates that one of the new wells is in close communication with Egremont and causing it to pressure up faster, injection pressures at this well could be
    - *Figure 8-28 25 Year Pressure Drop from Time Zero Forecast for the Legacy Wells using the Low Property and Mid Connectivity Scenario with Analytical Aquifer Extension* illustrates that with mid connectivity the Egremont well does not experience the pressure increase observed in the low connectivity case as the injection is more spread out.

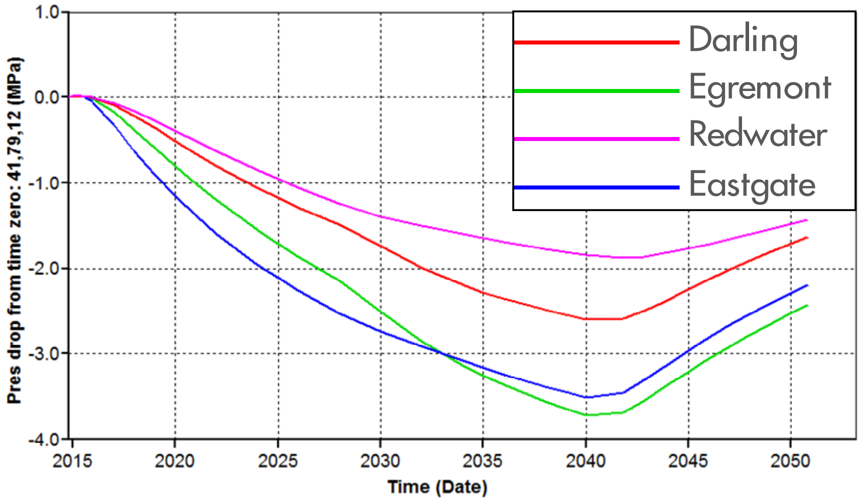


Figure 8-27 25 Year Pressure Drop From Time Zero Forecast for the Legacy Wells Using the Low Property and Low Connectivity Scenario With Analytical Aquifer Extension.

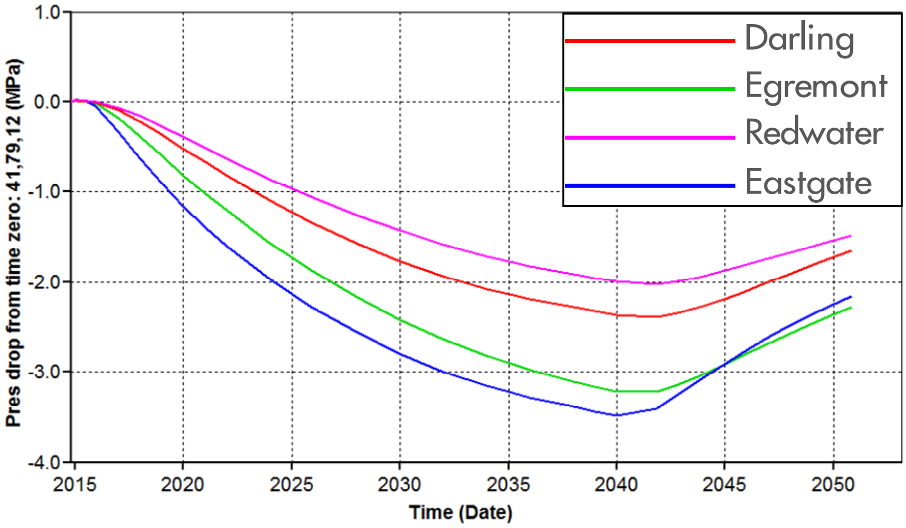


Figure 8-28 25 Year Pressure Drop from Time Zero Forecast for the Legacy Wells using the Low Property and Mid Connectivity Scenario with Analytical Aquifer Extension

Alternatively, accepting the leakage risk is a plausible solution as:

- The delta P at the wells is small and for a short duration.
- The delta P assumes an open conduit and all of these wells are abandoned with more than one cement plug.
- The results from a radial well leak model indicates that even in the event of a 10,000 mD open well the uphole contamination is expected to be minimal

Figure 8-29 Initial Permeability X-Section and 30 Year Forecast of the Invasion Profile as Depicted in the Salinity X-Section. This is because:

- As most of these layers have tight permeability they do not readily receive water injection.
- The Cooking Lake is under pressured and no scenario ran had brine move higher than the Cooking Lake as it is a pressure sink. For illustration purposes in GWPZ the second layer had its porosity and permeability adjusted artificially high; no invasion was observed.
- For more details see GEN 4 IRM report [Ref 8.2]

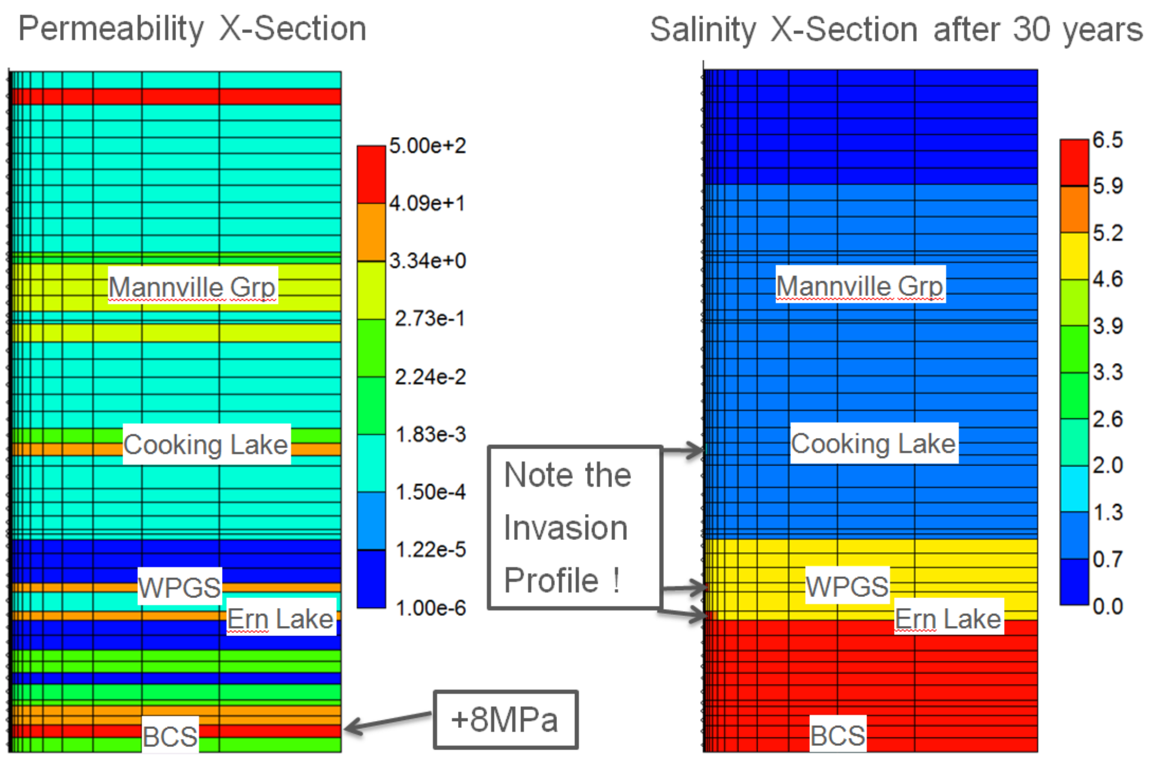


Figure 8-29 Initial Permeability X-Section and 30 Year Forecast of the Invasion Profile as Depicted in the Salinity X-Section

The Legacy well pressures will be a more probable concern in the event of the growth scenarios. The extended injection of 1.08 Mtpa will cut off in about 50 years resulting in a total injection of 54 Mts of CO2 storage. Alternatively, if the rate were to be ramped up as in figure 7-20 then the pressure rise quickly resulting in pressure exceeding what could displace BCS brine up legacy wells as soon as 7 years; resulting in only about 40 Mt's of CO2 storage.

8.4.3. Site specific risks to injectivity

The site specific risks to injectivity are identified and full risk descriptions and mitigation plans are maintained in the EasyRisk database. A bow-tie was not developed for this risk group as the injectivity risks identified have no foreseen safety related consequences.

The following eight risk and opportunities will be addressed in the below sections.

- High Injectivity due to higher than expected near well bore properties (kh and skin) (R-4842)
- Low Injectivity due to poorer than expected near well bore properties (kh and skin) (R-4135)
- CO2 injectivity overestimated from H2O test (rel.perm. & Non-Darcy skin) (R-4150)
- Loss of Injectivity due to pressure build-up (R-4172)
- Loss of Injectivity due to dropping BHP constraints (R-4136)
- Loss of Injectivity due to Operational upsets (R-4131)
- Loss of Injectivity due to well interventions (MMV/integrity) (R-4525)
- Loss of Injectivity due to geochemical alteration of the reservoir / Halite precipitation (R-4155)

8.4.3.1. High Injectivity due to higher than expected near well bore properties

This "risk" was created to capture the opportunity that less than 5 wells can potentially be drilled in the base case development whilst still meeting the required system capacity of 1.2 Mtpa. The probability of requiring less than 5 wells is currently assessed as High (50-80%) with a cost impact that is also High (25-50 mln CAD), representing the opportunity to save two injectors, associated MMV wells and 17 km of pipeline. Capturing this opportunity is the driver behind the phased development approach taken in the SDP.

This Opportunity needs to be captured by December 2012, as most of the potential cost savings will evaporate after this date when commitments for the length of the pipeline need to be made, and drives the timing of drilling development wells 2 and 3 in the summer 2012 drilling season.

8.4.3.2. Low Injectivity due to poorer than expected near well bore properties

The drilling and testing of Radway 8-19 has reduced the probability of this risk, as Radway 8-19 was tested to potentially provide more than the required system capacity of 1.2 Mtpa. The chance that more than 5 injection wells are required has now become considerably less likely. It is believed that full system injectivity at start-up can initially be achieved with no more than five wells. Injection wells 6 to 8 are carried to mitigate against the risks of pressure build-up, declining BHP constraints or skin build-up due to operational upset or well interventions, but are not expected to be required for initial injectivity.

The SDP to drill the 2nd and 3rd development wells immediately after FID in 2012 will further mitigate this risk. Water injection test are planned on both those wells to reduce uncertainty on initial injectivity based on near well bore properties (kh and skin).

Water injection tests are required to support the decision whether or not additional injection wells and a pipeline extension are required. This decision would be required by December 2012 to allow the pipeline to be completed before start-up in January 2015, whilst the extra wells would be drilled in the winter of 2013/2014 should more than 3 injection wells be required.

8.4.3.3. CO2 injectivity overestimated from H2O test (rel.perm & Non-Darcy skin)

A review of Generation-4 relative permeability curves, based on special core analysis and an analog data review, and radial well modeling has demonstrated the impact of this uncertainty to be small. The current range used in the Gen-4 relative permeability curves predicts a +25%/-20% range in the estimated injectivity per well, much less than the uncertainty associated with reservoir property distribution.

The small to medium uncertainty range associated with this risk combined with the logistical and regulatory challenges of planning for a CO2 pilot test in the storage site resulted in an early 2011 decision NOT to test CO2 prior to FID. Testing may still be beneficial to address start-up and operational issues but will bring little benefit to reduce remaining uncertainty on injectivity. Also, there now appears to be an opportunity to use the phased start-up of HMU's (HMU3 starting end 2014, followed by the remaining HMU's in 2015) to have a prolonged start-up period which may negate the need for CO2 testing prior to 1st injection in 2014.

8.4.3.4. Loss of Injectivity due to pressure build-up

Limited new data has become available on this risk, as the planned long water injection test in Radway 8-19 failed to provide any interpretable indication for the presence or absence of flow barriers in the reservoir, due to operational test issues. However, new 3D surface seismic provides evidence for the absence of large scale faults extending from top Precambrian to top BCS and have reduced the likelihood of compartmentalization.

Options are being considered to incorporate a pulse test in the injection test of a 2nd and 3rd development well. Both Radway 8-19 and Redwater 3-4 (if converted to a BCS observation well) are considered candidates to be used for monitoring the pressure response from injection into the new wells. A pulse test is also considered, as part of the start-up strategy, as the wells will be started up sequentially and downhole gauges can be monitored for interference in adjacent shut-in injection wells

8.4.3.5. Loss of Injectivity due to dropping BHP constraints

Fracture pressures and gradients were interpreted from the Radway 8-19 BCS minifrac data and are supported by log based analysis of minimum horizontal formation strengths in the various formations of the storage complex. The Radway 8-19 minifrac test in the BCS confirmed the data acquired earlier at Redwater 11-32. Also, the 9 5/8" casing shoe leak off test in the LMS confirmed LMS minifrac results from the Redwater 11-32 well. A D65 application with fracture data and a D51 approval to inject have been prepared and submitted to the ERCB based on the LMS fracture propagation pressure gradient of 20.6 kPa/m.

A residual uncertainty exists around the degree of reduction in fracture gradients due to cooling. This risk is currently being addressed by special core analysis through the measurement of the thermal expansion coefficient on Radway 8-19 core. This work will help determine whether the 4MPa margin that the project has already incorporated to buffer the effect that reservoir cooling may have on fracture gradients is adequate to help prevent loss of containment issues due the fracturing of the seals in the storage complex.

8.4.3.6. Loss of Injectivity due to Operational upsets

Radway 8-19 testing has demonstrated the vulnerability of injectivity to fluid contamination issues. Other acid gas operations within Shell also experienced injectivity issues and partner feedback from CO2 injection in EOR operations also indicated a high potential for injectivity issues following operational upsets. Although injectivity in the above cases appear to have been successfully restored through stimulation and workovers, higher than anticipated well down time (i.e. well intervention and stimulation frequencies) could result in a larger system injectivity consequence of this risk, especially if not adequately mitigated.

8.4.3.7. Loss of Injectivity due to well interventions (MMV/integrity)

The Quest MMV strategy is based on minimal well intervention. Deep observation wells are not planned to penetrate the BCS and pressure and saturation monitoring in the BCS will be done by remote technologies like InSAR and 4D seismic respectively.

Interventions required for well integrity reasons are also included in this risk as Regulations are likely to require Cement Bond logging every 5 years.

8.4.3.8. Loss of Injectivity due to geochemical alteration of the reservoir (Halites)

Geochemical alteration of reservoir could decrease porosity and permeability, the drying effect of CO2 in the highly saline brine in BCS and/or reservoir fines could plug pore throats in the near well bore. Salts precipitated in the drying zone and/or fines may be remobilised by the velocity of the injected CO_2, resulting in reduction in permeability via plugging of pore throats.

The assessment is that this risk has a low probability for the following reasons:

1) Geochemistry: Current data suggests a low likelihood of occurrence as the only reactive component identified in the BCS is K-feldspar (5% vol) which is expected to continue to dissolve in the low pH flushed zone. The absence of mineral trapping will help sustained injectivity.
2) Halite precipitation: No reports of halite precipitation causing loss of injectivity exist in available literature. Modeling in TOUGHREACT suggested:
    a. the dry-out zone around injectors to be limited to 65m after 25 years of injection, whilst injection of low temperature CO_2 could reduce the dry out zone further by a factor 2
    b. the expected porosity reduction caused by halite precipitation to be less than 2 p.u.

    Halite precipitation in the dry-out zone should be dissolvable by fresh or low salinity water.
3) Fines migration. No evidence for fines or dispersed clays in the connected pore structure of the rock matrix have been found in thin sections that were cut to review possible causes of formation damage following the Radway 8-19 injection test.

8.5. Conformance

A loss of conformance exists if:

- *The observed distribution of CO_2 and pressure build-up inside the storage complex does not agree with model-based predictions within the range of uncertainty; or*
- *Knowledge of the actual storage performance is insufficient to distinguish between two classes of possible future performance: those that result in permanent stable storage of the target mass of CO_2 inside the BCS storage complex, and those that do not.*

These criteria are taken from the agreed Closure Plan.

8.5.1. Potential Consequences Due to a Loss of Conformance

A loss of conformance is not expected but if it does occur it may result in some of the following negative consequences:

- **Additional monitoring/data acquisition** activities required to re-establish conformance

- **Delay in site closure** until storage risks are understood to be acceptable
- **Loss of storage efficiency** if CO2 plumes spread further than expected

8.5.2. Potential Threats to Conformance

There are two potential threats that may cause a loss of conformance:

- **The original models are wrong** due to unexpected geological heterogeneities, or incorrect representation of the physical or chemical processes governing fluid transport, or insufficient analysis of uncertainties within the models
- **The monitoring is wrong** due to an unrecognised bias in either the acquisition, processing or interpretation of monitoring data.

8.5.3. Safeguards to Ensure Conformance

Several safeguards are in-place to reduce the likelihood or consequence of any unexpected loss of conformance. These safeguards include:

- **Basin-scale screening** studies ranked the top opportunities for geological storage of CO2 in Canada. Selecting a site within the top-ranked region minimises the risk of complex geology causing unpredictable storage behaviour.
- **Site selection** was based on a feasibility study of the pre-existing appraisal data to reduce the likelihood of insufficient injectivity, capacity or containment.
- **Site characterisation** based on a dedicated and comprehensive appraisal program including 2D and 3D seismic and an appraisal well at the center substantially improved the reliability of a broad range of subsurface models. These models will be updated in response to data acquired from each development well.
- **MMV Plan** provides monitoring of the CO2 plume and pressure build-up inside the BCS storage complex. An early indication of a potential loss of conformance will trigger corrective measures such as re-calibration of subsurface models, or re-distribution of CO2 injection between existing injectors, or if necessary to drill additional injectors to avoid unacceptably large CO2 plumes.

Time-lapse seismic will monitor the CO2 plume with a lateral resolution of 25-50 m and a sensitivity to 5-10% of continuous CO2 saturation within a zone at least 5-10 m thick. Down-hole pressure gauges within each injector and at one observation well (Redwater 3-4) will pressure build-up at these locations. InSAR measurements of surface displacements will provide a capability to map pressure build-up away from these wells with a lateral resolution of 1-3 km and a sensitivity of 30 to 300 kPa. The expected performance of these monitoring technologies will be assessed during the baseline monitoring (2012-2014) and early injection (2014-2019) periods. If these technologies do not perform as expected, then they will be discontinued and observation wells may be drill instead.

The residual risk of a loss of conformance associated with the possibility of all these independent safeguards failing is judged to be *low*.

8.5.4. Site specific risks to Conformance

The site specific conformance risks to conformance are identified and full risk descriptions and mitigation plans are maintained in the EasyRisk database. A bow-tie was not developed for this risk group as the conformance risks do not have a direct HSE related consequence, these are all captured under containment risks.

The following five risks will be addressed in the section below:

- Inability to Differentiate contamination from external sources
- Unexpected Plume (CO2) Migration outside of notification area
- Inability to Demonstrate Conformance (long term liability/handover)
- Unexpected pressure distribution that results in additional MMV requirement
- Unexpected Surface Heave that affects GW availability

8.5.4.1. Unexpected plume (CO2) migration outside of notification area

This risk is linked to the regulatory notification area (7x7 sections around each injector).

Quantification of CO2 plume sizes and associated sensitivity analysis was a specific deliverable of the Gen-4 models. The baffle ratio (kv/kh), porosity and permeability as well as the CO2-brine relative permeability are key drivers for the extent of CO2 migration in the storage formation during the injection period. The following end-of-injection (25 years, 100% uptime, 1.2 Mtpa) expectation plume sizes where estimated. In this assessment, plume extent is defined as the furthest distance CO2 has traveled away from the injector location:

- A three well case would be characterized by an average plume extent of 4300m;
- A four well development would have an average plume extent of 3700m
- A five injector case would have average plume lengths of 3250m.

Taking these findings into account it becomes apparent that, under the requirement for the CO2 to stay in the regulatory notification area, there are two potential mitigation strategies:

- The first and simplest option would be to increase the notification area.

- If the Quest project is not able to increase the notification area then it would be possible to ensure conformance while reducing CO2 footprint through drilling more injector wells.

For a detailed discussion of CO2 plume modeling impacting conformance see the GEN 4 IRM report [Ref 8.2]

8.5.4.2. Unexpected pressure distribution that results in additional MMV requirements

This risk specifically addresses the consequences of exceeding pressure predictions at the AOI boundary or third-party BCS legacy wells. It is expected that the consequences of this risk are limited to additional MMV requirements (at legacy wells) that were initially not planned for, a loss of credibility with the regulator that monitors the Project's performance against predictions and potential issued associated with the transfer of liability between closure and post closure.

Reservoir modeling indicates:

- This is a medium probability as it is only in the very low case reservoir models that pressures at the legacy wells are seen to increase to levels sufficient to lift BCS brine above the base of GWP in the unexpected event that these wells act as permeable conduits.
- In all reservoir modeling scenarios except the very low case with compartmentalization the BHP never exceeds values required to lift the BCS brine above the BGP.

Mitigations in place

- The injection well locations are sited a significant distance from legacy wells (21km minimum).
- DHPT monitoring will be in place in all injection wells
- The Redwater3-4 exploration well will be converted into a BCS pressure monitoring well. This is located just inside the southern edge of the AOI.
- InSAR monitoring is designed to provide maps of BSC pressure change across the AOI with an expected lateral resolution of 1-3 km and a sensitivity of 01-1 MPa.

8.5.4.3. Unexpected surface heave

This risk addresses the possibility that the maximum surface heave will greatly exceed model-based predictions of 60mm and become sufficiently large to affect the availability of groundwater resources. The Environmental Assessment recognized historic variations in groundwater levels are as much as 1m. Unexpected surface heave must therefore exceed 1m before the induced drop in free water levels inside existing groundwater wells exceeds historic variations. The likelihood of this is very low given the expected surface heave is substantially less than 1m.

8.5.4.4. Inability to differentiate contamination from external sources from project emissions

Initial groundwater quality has already been noted to in places exceed Alberta Tier 1 water quality guidelines. This is a farming community and with minor industrial activity and transport corridors (road, rail & pipeline) and the natural shallow geological conditions (coal, natural gas, arsenic bearing shales) these are all potential external sources of groundwater affects. The only reliable means of distinguishing these potential affects from potential Project affects is by using tracers specific to the Project. There are two types of tracers those that tag the BCS brine and those that tag the injected CO2.

- The Basal Cambrian Sand (BCS) formation fluid geochemistry is unique. A groundwater monitoring program has been designed to carefully verify that even small quantities of BCS brine have not entered the groundwater. This document shows a range in identifiable BCS formation brine tracer detection limits from 0.005% to 10% of in a given Belly River Group (BRGP) formation fluid. Others are still under review, primarily isotopes, and early indications are good for extra lower end of detection limit range tracers. The most effective tracer observed are the Halogen: Halogen and Halogen: Sodium Ratios within the BCS formation fluid.
- Perfluorocarbons (PFC) are the recommended option from the list of available CO2 tracers due to their high degree of partitioning into the CO2 phase, high stability, limited interaction with the subsurface environment. PFCs stand out from the rest in terms of availability, limited interaction with minerals and aqueous phase, longevity in the subsurface, cost and ease of commercial deployment. Detection limit for PFCs is 10 parts per trillion.
- Shell Canada is planning to utilize the LOSCO2 monitoring system, which is a line-of-sight gas mapping system to detect anomalous CO2 gas flux. Any anomalous CO2 flux indications will trigger sample collection analysis and analysis for the presence of Project -specific tracers.

8.5.4.5. Inability to Demonstrate Conformance

The Closure plan submitted as part of the approved Sequestration Lease provides for the first time a framework for demonstrating conformance. This approved closure plan provides:

- A process for issuing a site closure certificate at the end of the closure period provisional on demonstration of containment and conformance. These storage performance criteria are defined in this document.
- This document also allows for updates every three years for both subsurface modeling and monitoring plans. This is an effective means of mitigating the risk that conformance cannot be demonstrated.
- The Closure Plan will be updated to reflect any additional provisions that may be the result of the ongoing Regulatory Framework Assessment.

All subsurface risks are summarised and linked to TESLA in the following documents:

- [Ref 8.9] Containment
- [Ref 8.10] Capacity
- [Ref 8.11] Injectivity
- [Ref 8.12] Conformance

9. WELL ENGINEERING AND PRODUCTION TECHNOLOGY

9.1. Introduction

9.1.1. Well Types

Three well types are considered for the Quest CCS project: the CO2 injection wells (IW), the deep MMV wells (DW) and the shallow groundwater MMV wells (GW). The design considerations for these three well types are further described in the Quest Conceptual Completion Design and Quest Well Functional Specification documents [Ref. 9.1, Ref 9.2], but this section gives an overview of the well related aspects of the Quest CCS project. Well schematics can be seen in APPENDIX 5.

9.1.2. Well Integrity

The Quest CCS project well design followed a risk-based approach. A specific well bowtie was built to ensure the well design would lower the risk of loss of containment from the BCS storage complex to ALARP (see [Ref. 9.1] for more details). Each barrier and mitigation of this bowtie is included in the well and well operations design. In particular specific emergency well control processes will be developed by Well Engineering and Completion & Well Intervention services, and a CO2-specific Well Control Emergency Response Plan has been developed with a specialised third party (Wild Well Control).

9.2. Road and Pad Designs

Each pad will be designed to limit land disturbance by using pre-existing access or clearings whenever possible. The locations of these well pads are primarily based on reservoir conformance issues, distance to towns, houses and sensitive areas, reservoir quality of vertical target, distance from the edge of the 3D seismic survey and distance to the pipeline. Well pads for injection wells are expected to range in size 130 m by 130 m and are expected to be similar to those of recently drilled Well 8-19-59-20W4. Depending on the number of required injection wells, the following locations are considered, by order of preference:

- 7-11-59-20W4
- 5-35-59-21W4
- 15-16-60-21W4
- 10-6-60-20W4
- 15-1-59-21W4
- 12-29-60-21W4
- 12-14-60-21W4

Each injection well pad will include: 1 injection well (IW), at least 1 groundwater MMV well (GW) and possibly 1 deep MMV well (DW). The injection well pad will have a connection to the power grid and an enclosed skid to house computers for operating MMV instruments. SCADA communication system will be installed for the operational and safety critical elements (e.g. ESD) and an independent communication system will continuously transmit the large volume of MMV data to Scotford and Calgary centre APPENDIX. *Figure 9-1 Conceptual Injection Wellpad Layout.*

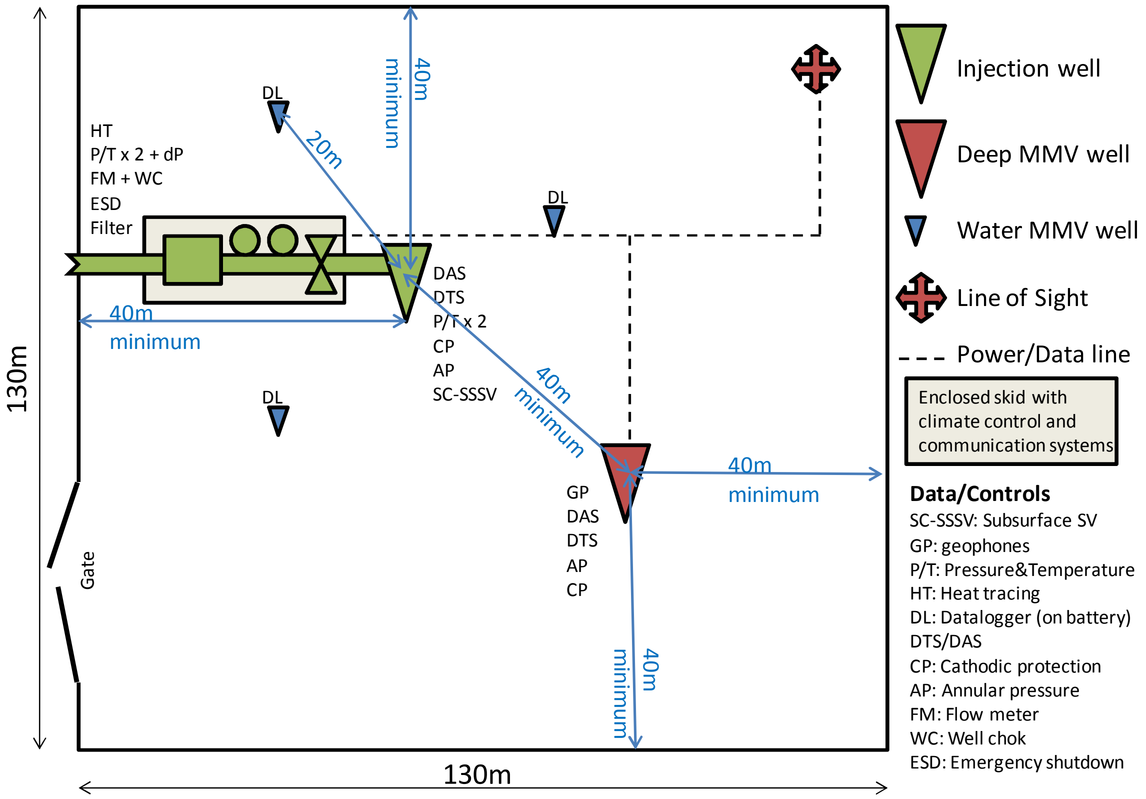


Figure 9-1 Conceptual Injection Wellpad Layout

9.3. Injector Well Design

9.3.1. Objectives

The number of injection wells ranges from 3 to 8 with a base case of 5. Radway 8-19-59-20W4 has already been drilled and is the first well planned as a commercial injector. Each injection well has the following objectives:

- Ensure well integrity across the well operating envelope, via the casing design, the completion design, the material selection and the well intervention procedures. The design envelope is as follows:
  - Wellhead pressures ranging from 3.5 to 14 MPa

- Bottomhole pressures ranging from 20 to 32 MPa
- Wellhead temperatures ranging from -10 to +18 degC
- Bottomhole temperatures ranging from +15 to +60 degC

- Ensure target injection rate is achievable with an extra capacity built in, to ensure the total available CO_2 flow can be injected even if one Injection Well is shut-in
- Ensure all planned MMV activities can be carried out by including monitoring devices as part of the completion and enabling workovers to be carried out regularly for specific MMV tasks.

9.3.2. Casing Design

The injection wells will be vertical. Horizontal wells remain an option only in the case of a high well count development (>8 wells). More details are available in [Ref. 9.3 and 9.4].

The casing scheme will follow Radway 8-19 design and will consist of:

- A L80 surface casing set below the Base Ground Water Protection zone (BGWP) and cemented to surface, in order to isolate and protect the BGWP
- A L80 intermediate casing set to below the bottom seal and cemented to surface so that the three seals are covered with a cemented string
- A main casing set in the Precambrian and cemented to surface with MMV equipment (DTS/DAS optic fibre). There is also an option to include a RTCI system across the Winnipegosis and/or Cooking Lake formation for pressure monitoring. This casing will be L80 with LTC connections but the bottom part exposed to CO_2 and potentially formation brine will be 25Cr and premium connections. The bottom part of Radway casing is 22Cr but the specifications were increased for future wells due to the high salinity of the BCS brine found in this well.

The cement will be Portland based and specifically formulated to ensure no shrinkage while setting, higher ductability and higher durability over the project lifetime and therefore maximize well integrity

9.3.3. Completions Design

The base case well size assumes 4.5″ tubing, which enables the target injection rate to be achieved, plus extra capacity, while allowing for all MMV activities to be carried out. Since the injected CO_2 is dry, the current tubing selection is for L80 with premium connections, for the following reasons:

- The inclusion of a check valve at the bottom of the completion is under evaluation and could potentially prevent any backflow of brine up the completion.
- However, this choice is still under evaluation since there is currently no regulatory requirement for a subsurface safety valve and that its implementation could increase the overall risk [Ref. 9.5].
- If no check valve is included in the final completion, the need for corrosion resistant tubing will be re-evaluated.

The completion will be equipped with a permanent downhole pressure / temperature gauge for MMV.

- If a check valve is included in the completion, it is proposed to set it just above the downhole pressure/temperature gauge, in order to benefit from easy fall-off tests when the wells are shut-in.

The packer and the packer tail will be CRA coated in order to resist potential exposure to CO2 and formation brine. Workovers will be primarily done by killing the well on a plug set in the packer tail.

The annular fluid design is ongoing but will ensure well integrity is maintained in case of a leak and should therefore be oil-based.

The wellhead will be rated to 5,000 psi and all wetted parts will be CRA coated, in the same way as the wellhead installed on Radway 8-19.

9.4. Deep MMV Wells

9.4.1. Objectives

MMV commitments state that a minimum of three DWs wells will be drilled. The DWs have the following objectives:

- Monitor pressure evolution above the BCS storage complex, in the Winnipegosis or the Cooking Lake aquifers, to give early indication of loss of containment in the vicinity of the IWs.
- Monitor microseismic activities in the BCS storage complex

The number and locations of the DWs depending on the number of injection wells is further described in section 5.3.1.3.

9.4.2. Design

Two designs are currently considered depending on the final location and objectives of the MMV wells. Schematics of these designs are given in APPENDIX 5:

- The first design considers a 5″ L80 cemented surface casing protecting the BGWP and a 2 7/8″ L80 cemented casing running to the target formation (Winnipegosis or Cooking Lake). This casing will be perforated to monitor pressure evolution in the target formation and no tubing will be required as no flow is expected.
- The second design considers a 7″ L80 cemented surface casing protecting the BGWP, a 5″ L80 cemented casing running to the target formation and a 2 7/8″ L80 cemented tubing with geophones set outside of it. The 5″ casing should be perforated in the target formation so that this MMV well can achieve both pressure monitoring and microseismic monitoring

The final design and location of the deep MMV wells will be made after drilling and testing of IW 2 and 3.

9.4.3. Redwater 03-04-57-20W4

Redwater 03-04-57-20W4 was drilled in 2009 in the Quest AOI as a BCS appraisal well. It is currently suspended but it is planned to convert this well for pressure monitoring in the BCS [Ref. 9.6]. It is the only monitoring well penetrating the BCS in the base MMV plan.

9.5. Shallow Groundwater MMV Wells

9.5.1. Objectives

The MMV commitments state that 3 GWs will be drilled per IW with and at least one GW will be located on each injection well pad. The shallow GW have the following objectives:

- Monitor pressure and water chemistry changes in the BGWP aquifers near the injectors
- Monitor pressure and water chemistry changes in the BGWP aquifers near the BCS legacy wells

9.5.2. Design

Two designs are currently considered depending on the final objectives of the GWs:

- The first design will consist of a conductor and a cemented steel casing. A pilot hole will enable to confirm the target formation, that will be completed with pre-packed screens
- The second design consists of a simple PVC pipe cemented in place with the target formation completed with pre-packed screens

Permanent conductivity gauges will be installed and the wells will be regularly sampled.

9.6. Legacy Wells

Several third party wells have already been drilled in the Quest AOI. Amongst these, four penetrate the BCS formation and will therefore be subjected to specific attention to ensure they do not result in a loss of containment from the BCS storage complex. Since they are located far away from the CO_2 plume, the base plan monitoring will consist in drilling GW near their location to monitor for pressure or water chemistry changes within the BGWP. If such change is detected and the decision to intervene is taken, the intervention plan will include re-entering these wells and isolating the BGWP. More details are available in [Ref. 9.7].

9.7. Drilling Operations

The first IW is already drilled (Radway 8-19). The second and third IW will be drilled and tested in summer 2012. If required, two additional IWs will be drilled in summer 2013.

The DWs and GWs will be drilled in summer and fall 2013. The GWs associated with IW#2, IW#3 and the four legacy wells will be drilled in summer 2012.

All wells will be drilled through the BGWP with water-based mud as per current regulations. The intermediate and final holes will be drilled with OBM in order to maximize borehole conditions prior to cementing, and minimize target formation impairment.

Coring, sampling and logging operations will be included in the drilling of these wells to reduce subsurface uncertainties.

9.8. Flow Assurance

Following the main Flow Assurance study performed on the integrated system (see section 7), several mitigation strategies have been implemented in the design and operation procedures:

- *Two-phase flow*:
  There is no risk related to the presence of two-phase flow in the wellbore (steady-state injection, start-up or shut-in). In particular the bottomhole pressure will not be subjected to erratic changes due to phase change in the wellbore
- *Hydrates*:
  The CO_2 will arrive at the well choke in liquid state in most of the considered scenarios. The well choke will induce a pressure drop that could result in a phase change of the CO_2 to gas under certain conditions, and result in a cooling effect. However, the well choke and the well will operate at all time outside of the hydrate formation envelope, thanks to the water content of the CO_2 ranging from 4 to 6 lbs/MMscf

A chemical injection port will be included upstream of the chokes to allow for mitigation of unplanned hydrate formation and/or tracer injection

- *Solids in the injection stream:*

  Particle filters sized to at least 5 microns will be installed at each well pad to protect the BCS formation from impairment due to unexpected solids in the CO2 stream.

9.9. Completion Operations

The completion of each well will follow its drilling.

- A 1 m interval in the upper BCS may be perforated in order to perform a minifrac test to confirm fracture pressures.
- The wells will be perforated over approximately 30m over the base of the BCS, using large TCP-carried high performance guns in underbalanced conditions in order to maximize penetration and minimize skin.
- Following the perforation operations, an acid stimulation and/or a N2 clean-out will enable to clean drilling and perforation damages in order to further reduce skin.
- The wells will be then tested with a water injection test using water or brine filtered at 5 microns. Once IW#2 and IW#3 have been tested, the final number of required injectors will be determined and the decision whether to drill IW#4, IW#5 and their associated MMV wells in 2013 will be taken.
- The wells will be temporarily abandoned until the start of injection. All wells temporarily abandoned will therefore need to be recompleted prior to the start of injection.

9.10.Wells Start-up

Prior to the start-up, the wells will be displaced to CO2 with a CO2 truck, in order to perform the initial start-up (from water to CO2) in a controlled and independent fashion.

The wells will be then started after HMU3 turnaround, in December 2014. A first injector (Radway 8-19) will be progressively ramped up in January 2015 until stable injectivity at target rate is achieved. An interference test will follow, up to the HMU2 turnaround in Q2 2015. Afterwards, the other IWs will be started sequentially to ensure they all reach stable injectivity before Q4 2015 so that the contractual sustained operations can be achieved before the deadline of end 2015. More details are available in [Ref. 9.8].

9.11.Wells Interventions

Several wells interventions are planned during the lifetime of the project:

- Logging operations: as part of the MMV plan and regulatory requirements, several logging tools will be run in the well (see the MMV section for more details)

- Workover operations: as part of the MMV plan, regular workovers could also be performed (e.g. to perform a VSP). The completion design will therefore ensure the well can be killed on a plug in the packer tail and the tubing un-set and re-set.
- If killing on formation is required, a sand plug could be set across the perforation with a gel plug on the top of it. This will enable killing the well without damaging the formation and can be reversed with a N2 clean-out.

Specific operational procedures will be put in place to ensure the specific risks related to intervening on a CO_2 well are mitigated.

9.12. Wells Abandonment

The abandonment of the Quest wells will follow a phased approach that will consist of:

- An observation period following the stop of injection, keeping in-well monitoring of the BCS possible to support conformance
- The isolation of the BCS followed by another observation period, in order to support containment of the BCS storage complex while keeping the ability to re-enter the well if required
- The final subsurface and surface abandonment of all wells, where all in-well MMV will stop

Figure 9-2 shows the injection well status during the three phases of abandonment.

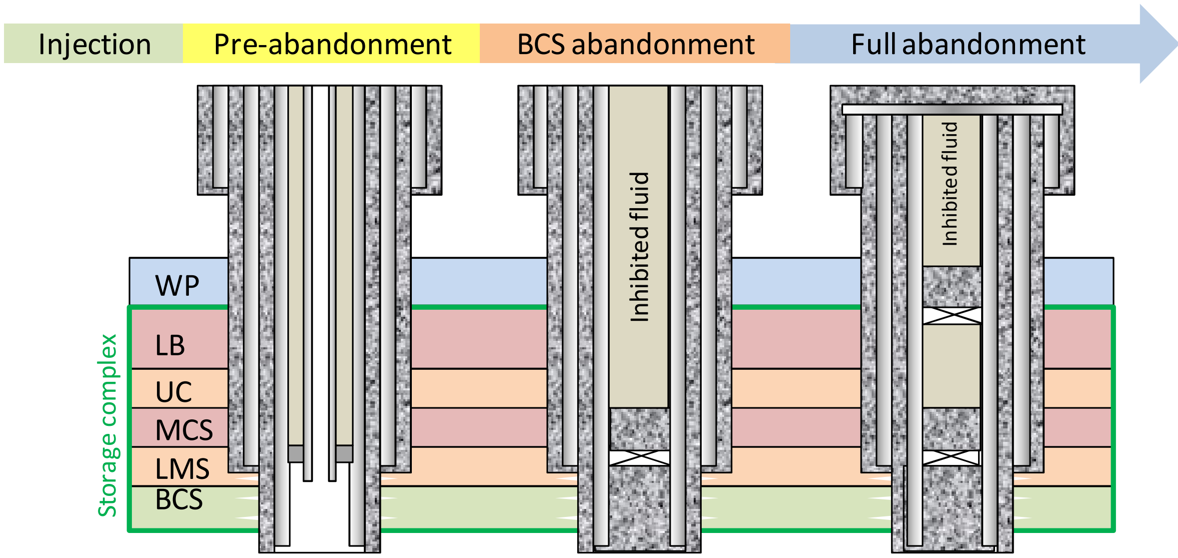


Figure 9-2 Injection Well Schematic During the Three Phases of Well Abandonment

10. MEASUREMENT, MONITORING AND VERIFICATION (MMV)

The MMV Plan [Ref 10.1] is central to storage risk management as it provides the means of verifying expected storage performance and, if necessary, providing early warning of any potential threat to allow implementation of effective control measures. The two primary objectives of MMV for the Quest CCS Project are:

- **Ensure Conformance** to indicate the *long-term security* of CO2 storage, *i.e.*
    - Show pressure and CO2 development *inside* the storage complex are consistent with models and, if necessary, calibrate and update these models.
    - Evaluate and, if necessary, adapt injection and monitoring to optimize storage performance.
    - Provide the monitoring data necessary to support CO2 inventory reporting.
- **Ensure Containment** to demonstrate the *current security* of CO2 storage, *i.e.*
    - Verify the absence of any environmental effects *outside* the storage complex.
    - Detect early warning signs of any unexpected loss of containment.
    - If necessary, activate additional safeguards to prevent or remediate any significant environmental impacts as defined by the Environmental Assessment.

Well-established industry practices for Well and Reservoir Management and Environmental Monitoring provide the key capabilities necessary to fulfill these requirements.

10.1.Area of Review

MMV will operate within an Area of Review (AOR) which has sufficient extent to include any potential impacts due to CO_2 storage including the displacement of brine. The initial AOR is equal to the initial Sequestration Lease Area. Observed storage performance will be used to verify the size and shape of the AOR and, if necessary, the AOR will be updated as part of a revised MMV Plan submitted to regulatory agencies every 3 years.

10.2.Domains of Review

MMV will monitor four distinct environmental domains.

- **Geosphere**: The subsurface domain below the base of the groundwater protection zone including the BCS storage complex. The geological storage complex comprises a primary storage formation (Basal Cambrian Sands, BCS), a first seal (Middle Cambrian Shale, MCS), a second seal (Lower Lotsberg Salt), and an ultimate seal (Upper Lotsberg Salt). Above the storage complex, the geosphere also contains two addition deep saline aquifers, the Winnipegosis and the

Cooking Lake, that provide potential opportunities for MMV. Proven oil resources exist within the Leduc, Nisku and Wabamun formations and proven gas resources within the Nisku, Mannville Group and Colorado Group.

- **Hydrosphere**: The subsurface domain within the groundwater protection zone where water salinity measured as the concentration of total dissolved solids is less than 4,000 milligrams per litre. The Alberta Environment (AENV) Water Act defines saline groundwater as that containing greater than 4000 milligrams per litre (mg/L) total dissolved solids.
- **Biosphere**: The domain containing ecosystems where living organisms exist.
- **Atmosphere**: The local air mass where any changes to air quality matter and the global air mass where any changes influencing climate matter.

10.3. Timeframe of Review

MMV activities will be adapted through time to meet the different requirements during five distinct phases of the Project lifecycle:

- **Pre-Injection Phase**: Monitoring tasks are identified, monitoring solutions evaluated and selected, risks are characterized, and baseline monitoring data are acquired.
- **Injection Phase**: Monitoring activities are undertaken to manage conformance and containment risks, and, if necessary, are adapted through time to ensure their continuing effectiveness.
- **Closure Phase**: In accordance with the Closure Plan (Shell Canada Limited n.d.), some monitoring activities will continue during this phase to manage containment risk and to demonstrate storage performance is consistent with expectations for long-term secure storage. The duration of the closure phase before transfer of liability will be determined according to the strength of evidence obtained from the monitoring program that actual storage performance conforms against the predicted performance. Site closure activities will be executed including facilities decommissioning, pipeline abandonment and reclamation, and wells abandonment and reclamation.
- **Site Closure**: Shell will apply for a Site Closure Certificate following the execution of site closure activities. Shell anticipates receipt of a Site Closure Certificate 10 years post injection cessation, provided there are no significant issues that arise from Project operations and that storage performance and CO_2 and brine containment in the BCS storage complex are demonstrated to the satisfaction of the Crown in accordance with pre-agreed criteria.
- **Post-Closure Phase**: Closure certificate is acquired and liability transferred from Shell to Crown. The Crown may elect to continue some monitoring activities for

reasons such as scientific research to understand long-term storage mechanisms for CO2 within the BCS formation.

10.4.Timeframe of Updates

The MMV Plan will be subject to annual performance reviews and, if necessary, adaptation in response to new information gained from:

- Site-specific technical feasibility assessments
- Baseline measurements during the pre-injection period
- Monitoring during the injection and closure periods

Shell will provide an annual report on MMV performance and submit a revised MMV Plan to regulatory agencies every three years, coincident with the required submission of the Closure Plan to Alberta Energy.

10.5.General Design Considerations

The MMV Plan is designed according to the following principles that build on the CO2QUALSTORE guidelines published by DNV:

- **Regulatory-Compliance**: The MMV Plan will comply with regulatory requirements as they mature.
- **Risk-Based**: Monitoring tasks are identified through a systematic risk evaluation based on the collective expert judgment and validated independent experts. The scope and frequency of monitoring tasks depend on the outcome of this risk assessment. Project safeguards are implemented to reduced storage risks to as low as reasonably practicable.
- **Site-Specific**: Monitoring technologies are selected for each monitoring task based on the outcome of site-specific feasibility assessments and then custom-designed to ensure optimal monitoring performance under local conditions particular to the storage site.
- **Adaptive**: The performance of the storage site and the monitoring systems are continuously evaluated. Contingency Plans exist with clear trigger points for implementing control measures to ensure effective responses to any unexpected events.

10.6.Risk Management Philosophy

There are three principle parts to the framework developed for storage risk management (*Figure 10-1 Framework for Storage Risk Management)* to support the proposed timeline for site closure (*Figure 10-2 Proposed Timeline for Site Closure Activities*).

- **Site Characterisation**: This is the initial risk assessment and implementation of initial safeguards through site selection, site appraisal, and engineering concept selections. The Directive 65 regulatory application describes the outcome of this process.

- **MMV**: This provides an additional risk assessment and implements additional safeguards through monitoring to verify the expected storage performance and, if necessary, trigger appropriate control measures.
- **Performance Reviews & Site Closure**: Annual performance reviews provide a continuation of the risk management process during the injection and closure phases of the project to support site closure and transfer of long-term liability. The Closure Plan appended to the Directive 65 application describes this process in detail [Ref 10.2].

The MMV Plan was designed according to this risk management framework.

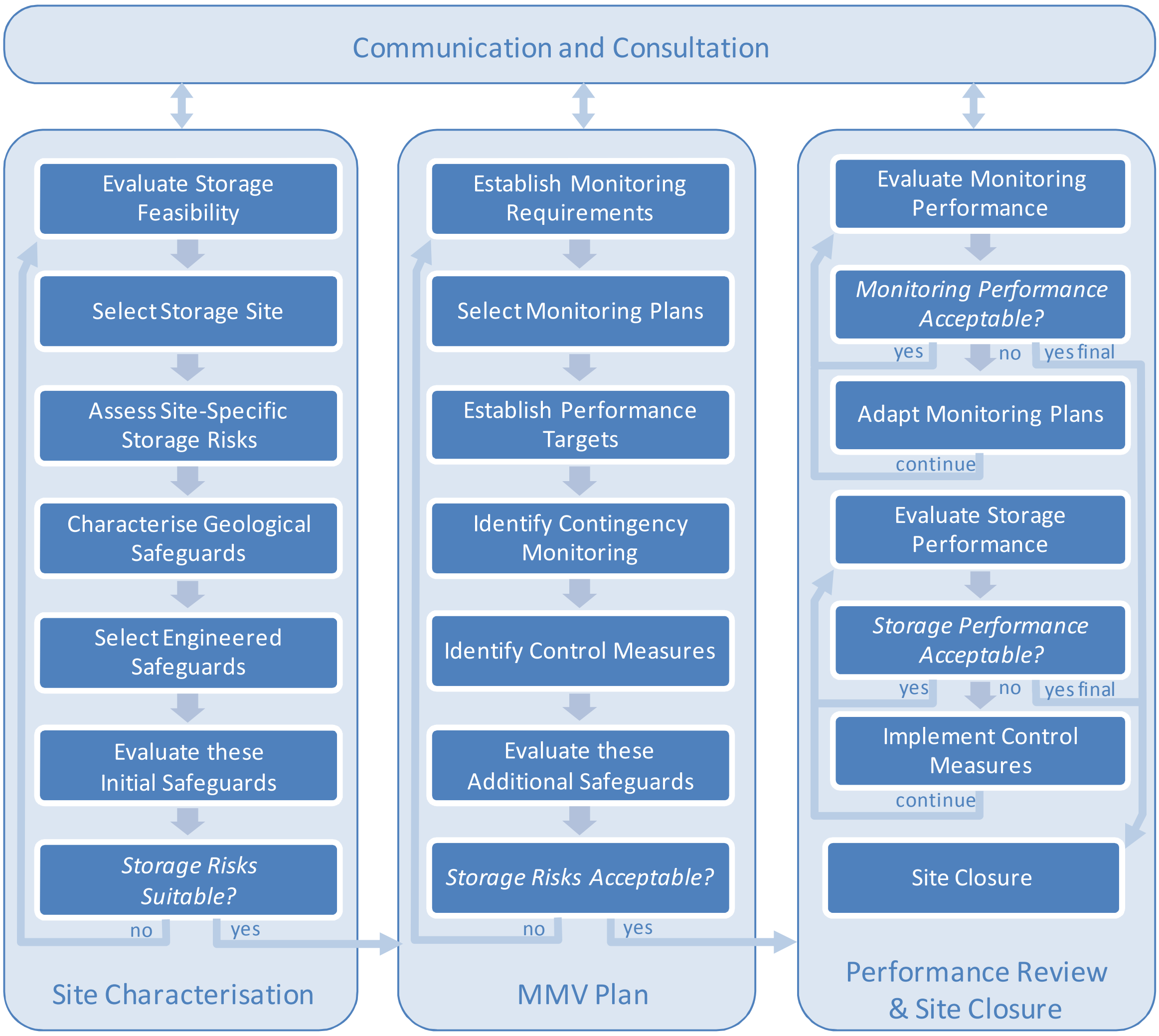


Figure 10-1 Framework for Storage Risk Management

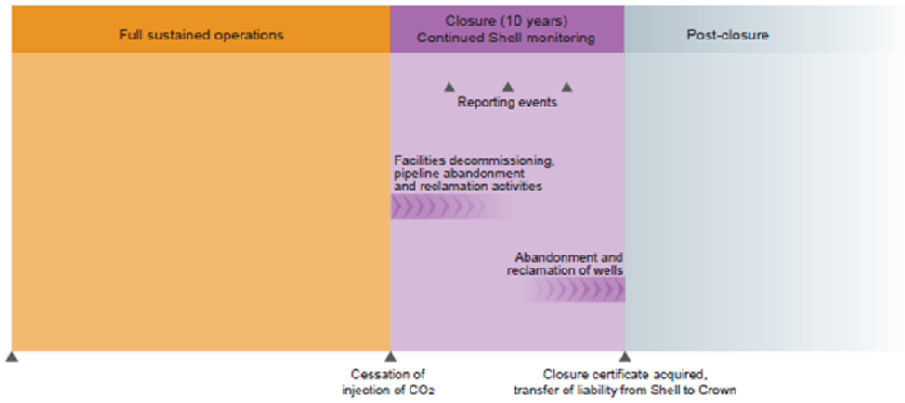


Figure 10-2 Proposed Timeline for Site Closure Activities

10.7. MMV Operating Philosophy

MMV operations will be subject to annual performance reviews against clear performance targets for reach monitoring system. If necessary, MMV operations will be adapted according to ensure acceptable storage and monitoring performance. Contingency monitoring plans exist to mitigate any unexpected under-performance of a monitoring system. Control options exist to mitigate any potential loss of conformance or containment. Expert judgement from subsurface engineers is required to ensure monitoring information properly supports storage management decisions throughout the baseline, injection and closure phases of the project.

10.8. Scope of Work

Some commitments for monitoring already exist (*Table 10-1 MMV Commitments Made in June 2010 in Response to Supplemental Information Requests*) based on responses provided to Requests for Supplemental Information following the submission of the Conceptual MMV Plan to regulatory authorities in November 2010 [10.3].

The schedule of monitoring activities provides coverage through time and across the AOR within each of the environmental domains using a range of independent monitoring systems (*Table 10-2 Summary of the Monitoring Plan for the Geosphere, Hydrosphere and Atmosphere,*

Table 10-3 Summary of the Monitoring Plan for Deep Observation Wells and CO2 Injectors, Figure 10-3 Schedule of Monitoring Activities). The diversity of monitoring technologies mitigates the risk of any one technology failing.

Table 10-1 MMV Commitments Made in June 2010 in Response to Supplemental Information Requests

MMV Plan Updates
1. Updates submitted to regulators before commencing baseline monitoring in 2012, and then every 3 years
Wells
2. Distributed temperature sensing system outside the production casing on all injectors to verify well integrity
3. Deep monitoring wells (3), drilled from injection well pads to monitor Winnipegosis pressure changes
Geosphere
4. Time-lapse seismic: First 3D VSP then 3D surface seismic designed to monitor each CO2 plume
5. Remote sensing: Monthly InSAR designed to monitor pressure build-up inside the storage complex
Hydrosphere
6. Groundwater monitoring wells (3 per injector): Water electrical conductivity and water chemistry
Biosphere
7. Remote sensing: Annual multi-spectral imaging designed to detect environmental changes
Atmosphere
8. Line-of-sight CO2 flux monitoring field trial at Radway 8-19 starting Q3 2011 to measure any CO2 emissions

Table 10-2 Summary of the Monitoring Plan for the Geosphere, Hydrosphere and Atmosphere

Monitoring	Coverage	Pre-Injection	Injection	Closure
Atmosphere				
Line-of-sight CO2 gas flux monitoring[a]	Within 6 km of every injector	Continuous	Continuous	Continuous
Biosphere				
Remote Sensing[a]	Entire AOR	Twice a year	Twice a year	Twice a year
Soil salinity monitoring	Discrete locations across the AOR	Every year	Every year	Every 2 years
Soil pH monitoring	Discrete locations across the AOR	Every year	Every year	Every 2 years
Natural tracer monitoring	Discrete locations across the AOR	Every year	Every year	Every 2 years
Artificial tracer monitoring	Discrete locations across the AOR	Every year	Every year	Every 2 years
Hydrosphere				
Down-hole pH monitoring[a]	Project groundwater wells	Continuous	Continuous	Continuous
Down-hole electrical conductivity monitoring[a]	Project groundwater wells	Continuous	Continuous	Continuous
Natural tracer monitoring[a]	Project and Private groundwater wells	Every year	Every year	Every 2 years
Artificial tracer monitoring	Project and Private groundwater wells	Every year	Every year	Every 2 years
Geosphere				
Time-lapse 3D vertical seismic profiling[a,b]	Within 600 m of every injector	2013	2016 2018	None
Time-lapse 3D surface seismic[a]	Every entire CO2 plume	2010	2022 2029 2039	2048
Interferometric Synthetic Aperture Radar[a]	Entire AOR	Monthly	Monthly	Monthly

[a] *A commitment made in response to Supplement Request for Information.*

[b] *Baseline data will be acquired using conventional down-hole geophones and the DAS system, subsequent surveys will be acquired with the DAS system only.*

Table 10-3 Summary of the Monitoring Plan for Deep Observation Wells and CO2 Injectors

Monitoring	Pre-Injection	Injection	Closure
WPGS Observation Wells			
Down-hole pressure-temperature monitoring [c]	None	Continuous	Continuous
Down-hole microseismic monitoring (8-19 well pad only)	None	Continuous	None
Cement bond log	Once	None	None
BCS Observation Well			
Down-hole pressure-temperature monitoring	None	Continuous	Continuous
Cement bond log	Once	None	None
Injectors			
Well-head pressure-temperature monitoring [b]	None	Continuous	Continuous
Time-lapse ultrasonic casing imaging	Once	Every 5 years	Every 10 years
Time-lapse electromagnetic casing imaging	Once	Every 5 years	Every 10 years
Time-lapse casing calliper logs	Once	Every 5 years	Every 10 years
Mechanical well integrity testing (packer isolation test)[a] and tubing calliper log	Once	Every year	Every 3 years
Injection rate monitoring [b]	None	Continuous	None
Distributed temperature sensing [c]	None	Continuous	Continuous
Down-hole pressure-temperature monitoring	None	Continuous	Continuous
Distributed acoustic sensing	None	Continuous	Continuous
Cement bond log	Once[a]	Every 5 years[b]	Every 5 years
Annulus pressure monitoring [b]	None	Continuous	Continuous
Artificial tracer injection	None	Quarterly	None
Routine well maintenance [d]	Every 6 months	Every 6 months	Every 6 months

[a] *A D51current regulatory commitment for Class III wells.*

[b] *A possible future D51 regulatory commitment for Class III wells (current requirement for Class I wells).*

[c] *A commitment made in response to Supplement Request for Information.*

[d] *A maintenance task related to the wells, included in this table for completeness.*

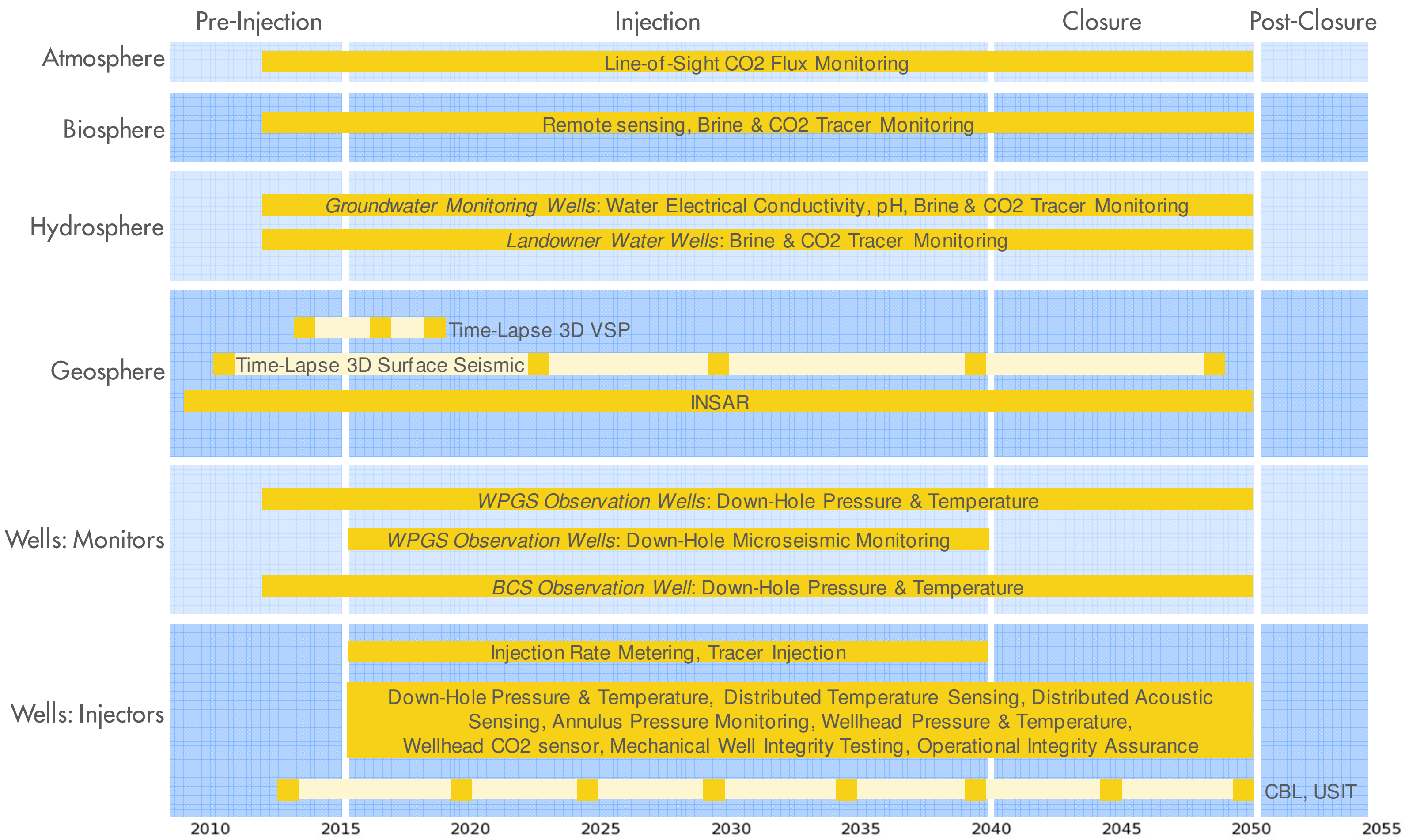


Figure 10-3 Schedule of Monitoring Activities

This base-case MMV Plan involves additional Project wells:

- 3 deep observation wells drilled into the Winnipegosis Formation to support containment monitoring.
- 12 shallow wells drilled down to the base of groundwater protection to support groundwater monitoring.

The number and location of these additional Project wells depends on the development scenario (

Table 10-5 The Type of Well Pad Required at Each Injector Location Depends on the Development Scenario and Figure 10-4 Maps Showing the Location of Observation Wells for the Different Development Scenarios. Coordinates show kilometers in the NAD27UTM Zone 12N datum summarize the layout of well pad types under each development scenario.

Table 10-4 The Number and Location of Project Wells That Support the MMV Plan Depend on the Development Scenario). Consequently three distinct types of injection well pads are required to support the MMV Plan. These are characterised by the different wells present on each type of well pad:

- **Type 1**: Includes:
  - Injection well
  - Project groundwater well
- **Type 2**: As Type 1, but also includes:
  - WPGS observation well with down-hole pressure monitoring
- **Type 3**: As type 2, but also includes:
  - Down-hole microseismic monitoring within the WPGS observation well

Table 10-5 The Type of Well Pad Required at Each Injector Location Depends on the Development Scenario and *Figure 10-4 Maps Showing the Location of Observation Wells for the Different Development Scenarios. Coordinates show kilometers in the NAD27UTM Zone 12N datum* summarize the layout of well pad types under each development scenario.

Table 10-4 The Number and Location of Project Wells That Support the MMV Plan Depend on the Development Scenario

	3 Injectors	4 Injectors	5 Injectors	8 Injectors
Injectors	8-19-59-20W4 7-11-59-20W4 5-35-59-21W4	8-19-59-20W4 7-11-59-20W4 5-35-59-21W4 15-16-60-21W4	8-19-59-20W4 7-11-59-20W4 5-35-59-21W4 15-16-60-21W4 10-6-60-20W4	8-19-59-20W4 7-11-59-20W4 5-35-59-21W4 15-16-60-21W4 10-6-60-20W4 15-1-59-21W4 15-29-60-21W4 12-14-60-21W4
BCS Observation Wells	Redwater 3-4	Redwater 3-4	Redwater 3-4	Redwater 3-4
WPGS Observation Wells	1 well on each of these 3 well pads: 8-19-59-20W4* 7-11-59-20W4 5-35-59-21W4	1 well on each of these 3 well pads: 8-19-59-20W4 5-35-59-21W4* 15-16-60-21W4	1 well on each of these 3 well pads: 8-19-59-20W4 5-35-59-21W4* 10-6-60-20W4	1 well on each of these 3 well pads: 8-19-59-20W4 5-35-59-21W4* 15-16-60-21W4
Project Groundwater Wells	9 wells in total 3 next to injectors 4 next to legacy wells 2 inside AOI	12 wells in total 4 next to injectors 4 next to legacy wells 4 inside AOI	15 wells in total 5 next to injectors 4 next to legacy wells 6 inside AOI	24 wells in total 8 next to injectors 4 next to legacy wells 12 inside AOI

**Denotes the single WPGS observation well equipped with down-hole geophones for microseismic monitoring.*

Table 10-5 The Type of Well Pad Required at Each Injector Location Depends on the Development Scenario

Development Scenarios

3 Injectors	4 Injectors	5 Injectors	8 Injectors	Injection Well Pads
Type 3	Type 2	Type 2	Type 2	8-19-59-20W4
Type 2	Type 1	Type 1	Type 1	7-11-59-20W4
Type 2	Type 3	Type 3	Type 3	5-35-59-21W4
	Type 2	Type 1	Type 2	15-16-60-21W4
		Type 2	Type 1	10-6-60-20W4
			Type 1	15-1-59-21W4
			Type 1	15-29-60-21W4
			Type 1	12-14-60-21W4

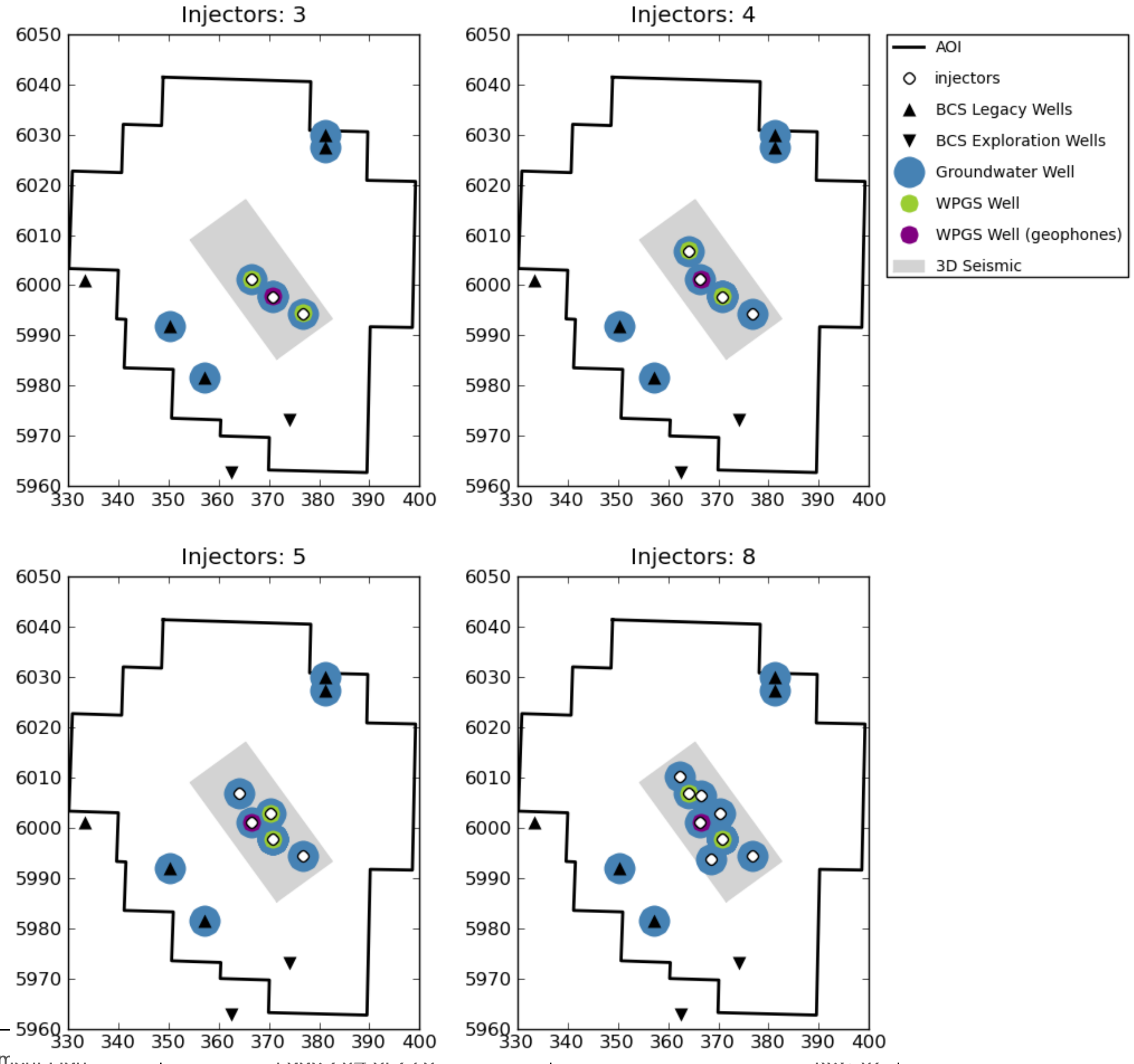

Injectors: 3
Injectors: 4
Injectors: 5
Injectors: 8
6050
6040
6030
6020
6010
6000
5990
5980
5970
5960
330 340 350 360 370 380 390 400
AOI
injectors
BCS Legacy Wells
BCS Exploration Wells
Groundwater Well
WPGS Well
WPGS Well (geophones)
3D Seismic

Figure 10-4 Maps Showing the Location of Observation Wells for the Different Development Scenarios. Coordinates show kilometers in the NAD27UTM Zone 12N datum

11. NEW TECHNOLOGY APPLICATION

[Ref 11.1]

11.1. Capture

For the Capture and pipeline portions of the Quest scope use of novel technology is being identified, tracked and mitigated within the Flawless Project Delivery Program. Novelty and complexity is Q08 within the program and novelty items are being tracked through all project phases until project closeout.

11.1.1. Amine capture technology

There is no new technology applied in the CO2 capture process. It is in-line with conventional amine processes at hydrocarbon facilities.

11.1.2. CO2 Compression technology

An 8-stage integrally-geared CO2 compressor will be used for the Quest Project. This is not a novel technology, however it has not been used by Shell in the past. The vendor (MAN Turbo) has successfully built and put this machine in service several times in the past.

The Dakota Gasification project, located in Beulah, ND, currently operates three MAN Turbo 8-stage integrally geared centrifugal compressors, in CO2 compression service. Other than the fact that they have air-cooled intercoolers whereas the current Quest design basis is water-cooled intercoolers, those compressors are very similar in size and performance parameters to the compressor required for the QUEST project, and they are the same model. These compressors have a good operating record and were visited by project team members in May 2010.

There are no significant risks seen in applying an integrally-geared centrifugal compressor for the CO2 compression duty on the QUEST project, and this technology is by far the most logical choice.

Refer to Quest document number 07-1-MR-8226-0001 “Integrally Geared Centrifugal CO2 Compressor Qualification” for the detailed report on this issue, done by Chris Gilmour, TA1 rotating equipment [Ref 4.8].

11.2.Pipeline

There is no new technology being applies to the pipeline scope of the project

11.3.Subsurface

11.3.1. Reservoir Modeling

Subsurface modeling of both, the migration of the CO_2 plume as well as the extent and magnitude of the pressure increase in the storage complex required static and dynamic models of a size much bigger than conventionally utilized to describe hydrocarbon reservoirs.

Novel Petrel workflows have been generated to scale the details of the geological models for use in the dynamic simulator (CMG). Local grid refinement workflows have been established to reduce the run time of the dynamic simulations while increasing resolution around the injector locations. The impact of reservoir cooling during injection was estimated using a CMG version incorporating thermal effects.

Long-term safe storage of the CO_2 in the containment complex was demonstrated while using the TOUGHREACT geochemical modeling to estimate both, geochemical trapping as well as the absence of seal degrading reactions. [Ref 7.2]

11.3.2. Geophysics

The MMV Plan utilizes existing technology for surface time-lapse seismic and InSAR monitoring. Distributed Acoustic Sensing (DAS) will be deployed within each injector and this is a new technology for down-hole time-lapse seismic acquisition. A field trial of this technology at Radway 8-19 ([Ref 11.2] DAS-VSP report) demonstrates this technology works as expected. In the unexpected case that this new technology fails to perform as expected during the execution of the MMV Plan a contingency monitoring plan exists to acquire down-hole seismic data using existing proven technology based on a temporary deployment of conventional down-hole geophones. There are no significant risks to well integrity due to DAS as demonstrated by the cement bond quality achieved at Radway 8-19.

The MMV Plan also includes an opportunity to use Distributed Acoustic Sensing (DAS) technology to provide down-hole microseismic monitoring. The base case monitoring plan uses existing proven technology based on a conventional down-hole geophone array cemented in a deep observation well. This risk of DAS microseismic monitoring is mitigated by verifying the monitoring performance against this proven method.

11.3.3. Surveillance

Line-of-sight CO2 flux monitoring [Ref 11.3] is a new technology and one system will be deployed on each injection well pad. This technology is built on existing proven methods although its application to CO2 is novel. A field trial at Radway 8-18 planned to start summer 2011 to verify the performance of this technology is consistent with expectation. There are no alternative proven technologies capable of providing this monitoring function.

Well integrity monitoring using Distributed Temperature Sensing (DTS) and Distributed Acoustic Sensing (DAS) within each injector represents early applications of existing technologies. Technical feasibility studies indicate the expected monitoring performance is suitable for these applications. The risk of unexpected poor monitoring performance is mitigated by the use of additional methods based on existing proven technology to provide additional well integrity monitoring. These include cement bond logs, well integrity tests and down-hole pressure gauges with nearby deep observation wells.

Remote sensing techniques designed to detect any localized environmental changes associated with CO2 storage are new technologies with scope to provide an affordable wide-area monitoring capability. The risk that these techniques do not performance as expected is mitigated using proven ground-based sampling and analysis methods to verify the remote sensing results.

11.3.4. Tracers

11.3.4.1.Natural Basal Cambrian Sand Formation Fluid Tracers [Ref11.4]

A feasibility study has shown the Basal Cambrian Sand (BCS) formation fluid geochemistry as unique. This creates an opportunity to verify the absence of BCS formation brine in shallow groundwater samples to help demonstrate the security of CO2 storage within the BCS storage complex during the full lifecycle of the Quest Carbon Capture and Storage Project.

It is responsible to design a groundwater monitoring program to carefully verify that even small quantities of BCS brine have not entered the shallow groundwater. Clear evidence for the absence of impacts to groundwater quality is an essential part of continuing site operations and eventual site closure.

BCS brine tracers made up of naturally occurring geochemical constituent relationships that identify BCS brine have been assessed as feasible according to the following criteria:

- o Uniqueness
- o Detectability in % BCS brine.
- o Repeatability.
- o Current data coverage.

A tiered sampling & analysis protocol using a range of detection limits for BCS brine within groundwater has been developed to ensure reliable, cost-effective groundwater monitoring. Initial limits of detection will not be determined until prior to operational start up, and may be individual to each shallow groundwater monitoring well.

11.3.4.2.CO2 Injection Tracers [11.5]

Chemical tracers have been widely used for plume migration monitoring in CO_2 sequestration pilots. Typically, these applications have been one off deployment, i.e. tracer was injected at a certain location and was monitored for breakthrough at a nearby monitoring well. However, continuous or repeated tracer injection is necessary for tagging the CO_2 from a CCS project to avoid uncertainty about whether or not any CO_2 detected outside the storage complex may originate from CCS activities.

Perfluorocarbons (PFC) are the recommended option from the list of available tracers due to their high degree of partitioning into the CO_2 phase, high stability, limited interaction with the subsurface environment, availability, cost and ease of commercial deployment. Other tracers such as noble gases and CD_4 (Perdeuterated Methane) are currently being worked on and have been deployed in pilot studies, but these are not yet available for commercial deployment.

11.4. Wells

11.4.1. Drilling

There is no specific new technology applied in drilling the IW, DW or GW of the Quest project. However some existing technologies such as DAS and DTS will be installed behind the main casing. These two technologies target a new application compared to their standard use: the detection of leakage along the well, via temperature or acoustic signals.

11.4.2. Completions

There is no specific new technology applied in completing the IW, DW or GW of the Quest project.

11.5. HSE/SD

11.5.1. HSE/SD

The introduction of any new technology, the evolution of any processes or project infrastructure will involve a HSE/SD assessment. If deviation from standard operating protocol (SOP) is proposed, it is important to ensure that all HSE aspects are addressed in the best possible manner. HEMP reviews and following the ALARP process will be applied systematically to evaluate new technologies and changes that impact HSE.

HSE& SD will be given equal importance in evaluating and selection of technologies to ensure all hazards are identified and risks are reduced to ALARP. It shall also provide differentiation and even elimination in option selection of technologies with regards to HSE SD risks.

12. ASSET MANAGEMENT

12.1. Operations Philosophy

The Quest Operations Philosophy is detailed in a separate stand alone report entitled “Quest Operations and Maintenance Philosophy” [ref. 12.1]. This section of the SDP provides an overview of that report.

The Quest assets are essentially an addition to a number of existing facilities (the Hydrogen Manufacturing Units – HMUs) of the Shell Scotford Upgrader. As such the new facilities will be operated from Scotford, taking advantage of the existing infrastructure and organization.

Operations staff with the experience of the Scotford facilities has been brought on to the project at an early stage to ensure operational input to the design and construction of the facilities, and to implement Operational Readiness through the different phases of the project.

12.2. Asset Development & Operations Objectives

Expectations for the operation and maintenance (Operations) of the Quest facility include the following:

- A safe and healthy workplace. Compliance with legislation, company policies and procedures. No harm to people during operations is an achievable goal and Quest as part of the Scotford operation will strive to achieve this;
- Managing worker risk to a tolerable level or As Low As Reasonably Practicable (ALARP) including risks from transport, major accidents and occupational hazards;
- Industry leadership in care of the natural environment and resources;
- Economic maximization of production, cost effective operating performance, and positioning to capture opportunities and manage risks;
- Quest will earn the right to operate and grow, based on top quartile project and operational performance.
- To ensure that production and delivery of CO_2 to system transfer points is reliable and predictable and meets contractual obligations in the right quantity and quality at all times;

- Enhancement of Quest's position as a desired member of the northern Alberta community and energy industry.

The focus will be towards providing Great People, Great Execution and Great Processes. Operations will pursue a path of continuous optimization with respect to the effective utilization of manpower, automation, business processes and communication. Processes and techniques will be used to refine and improve overall quality and plant performance. It is anticipated that the key aspects of this strategy will include:

- A highly trained / multi-skilled workforce.
- A team approach to organization and work activities
- A stimulating, fun and rewarding work environment.

An organization that promotes measurements of leading indicators and pro-actively addresses issues prior to impact of business performance. This requires strict adherence to business processes and enablement of critical processes with effective IT deployment. Recognizing that it is not simple to keep it simple.

- Operate in the proactive and planned realm (vs. reactive). As such, the organisation will work to develop a culture of planning and analysis of operations activity and tasks;
- Safeguard the technical integrity of all assets owned and operated by providing fit for purpose technology, tools and techniques;
- Step out of the traditional oil and gas industry environment to explore and embrace other business and work execution mentality and approaches (i.e. manufacturing)
- Ensure quality is embedded in all activities, there will be a culture of continuous improvement and eliminating waste from all processes and activities.
- A working environment will be established, in which roles and responsibilities are clear, people are empowered to contribute, teamwork is fostered and recognized and people are encouraged to learn from mistakes. Maximum collaboration is expected between all parties (Shell and contractors) working towards common goals.

12.3. Operations and Maintenance

12.3.1. Asset Reference Planning

The Asset Reference Plan (ARP) for Quest covers the different asset parts of the Quest opportunity:

- The Capture interface with the existing Scotford production facilities, essentially the process units – HMUs, Utilities systems (steam, process water, cooling water, power, nitrogen, air)
- The new Capture facilities: absorbers, regenerator, compressor and pipe-line interface
- The new 12"pipeline from the capture facilities to the storage site
- The new injection and observation wells at the storage site

The ARP objectives are to define the boundaries of the asset operation (operation and process safety, equipment integrity) and business utilization to match the premises of the Quest business case (safety, production costs and economics).

Addressing the different parts of Quest:

- The new Capture section and its interface with the Scotford facilities, as they are located within the Scotford Upgrader site plan, will be subject to the existing Operation Excellence standards of the Scotford operation. In particular the operating procedures and definition of the operating envelope will come as an addition to the existing operation documentation of the Production Unit 1 (PU1) of the Scotford Upgrader, in line with the Operation Philosophy of Quest.
  Furthermore the production scheduling (the actual CO2 captured and removed from the Upgrader emissions) will be deeply integrated with the existing hydrocarbon production model following the production flow:

  > Albian bitumen => Hydrogen demand from the RHC => HMU loading => CO2 production => CO2 captured => CO2 transported => CO2 sequestered

  This will define the business utilization of the Quest assets, including the planned maintenance and inspection turnarounds of the Scotford site.
- The new 12"pipeline will be operated and maintained according to the Shell and Alberta standards, that include a leak detection system and the setting-up of an on-stream inspection system (instrumented pigs). The base loading of the

pipeline follows the same production model as the one governing the Capture part, however the pipeline has been sized to allow additional commercial capacity.

- The injection and observation wells are subject to the Reservoir and Well surveillance plan described below in *Well and Reservoir Management*.

12.3.2. Integrated Activity Planning

Quest is a deeply integrated project from both the technical (surface and subsurface) and organizational angles (Operation, Project, Business, Regulatory , External Affairs). As a consequence an advanced interface management plan has been set-up (detailed in *Interface Management* below).

The integrated management of Quest is supported by the integrated activity planning detailed in the integrated schedule that shows the project key milestones and the related planning, execution and deliverables for the different organizational components of Quest.

The integrated planning includes the key internal (such as the Scotford Upgrader Turnarounds) and external events (such as the regulatory approval and public hearings).

The progress to the milestones is checked through the Quest assurance reviews and approved by the Quest Decision Review Board (DRB).

12.3.3. Well and Reservoir Management

The Well and Reservoir Management process addresses the area between reservoir and well management with the goal of reducing uncertainty, proactively recognizing problems and exploiting opportunities to meet project and business objectives.

For the QUEST Project, WRM is a subset of a broader MMV (Measurement, Monitoring and Verification) plan. MMV is to assure all the stakeholders (Internal and External) on the effectiveness of CCS and demonstrate realisation of project deliverables on

Injectivity, Capacity and Containment. More details are available in Section 10. Measurement, Monitoring and Verification (MMV).

APPENDIX 1. THE WRM RESPONSIBILITIES ARE SPREAD OVER SEVERAL TEAMS AS DESCRIBED IN APPENDIX 7 (INTEGRATED CONTROL SYSTEM SCHEMATIC

Responsibilities and accountabilities for MMV). In particular:

- The wells will be remotely monitored and controlled from Scotford Control Room, and all data will be also available in real time in Calgary
- Scotford Operations will be accountable for:
  - Performing the day-to-day operations and monitoring activities
  - Executing the routine well and wellhead maintenance
  - Responding to the safety critical and operational alarms
- SCAN Surveillance Team, Quest Venture Subsurface Team and Quest Environmental Team will be accountable for:
  - Organising the daily and monthly, quarterly and annual surveillance reviews
  - Coordinating the planned well interventions
  - Responding to the non-safety critical in-well MMV alarms
  - Performing the geosphere, hydrosphere biosphere and atmosphere MMV activities, requiring specific subsurface skills
- The wells will be operated by flowrate setpoints to spread injection over the different wells, with built-in automated overrides
  - The flowrate will be measured at each wellsite and at the pipeline inlet
  - If the pipeline pressure decreases below 8.5 MPa, the well chokes will start to close to maintain the minimum pipeline pressure
  - If the wellhead pressure increases above the maximum allowable injection pressure (10 to 13.9 MPa depending on wellhead temperature), the well chokes will start to close to decrease wellhead injection pressure
  - If the wellhead pressure drops below 1 MPa (proposed value) the SC-SSSV will be automatically closed
  - If the water content goes above specifications (proposed threshold is 8ppm), the compressor will automatically go in recycle mode.
  - If the Hydrogen content goes above specifications (proposed threshold is 2.5%), the compressor will automatically go in recycle mode.
- The injection policy is based on a 1-spare well capacity so that sufficient injection can be ensured even if one well is shut-in (e.g. for workover) and is constrained by a maximum downhole injection pressure of 28 MPa.

12.3.4. Data Management

Data management including data gathering, data transmission, data retrieval for interpretation, data archiving are the cornerstone for effective wells operation, surveillance and control and need to have flexibility for remote operation. The conceptual layout of data architecture proposed for the Quest project is provided in *Figure 12-1 Proposed SCADA Data Flow for the Quest Project* and *Figure 12-2 Proposed Quest Project Data Flow to Shell Centre in Calgary* below.

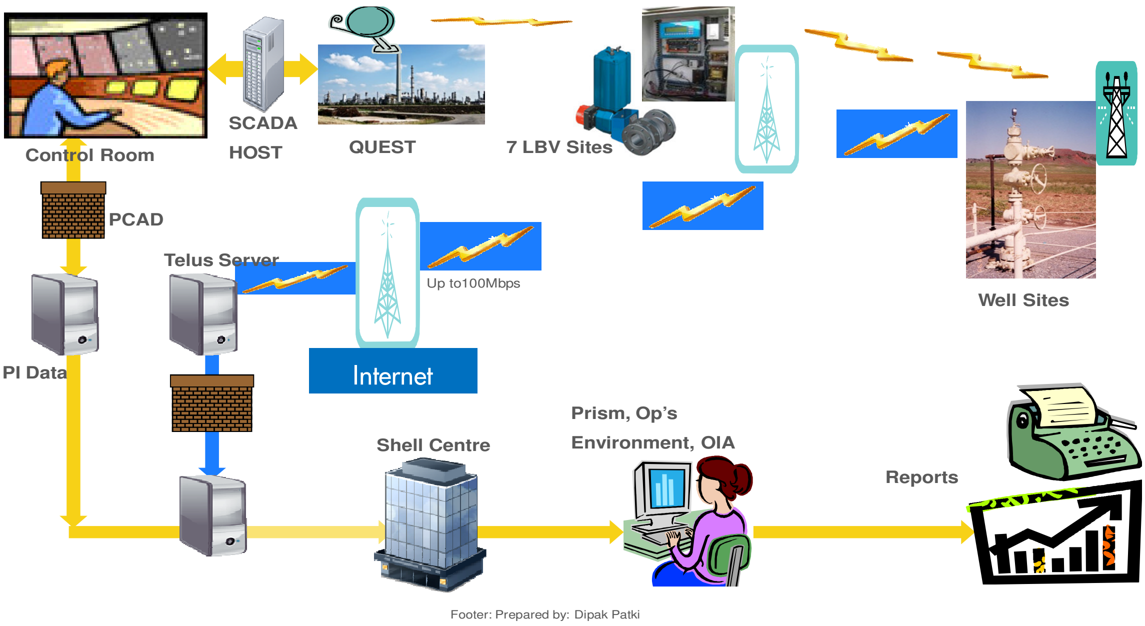


Figure 12-1 Proposed SCADA Data Flow for the Quest Project

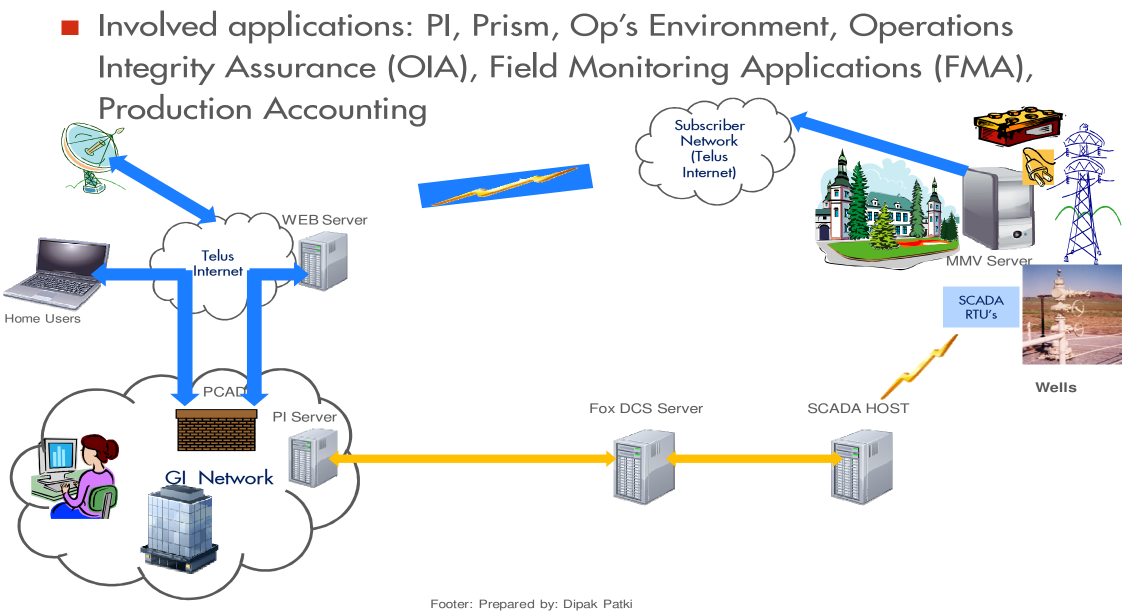


Figure 12-2 Proposed Quest Project Data Flow to Shell Centre in Calgary. APPENDIX 10 describes the data management plan for MMV.

12.3.5. Maintenance and Technical Integrity Management

The maintenance and technical integrity management of the Quest assets covers the three parts of Quest: capture, pipeline, and wells.

The maintenance and integrity of the reservoir and wells is described in the *Measurement, Monitoring and Verification (MMV)* and will be managed by the Calgary surveillance organization.

The Capture and pipeline parts are managed by Scotford during the Operation Development & Implementation phase (maintenance and integrity planning, equipment quality control and acceptance), then during the normal operation phase as part of the site asset management plan.

The Operation Implementation team includes a maintenance and engineering department in charge of:

- Setting-up-up the Maintenance, Turn Around (TA) and Asset Integrity technical and costs targets for the Quest facilities in line with the Asset Integrity and Process Safety Management standards (AIPSM) and Scotford performance targets (e.g. reliability targets and alignment on TA frequency)
- Setting-up and managing the Quest Maintenance and Engineering team, hiring plan and competence development for the team members. Jointly with the Quest project Engineering and CSU teams, it identifies the vendor support requirement for Commissioning and Start-Up
- Jointly with the Quest Engineering team managing the technical risks down to the As Low As Reasonably Practicable (ALARP) level
- Developing the Statement of Fitness prior to the Commissioning of the Quest Assets
- Setting-up the Quest maintenance, TA and engineering budget as part of the OPEX fixed costs
- Setting the Quality Management requirements (e.g. documentation, FATs and SATs) as part of the input to the Quest project and following-up on implementation during the Detailed Engineering and Construction phases
- Interfacing with the Quest CSU manager, HSSE Coordinator to see that the Engineering, Maintenance and TA plans are aligned with the Operating procedures for the different modes of operation (s/up, steady state, s/down)

12.4. Operational Controls and Alarms

Controls and alarms will be part of the system to ensure it operates within the safe operating envelope, as defined in section 7. The schematic given in APPENDIX 8 shows the integrated system controls and alarms. Table 12-1 presents the list of alarms and controls the system will be operated with.

Measurement	Measurement point	Minimum Operating value	Maximum Operating value	Alarms*	Control
Pipeline Pressure	Pipeline inlet	8.5 MPa	13.9 MPa	High: 14* MPa	High: Spillback of compressor starts in order to reduce pipeline pressure below maximum setpoint. ***This alarm overrides any other control as it is safety critical.***
	Pipeline outlet (upstream of well choke)	8.5 MPa	12.9 MPa	Low level 1: 8.5* MPa Low level 2: 8* MPa	Level 1: well choke start closing to reduce injection rate. Level 2: in case well chokes fail to maintain pipeline pressure above minimum, the well ESD valve will close at the well pad where the low pressure alarm goes off.
	LBVs	8.5 MPa	13.9 MPa	7* MPa	In case the pipeline pressure drops below normal minimum pressure (even with the ESD valves closed), the LBVs will close automatically (pipeline leak detection). ***This alarm overrides any other control as it is safety critical.***
Pipeline Inlet Temperature	Pipeline inlet	43 degC	60 degC	Level 1: 49* degC Level 2: 60* degC	Level 1: alarm in Scotford control room to investigate abnormal performance of the cooling system. Level 2: shutdown to protect pipeline.
Pipeline flowrate	Pipeline inlet	0 Mtpa	1.2 Mtpa	No alarm required	Pipeline flowrate is controlled by the wells flowrate operator setpoints.
Wellhead Pressure	Downstream of well choke	3.5 MPa	12 MPa	Low alarm: 1* MPa High alarm: 10*-12* MPa (will depend on wellhead temperature, to ensure bottomhole pressure does not exceed 28 MPa)	Low alarm: Alarm in Scotford and closing of the SC-SSSV (blowout detection). High alarm: Well choke will automatically start to close until wellhead pressure is below maximum allowable value. ***This alarm overrides any other control as it is safety critical.***

Downhole Well Pressure	Bottom of completion	20 MPa	28 MPa	27* MPa	Alarm in Scotford control room to investigate high well pressure (consistency with wellhead pressure).
Wellhead temperature	Downstream of well choke	-10 degC	26 degC	No alarm required	Wellhead temperature controlled by choke and CO2 pipeline outlet temperature.
Downhole temperature	Bottom of completion	15 degC	60 degC	No alarm required	Downhole temperature controlled by well flowrate and wellhead temperature.
Well flowrate	Upstream of well choke	0 Mtpa	0.6 Mtpa	No alarm required	The flowrate is an operator setpoint. The choke will automatically open or close to meet the set point, within the allowable pressure envelope.
H2 content	Pipeline inlet	2.5%	0.67% (normal)	Level 1: 1.5%* Level 2: 2.5%*	Level 1: alarm in Scotford control room to investigate abnormal CO2 purity, well chokes are manually adjusted to raise pipeline pressure to 9* MPa to maintain single phase flow. Level 2: compressor enters automatically recycling mode to protect pipeline and wells, and ESD closes after a delay.
Water content	TEG unit outlet	4 lbs/MMscf	6 lbs/MMscf	Level 1: 7* lbs/MMscf Level 2: 8* lbs/MMscf	Level 1: alarm in Scotford control room to investigate abnormal water content. Level 2: compressor enters automatically recycling mode to protect pipeline and wells, and ESD closes after a delay.

** Note: exact value will be confirmed during the next phase.*

Table 12-1: Operational Controls and Alarms

More details on operating controls and alarms are available in the MMV Plan and in APPENDIX 10.

12.5.Operations Functional Requirements

A significant part of the Operations Philosophy details the specific Operational Functional requirements in a number of areas as follows. For the detail the reader is directed to the Operations Readiness document.

These are addressed in ORA document

- Integrated Production System
- Product Quality
- Control and Automation
- Production Measurement and Surveillance
- Shut-down & Safeguarding
- Operability and Maintainability
- Logistics
- Flow Assurance
- Special Operations
- Wells
- Process Facilities
- Infield and Export Pipeline system
- Late field life requirements
- Abandonment and Mothballing / Suspension
- Supporting Assets

12.6.HSE

The Quest approach to HSE is described in *HSSE AND SD* of this FDP.

During the Operations Phase, active, systematic and progressive, Safety, Health and Environment programs will be implemented, to ensure compliance with the law and to achieve continuous performance improvement. These programs will encompass all employee and contractor activities associated with the project and will be developed to achieve the Shell Group HSE & SD principles.

Managing Health, Safety and Environment effectively is top priority to the Shell Group. For this purpose an HSE Management System (HSE MS) has been developed which the Quest project will follow.

Consistent with HSE requirements, an Operational HSE Case will be developed as a project deliverable to operations. This document will be separate from, and supplement the project design HSE Case. It will consider current practices and Shell Canada Energy requirements. The Scotford Operations Manager will approve the HSE Case.

12.7. Organization

The Operation organization is set-up to match the phased development of the project:

- Operation development & planning during the front-end development phase of the project
- Operation implementation
- Normal operation according to the asset operating philosophy

12.7.1. Operation development & planning during the front-end development phase of the project

During this phase that starts with the early development of the project and ends with the completion of the basic engineering and investment decision (FID), the operation team is in charge of defining the operability and maintainability requirements for the project deliverables. The same team checks that these requirements have been implemented during the engineering reviews.

In parallel, the integration with the site facilities is addressed, both technically with the identification of the system integration points and organizationally with the setting-up of the Operation team for the next phase.

12.7.2. Operation implementation

This phase succeeds the development & planning phase. It starts with the investment decision and ends with the start-up of the new facilities. The Operation team, now augmented with the operation discipline specialists and leads, is in charge of supporting the detailed engineering and construction of the new facilities. The handover systems are defined so the acceptance of the new assets takes place leading to the commissioning and start-up of the facilities.

12.7.3. Normal operation

This phase follows the start-up of the facilities that are now operated to meet the targets defined by the production plan for the rest of the asset life.

The Quest operation function through the project phases is summarized by the *Figure 12-3 Operations Model in the Quest Project*

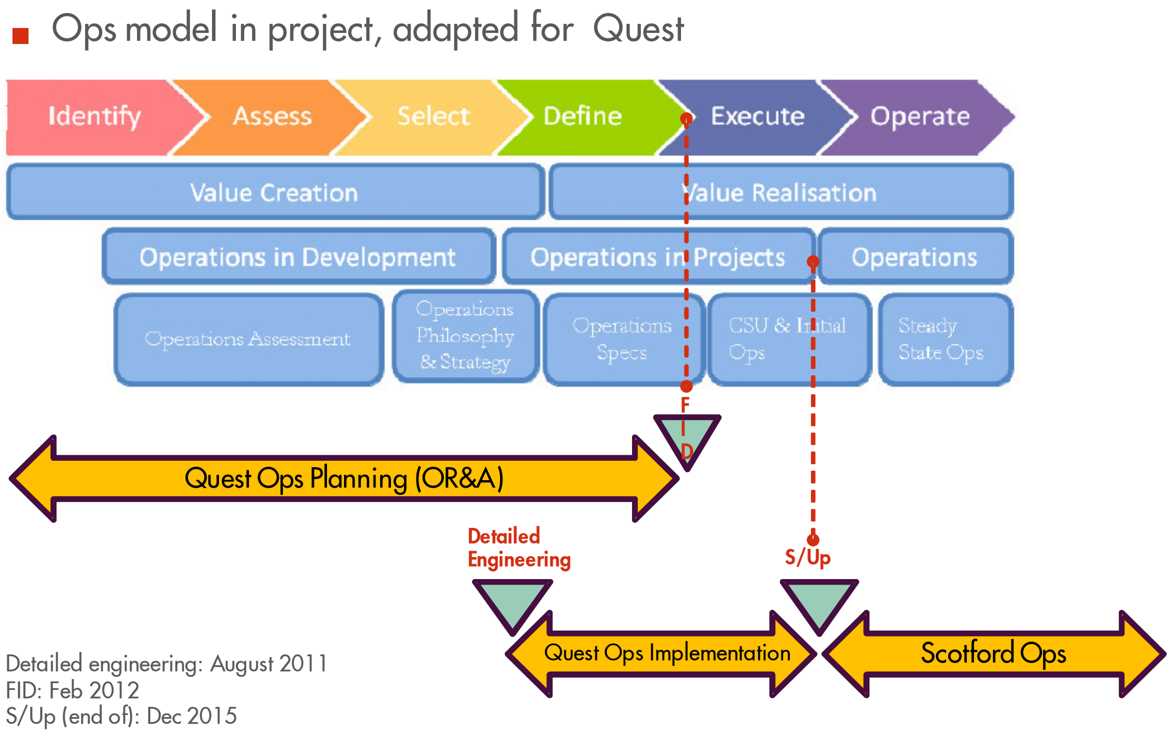


Figure 12-3 Operations Model in the Quest Project

13. PROJECT EXECUTION STRATEGY

Please see the Quest CCS Project Execution Plan Rev04 (07-0-AA-5760-0001) [Ref13.1] for more information.

13.1. Project Governance and Leadership

The Quest CCS Project follows the established governance structure for the AOSP JV:

- **Executive Committee (Excom: Budgets > $15 million)**
- **Operating Committee (Opscom: AFE's and contracts < $15 million)**

13.1.1. Quest Venture Decision Review Board (vDRB)

As prescribed in the ORM, a Decision Executive (DE) is in place supported by a Decision Review Board (DRB) that takes all key decisions to progress the Quest CCS opportunity.

The composition of the DRB is as follows:

Name	Role	DRB Role
John Abbott	EVP Heavy Oil	Decision Executive
Tim Bertels	Unconventional & EOR SIEP	DRB Member
Andrew Ritchie	SR CX Manager Heavy Oil	DRB Member
Robert Patterson	VP Upstream Projects Americas	DRB Member
Carmelina Riccio	HO Finance Manager	DRB Member
Peter St.George	GM Scotford Upgrader	DRB Member
Bonnie Vogeli	Sr. Legal counsel Oil sands	DRB Member
John Broadhurst	HO Development Manager	DRB Member
Tony Farmers	CP Manager Projects Americas	DRB Member
Sam Whitney	Technical Services Manager	DRB Member
Ian Silk	Quest Business Opportunity Manager	

13.1.2. The Project Delivery Assurance Board (PDAB)

The focus of the Execute phase is to deliver the asset to the asset owner, in this instance the Scotford Upgrader, ready for start-up and operation.

As such at FID the major reviews and milestones on the project outlined in *Table 13-1 Execution Phase Preliminary Review Schedule* will change focus from delivery of an opportunity to implementing and construction and it is recognised that the membership of the DRB should change accordingly to reflect the change in focus and become the PDAB

(Project Delivery Assurance Board). The exact composition of the PDAB will be determined by the DE.

Table 13-1 Execution Phase Preliminary Review Schedule

	2012	2013	2014	2015
PERT's	1	1	1	
Post Engineering Knowledge Capture		1		
Flow Assurance & WRM Review		1		
VAR 5A (mid-construction)		1		
Pre-Start-up Audit			1	2
Post-Construction Knowledge Capture				1
VAR 5b (Post-Start-Up)				1
Total Review Weeks	1	4	2	4
Review Norm (per week)				

13.1.3. Overall Project Management

The DE and DRB meet regularly to review and assess the required decisions as identified in the Decision Based Road Map. The Decision Based Road Map is the deal sheet of the Venture team, led by the Business Opportunity Manager (BOM). The Decision Based Road Map is a key document for the venture and can only be updated with approval from the DE/DRB. It describes the key decisions that must be taken to progress this opportunity and its associated risks. The line of sight (LOS) to FID is through the DE (EVP Heavy Oil) and the Quest BOM.

The BOM is supported by his venture team, Heavy Oil Operations, and a technical team from the Projects and Technology (P&T) division in Shell. The P&T team is led by the Project Manager (Anita Spence).

The Project Manager is responsible for the technical definition and execution of the Quest CCS surface facilities, pipeline and well hook-ups. Past DG4, when the subsurface definition work is finished, the PM's responsibilities may include the injection and monitoring wells delivery.

13.2. Project Services

13.2.1. Cost Estimating

The Project Control Team has been heavily involved with the contractors' estimation departments, in defining, guiding, and reviewing the basis of the estimate during DEFINE. The Project Control Team has also participated with the Heavy Oil/P&T Project Control Group in preparing Check Estimates and estimates of other costs outside the Contractors Scopes like Owners' costs, etc.

At the end of DEFINE, a Type III estimate has been prepared. This estimate has been structured in accordance with the Project WBS.

13.2.2. Budgeting and Cost Control

Cost control during any phase of a project comprises the setting up of the cost procedures and systems and the monitoring and the reporting of the actual project expenditure and commitments against the approved project budget. The early identification and registration of deviations together with the following of trends enables project management to control the project. Cost control for Quest will be accomplished by implementing the processes and tools described in Section 15.3 of the Project Execution Plan rev04.

13.2.3. Planning & Scheduling

An Integrated Master Schedule (Level 2) and underlying EXECUTE phase schedule (Level 3) have been developed for the Quest project. The schedules have been developed using the Shell approved planning software, Primavera P6. Key milestones and interfaces between project sub-components are included. The schedule is logically linked such that the critical path and near-critical activities are visible and understood. Schedule risk analysis has been performed using the Shell approved schedule risk analysis software, Pertmaster, and the resulting schedule contingency has been reflected such that the schedule yields a P50 sustained operation milestone.

Table 13-2 Key Milestone Dates For the Quest Project

Milestone	Timing
FEED Phase Complete	Q3 2011
EASR4/VAR4	Q3 2011
DG4	Q4 2011
ERCB Regulatory Hearing	Q4 2011
ERCb Regulatory Approval	Q1 2012
FID	Q1 2012
Substantial Det Eng Complete	Q1 2013
Compressor recieved	Q4 2013
Capture Fac. & HMU 3 Mech. Complete	Q4 2014
HMU 1 & 2 Mech. Complete	Q2 2015
First Injection	January 2015
Quest facility Start-Up	Q2 2015
Sustained Operation Achieved	Q4 2015
HMU 2 turn around	Spring 2013
HMU 3 turn around	Spring 2014
HMU 1 turn around	Spring 2015

Contracting & Procurement

Contracting & Procurement (CP) activities on Quest are governed by the global CP Category Management and Contracting Process; https://a100.sharing.shell.com/sites/ac34798b2aba456cb76969daa25a348a/Chevron%20Pages/Strategy%20Selection.aspx#Title

13.2.3.1. CO2 Capture

An overview of the current contracting quilt for the Quest Project (CO2 capture element) is shown below;

	Detailed Engineering & Procurement	Construction services: Amine Regeneration Compression	Construction services: HMU 1&2	Construction services: HMU 3, Piperack, Utilities and U/G pipeline	Construction services: SPG Tie-ins	Construction Management	Commissioning & Start Up
Percent of Budget		50%	15%	30%	5%		
	FLUOR	Site Preparation and U/G - Unit Rate-Bid			n/a	FLUOR	SITE OPERATIONS
		Piling - Unit Rate-Bid			n/a		
		Civil/Concrete Foundations - Unit Rate-Bid			n/a		
		Module Fabrication - Lumpsum & Unit rate& T&M-Bid			n/a		
		Heavy Haul and Lifting - T&M- Shell existing agreement			n/a		
		Module Installation- T&M			n/a		
		Structural Steel-T&M			SCOTFORD PROJECT GROUP		
		Piping & Mechanical Equipment Installation-T&M					
		Electrical & Instrumentation-T&M					
		Insulation - Unit Rate-Shell existing agreement or bid					
		Services and Indirects - Shell Existing agreements or bid					

Yellow: Denotes single discipline contract across all areas
Red: Multi-discipline contract: Fluor DFL
Green: Green Field
Brown: Brown Field

Figure 13-1 Current Contracting Quilt for the CO2 Capture

Shell awarded an Engineering, Procurement, Construction and Construction Management (EPCC) contract to Fluor Canada Ltd. (Fluor) in March 2010. Within this agreement, Fluor is responsible for Project management, quality assurance and control plans, engineering, procurement, contracting, project controls, construction, construction management services and information management services, as applicable.

For reasons of cost effectiveness, module fabrication and assembly will be executed at a Module Yard facility located in the Alberta High Load Corridor (HLC). Heavy Oil Contracts Board supported this strategy in Nov 2010, including the requirement to tender the work to Edmonton based fabrication yards. Enterprise Category & supply (ECS) function have been fully involved in this process to date, including market reviews. Construction services are planned to be awarded to Fluor Direct Force Labour to perform the on-site construction work including Module installation, structural steel, Piping & Mechanical equipment installation and Electrical and Instrumentation (via existing EPCCM contract).

Heavy Oil Contracts Board approved in Feb 2011 to award Scotford on-site construction services (Module Installation, Structural Steel, Piping & Mechanical and Electrical and

Instrumentation) to Fluor and also subcontracting of the Construction scope to Fluor's affiliate Fluor Constructors.

Considerable procurement activities have already been undertaken by Fluor for bidding of long lead items. Extensive use of EFA's will also be made for key procurement items in areas such as Mechanical Equipment, Piping Bulks/Specialities, Electrical Equipment, Control Systems & Instrumentation.

13.2.3.2. Pipeline

An overview of the current contracting quilt for the Quest Project (pipeline element) is shown below;

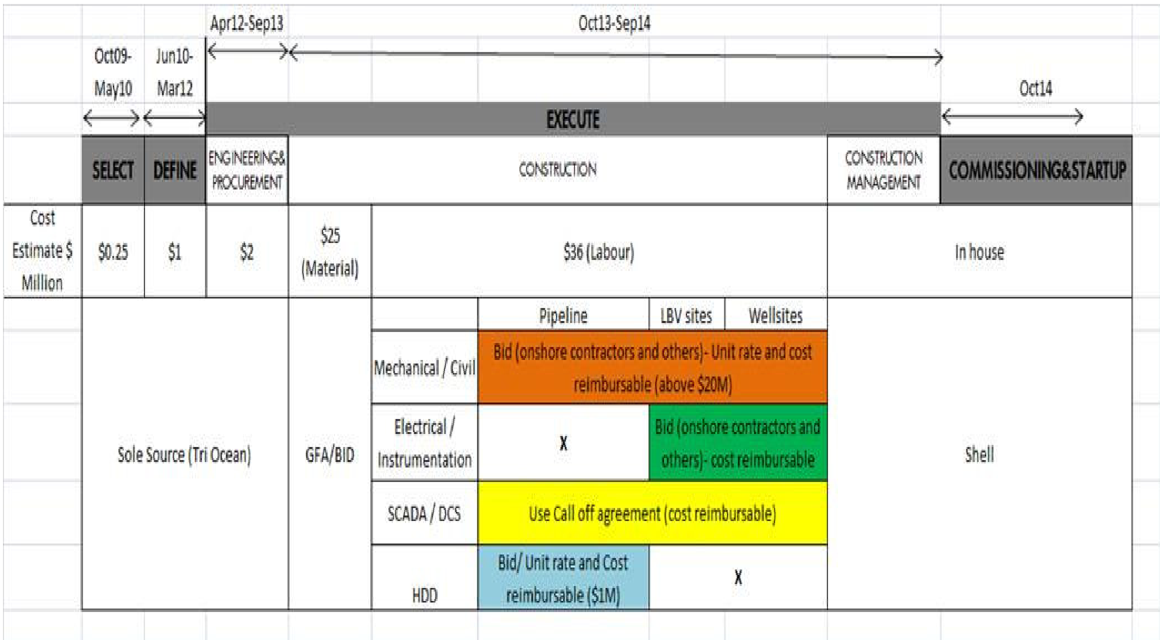


Figure 13-2 Current Contracting Quilt for the Quest Pipeline

The Define phase and Engineering and Procurement was awarded on a single source basis to Tri Ocean Engineering Ltd. (Tri Ocean) to ensure continuity with Tri Ocean and build on relationships already established with other CCS projects . For Construction (Mechanical/Civil and E&I work will be competitively bidded between onshore gas mechanical contractors with invites to additional contractors that have specific expertise and experience for large size pipeline projects. For SCADA, Shell existing call-off agreements will be utilised to ensure compliance with existing standards. HDD will be subject to competitive bidding. Construction & Project Management will remain in-house (Shell).

CP Team currently comprises a Senior Contracts Engineer and a Procurement Manager reporting to the CP Lead. The role includes specific oversight of Fluor CP activities at their offices in Sundance and co-ordination with Enterprise Category & Supply (ECS), plus obtaining of relevant approvals as required (Contracts Boards etc). Local Content requirements will also be closely monitored.

Further details on Contracting & Procurement activities on Quest are contained in Document 07-0-AA-5798-0002 Project Execution Plan

13.2.4. Logistics

The logistics for wellsite construction (e.g. rig moves, rig set-up, material movement, etc.) will be subsumed within the base business of the existing Wells organization in Upstream Americas. Existing supply agreements – for wellsite services or for equipment and materials – will be leveraged wherever it makes sense to do so. The benefit of doing this is two-fold: from a HSSE perspective existing suppliers are pre-qualified and familiar with Shell's requirements (e.g. the HSSE Control Framework and the Life Saving Rules, particularly those relating to the transportation of people or equipment); and from a commercial perspective the use of these agreements typically results in the best value for Shell.   More details on these topics as they relate to each of the Capture, Pipeline, and Subsurface components of the Quest CCS project can be found in the *Logistics, Waste Management & Infrastructure Execution Plan*.

13.3. Organisational Plan

Management of the Quest CCS Project is the responsibility of Shell Canada Limited-Oil Sands (AOSP) on behalf of the Joint Venture partners.

The Business Opportunity Manager (BOM) has the single point accountability for managing the Quest CCS opportunity from pre-scouting through to completion of DEFINE phase. Thereafter, the BOM remains responsible for managing the opportunity until Handover.

From DG4 onwards, the Projects and Technology (P&T) division is single point responsible for delivering projects on behalf of the business (in this case Heavy Oil). The Quest CCS project adheres to the processes and procedures that are applied in P&T for project delivery. For a high level overview of the proposed Quest Leadership Team for the Execute Phase see *Figure 13-3 Quest Project Leadership Team for Execute (Level 0, 1 & 2 only)*

13.3.1. The Project Manager

The Project Manager Quest from the Projects and Technology business group has the single point accountability for managing the Quest CCS Project from the EXECUTE phase until 'Ready for Start-up' (RFSU) and hand over to Upgrader Operations.

P&T in Calgary will begin staffing the Quest CCS Project team to reflect the transfer from the DEFINE phase into the EXECUTE phase for the Quest CCS Project (i.e. Capture, Pipeline and well hook-ups) at the end of 2011. The wells delivery part of the project may become the responsibility of the Project Manager after FID, this is currently being reviewed.

13.3.2. Subsurface

During EXECUTE the Quest subsurface team has been sized and staffed to deliver injector wells 2 and 3 in 2012 and the baseline MMV plan. Expectation is that these wells will likely be sufficient for start-up in 2015 and a final decision will be made in the second half of 2012 as to the number of wells required for start-up, the numbers and locations of deep MMV and the associated length of the pipeline. This SDP will be updated accordingly. Therefore expectations are that further development of the Quest storage facility is unlikely during the early years of operation and the focus will be on well operations and executing the MMV plan. The OPERATE organisation envisaged therefore comprises 3 principle elements:

- Ops: Scotford Upgrader operations accountable for the day to day safe operations of the storage facility
- Monitoring: WRM (surveillance) accountable for the day to day delivery of the non-safety critical part of the MMV plan
- Support: geology, petrophysics and geophysics support, provided from HO In-situ Development for additional development activity (if any) or elements of the MMV programme outside of the core WRM experience set such as 3D seismic

Note that this arrangement is effectively in place already for Scotford for the water disposal well, and the WRM/ Development collaboration is mature and effective for the HO In-situ assets. Detailed RACI charts (APPENDIX 5) have been drafted to cover the execution of the geosphere elements of the MMV plan, and the modelling requirements for the hydrosphere elements of the MMV plan that detail the exact accountabilities between these 3 groups.

Should more than 3 wells be envisaged before start-up, the EXECUTE Quest subsurface team will be reviewed to ensure that sufficiently broad subsurface and well engineering resources are obtained or retained to deliver the additional development work ahead of setting up the above described OPERATE organisation, again well ahead of start-up.

13.3.2.1. Well Engineering

The well engineering group has worked closely with the Quest Venture team on the delivery of the three existing wells:

- SCL Redwater 11-32 (Scotford)
- SCL Redwater 3-4 (Redwater)
- SCL Radway 8-19

The well engineering group is already engaged with the Quest Venture team on delivering the execute phase of the Quest project and the well delivery process has already begun for development wells SCL Radway 7-11 and SCL Thorhild 5-35 as per the subsurface timeline laid out in APPENDIX 4. It is anticipated that all future wells will follow the same Well Delivery Process.

The well engineering group has also been engaged on the strategy behind the water well drilling and were used to cover HSSE aspects of the water wells drilled on the Radway 8-19 well pad although this was drilled as a turnkey operation.

13.3.2.2. Completions & Well Interventions (CWI)

The Completions and Well Interventions team have also been closely involved in terms of both completion, perforation and testing of the existing wells:

- SCL Redwater 11-32 (Scotford)
- SCL Redwater 3-4 (Redwater)
- SCL Radway 8-19

The CWI group is already engaged with the Quest Venture team on delivering the execute phase of the Quest project and the well delivery process has already begun for development wells SCL Radway 7-11 and SCL Thorhild 5-35 as per the subsurface timeline laid out in APPENDIX 4. It is anticipated that all future wells will follow the same Well Delivery Process.

The CWI group will also have an important role to play during the Start-Up (well conditioning) and Operate Phase of the project in terms of planned and unplanned well interventions (See APPENDIX 5).

13.3.2.3. Geophysical Operations

Geophysical Operations have been working in close co-operation with the Quest Venture to date to deliver the following items:

- Quest 3D seismic survey
- Reprocessing of the 2D vintage seismic lines
- Acquisition of the VSP
- A field trial and interpretation of the DAS seismic new technology
- Contracting for the InSAR data acquisition
- Contracting and field installation for the LOSCO2 trials

A similar close working relationship will be required between the subsurface team and the geophysical operations group during the Execute and Operations phases of the project.

13.4. Engineering

The following entities / contractors are currently involved in the venture:

- Capture Facilities Process Licensor - Shell Global Solutions
- Capture Facilities – Fluor Canada Ltd.
- Capture Tie-Ins – Scotford Projects Group
- Pipeline and Wellsite Facilities – Tri-Ocean
- Preparation of HMU PDP - Uhde
- Wells – Shell Exploration and Production
- Operations – Scotford Ops Integration Team
- PSA vendors (Air Products for HMU 1&2, UOP for HMU 3 PSA unit modifications)

The Capture EXECUTE phase engineering will be completed by Fluor based out of their Calgary office with support from their New Delhi office.

To accomplish the EXECUTE scope of work, Fluor will utilize the following strategies and resources:

- An Engineering strategy for straight through engineering with work completed sequentially and building on foundations of reviewed information will be used. This approach reduces recycle and is consistent with project objectives of cost efficiency. Data sheet release will be prioritized to support acquisition of selected vendor data required of layout.
- A design strategy to modularize approximately 70% of the plot area will be used. The degree of modularization will be maximized to include Electrical and Instrumentation components; this approach is called "3rd Generation Modularization^{SM}".
- EXECUTE phase deliverables are drafted in the PCAP. This has been included in the Detailed Engineering Phase Work Authorization with Fluor and appropriate supporting documents have been listed in the Fluor Scope of Services portion of the work authorization (for example detailed calculations, RFP packages, module drawings etc)

The Pipeline EXECUTE phase engineering will be completed by Tri Ocean, directed by a dedicated Shell Quest Pipeline Project Engineer. Subsurface engineering will continue to be supported from within the Shell E&P organization.

Figure 13-3 Quest Project Leadership Team for Execute (Level 0, 1 & 2 only)

- **Quest Project Manager**
  - **Engineering Manager**
    - Process Engineer
    - Disc Engineering (8, some P/T)
    - IM
  - **Project Engineering Manager**
    - Proj Eng Capture
    - Proj Eng U&O
    - Proj Eng Pipeline
  - **Construction Manager**
    - Mod yard Super
    - Scotford Super
    - Pipeline Super
    - LEAN Const Manager
    - Well Delivery Interface (P/T)
  - **Integration Co-ordinator**
  - **Project Services Team Lead**
    - Cost Lead
    - Planning Lead
    - QS
    - Reporting Lead
    - Risk Co-ordinator (P/T)
    - MOC Co-ordinator (P/T)
  - **CP Team Lead**
    - Contracts Lead
    - Procurement Lead
    - Contract Admin
  - **HSE Manager**
    - Tech Safety Eng
    - Environmental Eng
    - Construction HSE
  - **Quality Manager (P/T)**
    - QA Engineer (5)
  - **Business Opportunity Manager**
    - Commercial Lead
    - Regulatory Lead
    - Economist (P/T)
    - CX Rep (P/T)
    - Community Liaison (P/T)
    - Government Relations (P/T)
  - **Subsurface Team Lead**
    - Geologist
    - Reservoir Engineer
    - Production Technologist
    - Hydrogeologist/ Geochemist
    - Petrophysicist (P/T)
    - Well Design Interface (P/T)
  - **Operations Readiness Manager**
    - CSU Manager
    - Ops Co-ordinator
    - Engineering & Maintenance Manager
    - Maintenance Co-ordinator
    - Ops HSE Co-ordinator
  - **Project Finance Manager**
    - Lead Project Accountant
    - Project Accountant

Reporting Relationships Key:

P&T resources reporting to Project Manager

Collocated with project, dotted line to Project Manager, hard line to HO Development

Collocated with project, dotted line to Project Manager, hard line to HO Ops

Supports Project Manager, reporting to other HO Functions

Supports Project Manager, reporting to other UA Businesses

Supports Project Manager, reporting to Global Functions

Collocated with project, dotted line to Project Manager, hard line to Global Functions

13.5. Supply Chain Management

The Quest Project includes three main components: the Pipeline, the Capture Facility and the Subsurface activity. Quest Project Procurement manages the procurement activities for the Pipeline and the Capture Facility. The UA Wells CP team manages the subsurface CP activity for Quest.

The purpose of Quest Project Procurement is to work with the Project Management, Engineering, and Construction teams to provide all equipment and materials to the Quest Project at best value and by the Required At Site (RAS) date. Such provisions must:

- Represent best value to the project,
- Comply with all legal, commercial and technical conditions of purchase,
- Conform to the strategic project objectives,
- Be within budget,
- Be delivered on time to meet the construction schedules; and
- Be aligned with Shell global ECS strategies.

The project procurement strategy is based on Shell's supply chain systems and procedures and has four main themes:

- leveraging strategic supply agreements
- leveraging Low Cost Country Sourcing (Sustainable Sourcing)
- competitive bidding in the absence of strategic supply agreements (alignment with ECS as to bidders)
- maximise Canadian content

The first three themes are fully aligned with Shell's ECS group and seek to harness Shell's global procurement spending power and reach, ECS sourcing strategies and obtain best value for the project. The latter theme is reflective of the substantial Canadian and Alberta governments' funding of the project and the need to comply with governmental and public expectations. Although obtaining a percentage of local content is not a contractual obligation, it is a prudent course of action in order to maintain and manage Shell's reputation. It must be noted that the latter theme is not necessarily mutually exclusive with the former and on the contrary, harnessing Shell Canada's local strategic agreements (National Blanket Orders) may simultaneously obtain best value for the project while resulting in local content procurement.

13.6. Quality Management

The Quest quality strategy is to implement three key quality programs:

1. Discipline Control and Assurance Framework (DCAF),
2. Technical Integrity Verification (TIV), and
3. Flawless Project Delivery (FPD)

The quality efforts are implemented by a Quality Focal Point who coordinates quality efforts project-wide.

Most of the Quality procedures and systems extend throughout the complete cycle of Project Realization, including design, engineering, procurement, fabrication, construction, testing, start-up and commissioning.

The Quality Management System also contains processes that are not a part of the main three systems and these are: Equipment Criticality Assessments, input to Contract language regarding quality requirements (i.e. Inspection and Test Plans, ITPs), and Reviews and Audits of the Quality Management System. Descriptions of all quality areas are provided in section 16 of the Quest Project Execution Plan.

13.6.1. Discipline Control and Assurance Framework

The Discipline Controls and Assurance Framework (DCAF) sets the corporate standard for Quality Control (QC) and Quality Assurance (QA) of discipline deliverables and events. As a part of DCAF, a Project Controls and Assurance Plan (PCAP) for the EXECUTE phase has been drafted and was used to form the structure of the EXECUTE phase workplan with the Capture EPCM Contractor. The DCAF incorporates the Technical Authorities from both P&T and UA.

The PCAP includes the list of Global Controls (standard throughout Shell) and the list of Project Specific Controls/Events. The Project Quality Focal Point is responsible for auditing and facilitating the DCAF process for Quest.

13.7. Construction

A Construction Execution Plan has been prepared, the primary objectives of which are:

- To ensure construction activities are carried out in accordance with corporate and Quest Project HSSE objectives
- To supports the prequalification assessment process regarding construction contractor capability (in all areas: HSSE, quality, capacity, etc)
- To document construction management plans required for offsite module fabrication, logistics, infrastructure, and onsite construction
- Regarding wells: to ensure that the environmental impact is minimized and the environmental footprint is as small as feasible for wellsite construction

The major scopes of work to be managed and delivered by the Construction Management Team(s) are as follows:

- Offsite module fabrication
- Onsite construction of the Capture facility at Scotford

- Field construction of the Pipeline and Wellsites
- Development of temporary infrastructure required to support onsite construction
- Transportation of materials, equipment, modules and resources to the Scotford site and to the field construction locations

Construction for capture will be managed by Fluor. The pipeline and wellsites construction will be managed by Shell Canada and contracted mainly to Tri-Ocean. The wells will be delivered by Shell E&P Wells department (Engineering and Operations).

For details on Work Optimization Strategies, Labour Relations, and Logistics & Infrastructure, please consult section 21 of the Project Execution Plan.

13.8. Management of Change

Management of Change (MOC) applies to the project's scope, estimated cost, estimated schedule, and production performance. All changes proposals must be identified, recorded, evaluated, approved, and reported. The procedure for managing change during EXECUTE is documented in the Quest-specific MOC Procedure [Ref 13.1]

The intent of managing change during EXECUTE is to:

- Provide for systematic evaluation of potential changes and dissemination of change information to all affected parties;
- Manage staff time in respect of assessing change proposals;
- Identify when a proposed change needs to be formalized in the manner of a Change Proposal;
- Evaluate the impact of proposed change across all disciplines;
- Establish a review process and identifies roles and responsibilities in this process;
- Assure appropriate HSSE review;
- Assure Asset Integrity review; and,
- Facilitate quick and efficient documentation and communication of Change Proposals

13.9. Interface Management

An interface management process has been established that will facilitate the timely identification and resolution of project interfaces. Effective interface management is a key element of sound project management and is a critical success factor to ensure cost, schedule, safety and quality targets are met. The key aim is to provide a consistent cross-project method by which interfaces can be identified, developed, mutually agreed, managed, tracked, controlled and closed out.

The Interface Management Plan (IMP) provides:

1. A consistent approach for achieving alignment between work areas
2. A process for initiating information requests
3. An auditable trail for interface transfers
4. A process for resolving difficulties or disputes
5. A process for managing changes arising that affect project activities

Quest Project interfaces are depicted in the picture below *Figure 13-4 Quest CCS Project Interfaces*:

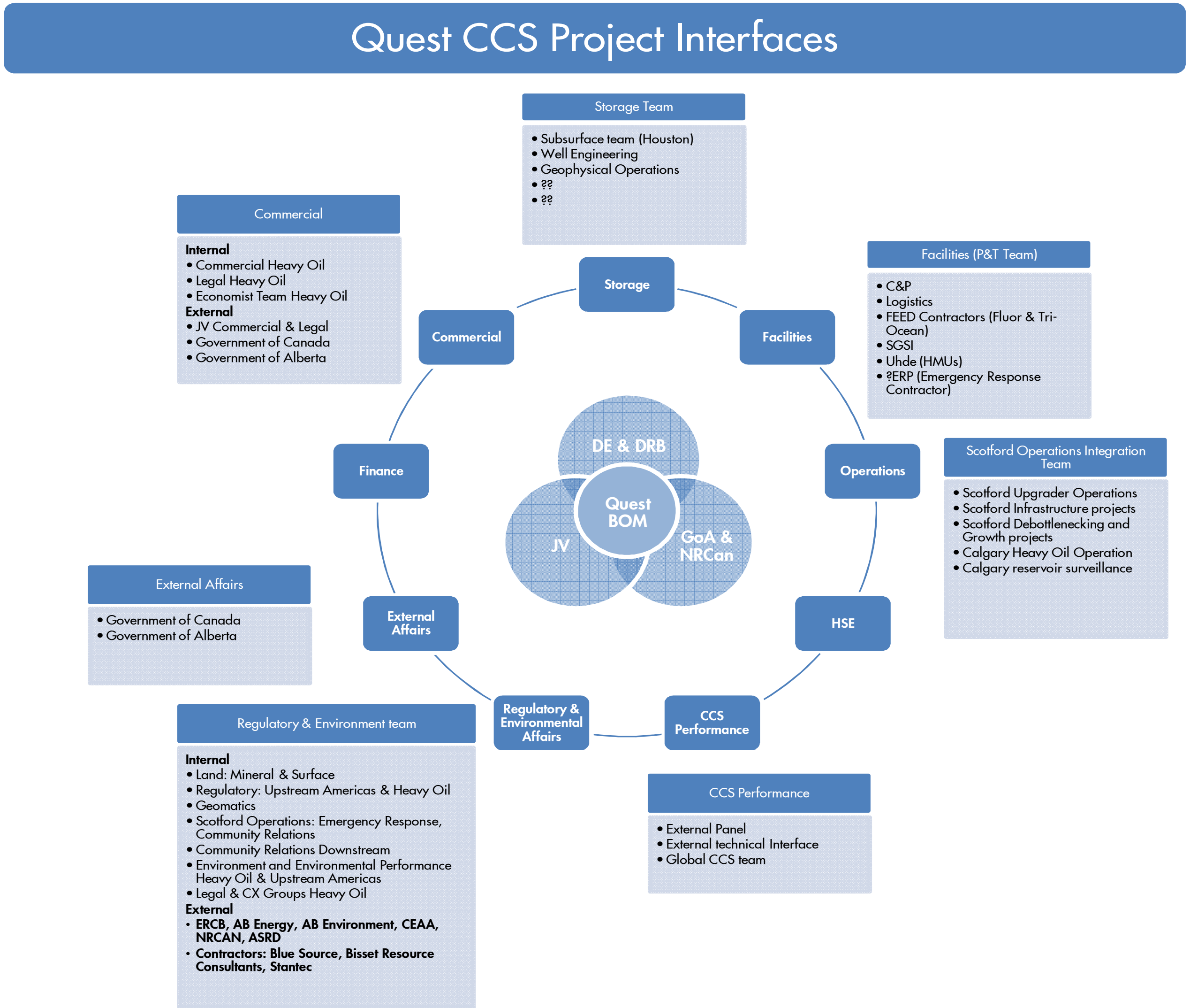


Figure 13-4 Quest CCS Project Interfaces

13.10. Information Management

This section provides an overview of Information Management for the Quest project. For more detail please consult the IM Strategy [Ref 13.3] and the Information Management (IM) Plan [Ref 13.4]

The objective of the Information Management Strategy (documents, data, and knowledge) is to enable effective information distribution to all project & facility stakeholders in a timely manner. This Strategy addresses deploying IM Global Standards and ensuring that project information requirements are accurately handled through the life of the project. The Quest IM Strategy in detail can be found following this Link IM Strategy.

Below is a summary of the areas the IM Strategy addresses:

- Align Information Management activities to project and business processes by:
  - Regular scheduled meetings with stakeholders to ensure expectations are met
  - Approving IM activities with project team leads
  - Clarify all strategies and plans with team leads
  - Maintain IM risks in project Easy Risk
- Create an IM organization to assist the project needs, IM Lead and a Doc Control Office to handle all project document and data requirements for the life of the project.
- Support the flow of information throughout the project phases by
  - Interviewing key stakeholders to better understand the flow of information
  - Assist in the review process for DCAF/PCAP deliverables
  - Assist in the Regulatory submission
- Provided IM contract information to SCM/Procurement Lead
- Manage all deliverable documents for the project including Shell and external contractors by:
  - Use of the Quest Document Numbering Procedure
  - Use of the Quest Information Handover Guide
  - Define Handover plans for project documentation from Project phases
    - Critical documents
    - Non Critical Documents
- Manage the control of data created during the project by:
  - Data loading the Asset Hierarchy in the data warehouse from contractors in timed intervals that meet the project needs
  - Communicating Shell standards to contractors who provide data to Shell to ensure the quality and consistency of this information
- Manage the handover of information to Operations that will address the information created by operations for the following:
  - Physical Plant

- Information – documents, data and drawings
  - Critical documents gathered from operations
  - Non Critical documents
- Information in database format
  - SAP, SPI, etc. that will populate operation applications (i.e., Systems Applications and Products (SAP), Operational Integrity Assurance (OIA), Reliability Centred Maintenance (RCM), etc.)

The Information Management (IM) plan can be found in the Quest Capture BDP. The IM plan shall be maintained and refined throughout Define and Execute Phases.

13.11. Improvement Plan

During the SELECT and DEFINE phases, the project plan for application of VIPs was developed in conjunction with the EPCM contractor. By using multi-discipline teams and external third-party participants, value improvement ideas were identified, developed and implemented; the effect was a >15% reduction in CAPEX prior to completion of the VAR3 estimate. A selection of VIP practices for the Capture scope has been included in the EXECUTE phase schedule and execution. VIP closure is and will continue to be a KPI.

In addition, the EPCM contractor has established a Value Awareness program to facilitate the ongoing collection of ideas to reduce costs from the integrated team. A Value Awareness committee has been established comprising Shell and EPCM personnel to review and approve ideas as appropriate.

13.12. Knowledge Management Plan

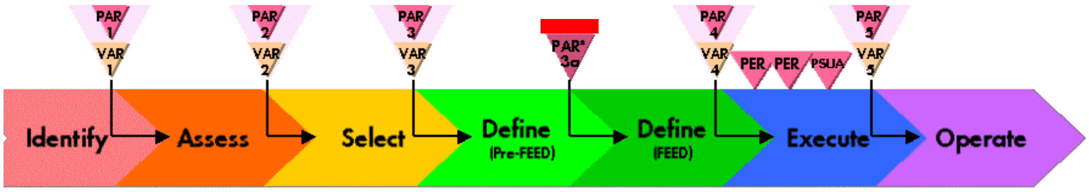
The project's knowledge sharing plan [Ref 13.5] has been developed to align with the knowledge/information sharing commitments, particularly with the Government of Alberta (GOA). The plan identifies 6 main areas for knowledge sharing - i.e. Capture, Transportation/Pipeline, Storage, CCS Value Chain, Regulatory Approvals, and Cost & Revenue. The specific information/knowledge required (either qualitative and/or quantitative through various project documents, drawings and reports) for each of the sub-areas will be identified and a responsibility matrix developed around ownership/responsibility and frequency of issuance to meet the commitment with the Government. The plan has been designed to take into account the timing of when a particular information/knowledge will be required at the different stages of the project i.e. Concept stage, Define phase, Design & Engineering, Construction and Operation (before start-up and after start-up) phases.

Tools, systems and processes/protocols have been designed to capture and transmit the information/data/knowledge. The project's information management process will be followed in capturing and disseminating the information/knowledge. Discussions are near complete on the use of an external web-based system - "4 Projects" - as the repository of all the information/documents/reports required by the GOA. The "4 Projects" system will be administered by a 3rd Party company contracted by the Quest project to provide the service covering the entire duration of the project and up to the period when the project's knowledge-sharing obligations with the Government end.

- Annual reports on project status/progress, performance and results of the MMV programme will be issued to the Governments of Canada and Alberta. Updates to the MMV Plan and Closure Plan will also be issued to the both governments every 3 years.
- Internally, lessons learned (LL) and Retention of Critical Knowledge (ROCK) sessions will be held to capture project lessons and CCS specific knowledge for input into the Shell Global lessons learned database and the Shell CCS Centre of Excellence (COE) for future (CCS) projects within Shell.
- There will be speaking engagement sessions and forums with external bodies (i.e. universities, CCS conferences, etc.) to share the knowledge and best practices from the Quest CCS project.

13.13. Project Assurance

13.13.1. ORM Deliverables by Project Phase



Phase Objectives	**<u>Business Planning</u>** Identify options Economic evaluation SD strategy Opportunity Framing workshop Assurance Reviews	**<u>Business Planning</u>** Assess & select best options Economic evaluation SD strategy Project Assurance Plan (PAP) ± 30% Estimate Assurance Reviews	**<u>Basis for Design</u>** Optimum technology Operational requirements Site Selection HSSE assessment Economic Evaluation ± 30% Estimate Assurance Reviews	**<u>Process Design</u>** Fully defined process scope (PFD's) Economic Evaluation Risk Review HSSE assessment Execution & Ops Planning ± 20% Estimate Assurance Reviews	**<u>Basic Engineering Design</u>** Complete Project Specification Final Economic Evaluation Integrated EPC & Commissioning schedule Execution & Ops Planning ± 10% Estimate Assurance Reviews	Design Procure Construct Assurance Reviews	Flawless start-up Flawless first cycle of operation Meet business plan PIR
Phase Deliverables	Schedule Estimate Risk Register Opportunity Framing report Assurance Review Reports	PAP Project Premise Document (PPD 0) Scouting report Project Execution Strategy (PES 0) Operations Implementation Plan (OIP 0) Technical Assurance Plan Risk Register Schedule Estimate Assurance Review Reports	Updated PAP PPD Rev.1 Basis of Design (BOD) PES Rev.1 OIP Rev.1 Technical Assurance Plan Risk Register Schedule Estimate Assurance Review Reports	Updated PAP PPD Rev. 2 Basic Design Package (BDP) Project Execution Plan (PEP) OIP Rev. 2 Risk Register Schedule Estimate Assurance Review Reports	Updated PAP PPD - Final Project Specification (PS) PEP Rev. 1 OIP Rev. 3) Risk Register Schedule Estimate Assurance Review Reports	Updated PAP Safe, environmentally sound, operatable facility Assurance Review Reports	PIR Report

Figure 13-5 ORM Deliverables by Project Phase

13.14. Operations, HSE and Risk Management

The purpose of commissioning is to prepare the plant for operation. The purpose of performance testing is to prove that the plant meets the guaranteed performance values. The Operations Readiness Plan (ORP) addresses these subjects in detail.

The most important objective for the Quest project is Goal Zero. For Quest, Goal Zero means:

- Zero Lost Time Incidents
- Zero Total Recordable Incidents
- Zero significant environmental incidents

The project will support Goal Zero through the 12 Life Saving Rules and a zero tolerance attitude towards infringements. Specific plans and activities will be implemented through a project HSSE plan [Ref3.1]

The HSSE Plan enables the project manager and venture manager to:

- identify the HSSE requirements for the project
- structure the project plans to successfully implement HSSE requirements during all project phases

In addition, the project leadership team will take responsibility for implementing these objectives and will have Quest specific objectives as part of their Goal Performance Appraisals (GPAs).

One of Shell's key HSSE requirements is to demonstrate that HSSE risks from its operations are As Low As Reasonably Practicable (ALARP). An HSSE Design Case [Ref 13.6] demonstrates that the Hazard and Effects Management process (HEMP) has been applied throughout the project development. As a result, the project will demonstrate that the process hazards associated with the design have been managed and reduced to a level as low as reasonably practicable (ALARP).

The HSSE Design Case will be the auditable record for HSSE and will be continuously developed throughout the project.

The goal of Risk Management is to identify and evaluate the significant risks to the achievement of the project objectives, set boundaries for risk acceptance, and apply fit-for-purpose responses.

Risk Management applies equally to upside risks ("opportunities") and downside risks ("threats") to maximize the likelihood of the project achieving its objectives while maintaining risk exposure at an acceptable level. Therefore, both threats and opportunities are explicitly included in the project Risk Register.

Project risks are being managed using the TECOP (technical, economic, commercial, organizational and political) approach outlined in ORM PS20 Risk Management. Risks are identified, categorized and assessed to identify owners and put mitigation plans in place to manage the risks.

14. START-UP AND COMMISSIONING

The owner organization is responsible for the start-up and commercial operations of the CO_2 capture facilities as well as the pipeline and wells. The contractor will provide adequate timely assistance during start-up for the rectification of defects. A dedicated crew who are not involved in ongoing construction or commissioning activities should perform this work.

14.1. Systemization

Preliminary system definition within Quest area has been completed and scrutinized by operation. A priority list is also made for identifying which system should be available first (in blocks) in order to reduce start up time. All systems will be marked on the P & I diagrams.

All mechanical works for Expansion 1 (HMU3) along with common systems will be completed early followed by base plant (HMU 1&2). Amine regeneration / TEG and CO_2 compressor will be started early followed by lining up of each Amine absorber associated with each HMU in series depending on completion of work in each unit.

The staggered start-up scenario (HMU3 + p/l + wells, then HMU1 and 2) offers the benefits of an early commissioning of the p/l and subsurface facilities. The 2015 base plant turnaround will occur during spring time which will require around 3 weeks of complete capture shutdown.

14.2. CSU Sequence

The start-up schedule is developed in consultation with pipeline and storage teams. The well start-up base case is utilized for development of the CSU Schedule. Considerable effort was made to align overall schedule along with CSU activities.

The strategy is to start all the utilities and common systems first. That includes waste water and cooling water. A system cleaning matrix is being developed for all commodities. Steam blowing of large LP steam headers and chemical cleaning of Amine system will be completed as part of pre-commissioning activities. A compressor pre-commissioning and surge test will be completed in advance. Amine circulation will be established followed by lining up of Absorbers. It is envisaged that the Expansion 1 absorber will be started first in Q4 2014. Pipeline and wells will be made ready in advance to receive CO_2 from capture unit as soon as HMU3 is ready for start-up. The period between start-up of HMU3 facilities and the planned shutdown in 2015 will be used to start-up the initial injection wells. The start up of the wells will commence once the surface facilities have completed the pre start-up checks; pipeline has been hydro tested, pigged and is ready for commissioning and the wells telemetry system is working to record real time injection pressures temperatures and rates. The wells commissioning will commence after the pipeline is full of CO2 and the system pressure is high enough to commence injection.

Well start-up activities supporting system integrity checks and early data acquisition requirements by the storage team are expected to continue until the shutdown in Q2 2015. After the shutdown, expected to last about three weeks, all three absorbers will be lined up including Base Plant units to bring the system to full design capacity.

A detailed system based start up schedule will be completed before VAR 4. The strategy will be to turn over the system to operations as per the agreed project schedule (According to system priority).

- The bulk of the process equipment will be tested prior to commissioning (e.g. utilities, TEG, compressor) to prove the integrity and operability.
- On completion of the above, the systems will be turned over on a system-by-system basis based on a priority matrix.

14.3. Well start up strategy

The wells start-up strategy base case scenario consists of the following:

- Each well will be conditioned prior to initial start-up, by displacing test water with CO2 using a CO2 truck
- As HMU3 is online in December 2014, injection will start in January 2015 in one well (Radway 8-19). After a 10-day ramp up, injection will continue at maximum available rate (40% of total rate) for at least 15 days or until stable injectivity is demonstrated. This will conclude the start-up of the first well.
- Injection will then continue in this first well until either:
    - HMU2 turnaround forces a system shut-down (currently planned for two weeks in mid-March 2015), or
    - Pressure response is seen in the adjacent injectors waiting to be started up (interference test)
- If stable injectivity has been demonstrated in the first well and a pressure response has been seen in the adjacent injectors before HMU2 turnaround, the next wells can be started sequentially following the same scheme: 10-day ramp up followed by 15 days injection at target rate or until stable injectivity is demonstrated.
- If stable injectivity has been demonstrated in the first well but no pressure communication has been proven between injectors before HMU2 turnaround, the next injectors will be started after the turnaround, following the same start-up scheme as for the first well. One well should be ramped up only once the ramp up period of the preceding well has been completed, and if extra capacity is available. Depending on the first well ramp-up it may also be decided to shorten the next wells ramp-ups.
- If stable injectivity requires a longer time than anticipated when starting up an injector (>25 days), the wells should be started soon enough to ensure that all of the injectors have completed the required time for stabilising injection in the first

well (and at least a 25 day start-up cycle) before Q4 2015, irrespective of the pressures stabilising or a response noted at adjacent injectors. Ramp-ups may have to be done simultaneously to meet this deadline.

- This start-up strategy should maximise the information gathered during the start-up of the system and also enable meeting the "Commercial Operations" requirements before the contractual deadline at the end of 2015.
- For the wells start-up timeline see APPENDIX 9.

14.4. CSU key steps to Commercial Operations

A production ramp-up to meet design capacity is planned to take place within two weeks of introducing raw H_2. Between one and three months after lining up all three absorbers, performance guarantee test runs for the CO_2 Capture are planned to assess compliance to the design. Non-compliance will be addressed and corrected under the warranty.

Following the initial start-up three performance tests are included in the schedule to achieve successful commercial operation and trigger payment of Government funding. These tests have been defined as part of the Funding Agreement as follows:

- **Test A: capture capacity**
  24 consecutive hours in which the Quest capture unit processes a minimum of 2,960 tons (= 100% of the committed commercial daily rate) of CO_2 from the Scotford Upgrader Base and Expansion HMU facilities.
- **Test B: capture efficiency**
  20 consecutive days in which the Quest capture efficiency is above 75% of the total CO_2 produced by the Scotford Upgrader Base and Expansion HMU facilities during those 20 days. The minimum production rate during the 20 days period is 35 T/hour (840 T/day) at all time, and 58 T/hour on average (1,392 T/day)
- **Test C: integrated project reliability**
  30 consecutive days in which the Quest project maintains operation whereby the capture, transportation and subsurface facilities operate continuously without shutting down. Over these 30 days, the total tonnage of CO_2 stored into the target geological formation must be a minimum of 30% of the expected annual production rate of 1.08 million tons, or 26,640 tons.

For more information about CSU and Start up schedule please refer to the ORP [Ref.14.].

15. CLOSURE, POST CLOSURE, DECOMMISSIONING AND ABANDONMENT

Shell intends to meet all applicable regulatory requirements related to the reclamation, decommissioning and abandonment of the Project components as stipulated in the Oil Sands Conservation Act (OSCA) and the Environmental Protection and Enhancement Act (EPEA). In Alberta, the ultimate reclamation goal is to achieve land capability equivalent to pre-development conditions, as stated in the Conservation & Reclamation (C&R) Regulation of EPEA. Section 137 of EPEA states that an operator must conserve and reclaim specified land, and obtain a reclamation certificate. Project specific conservation and reclamation requirements will also be prescribed in the Alberta Environment (AENV) EPEA Approval.

A map of the Project Area and Development Area is provided below in *Figure 15-1 Quest CCS Project Components and Area of Interest*. The decommissioning and abandonment of all assets, including wells, production facilities, pipelines and infrastructure, that have reached the end of their useful life, shall be completed in accordance with legislative requirements and Group standards.

Decommissioning and abandonment plans and procedures have been developed for the project and reside in the following documents:

1. C&R plans wells and pipeline
2. Environmental Protection Plan for the pipeline
3. Scotford Upgrader Reclamation plan
4. Quest Closure plan

Conservation and Reclamation (C&R) Plans for the wells and pipeline have been created and was submitted as a part of the Environmental Assessment in November 20110. It is expected that the Co2 capture portion of Quest will fall within the Reclamation activities of the Scotford Upgrader.

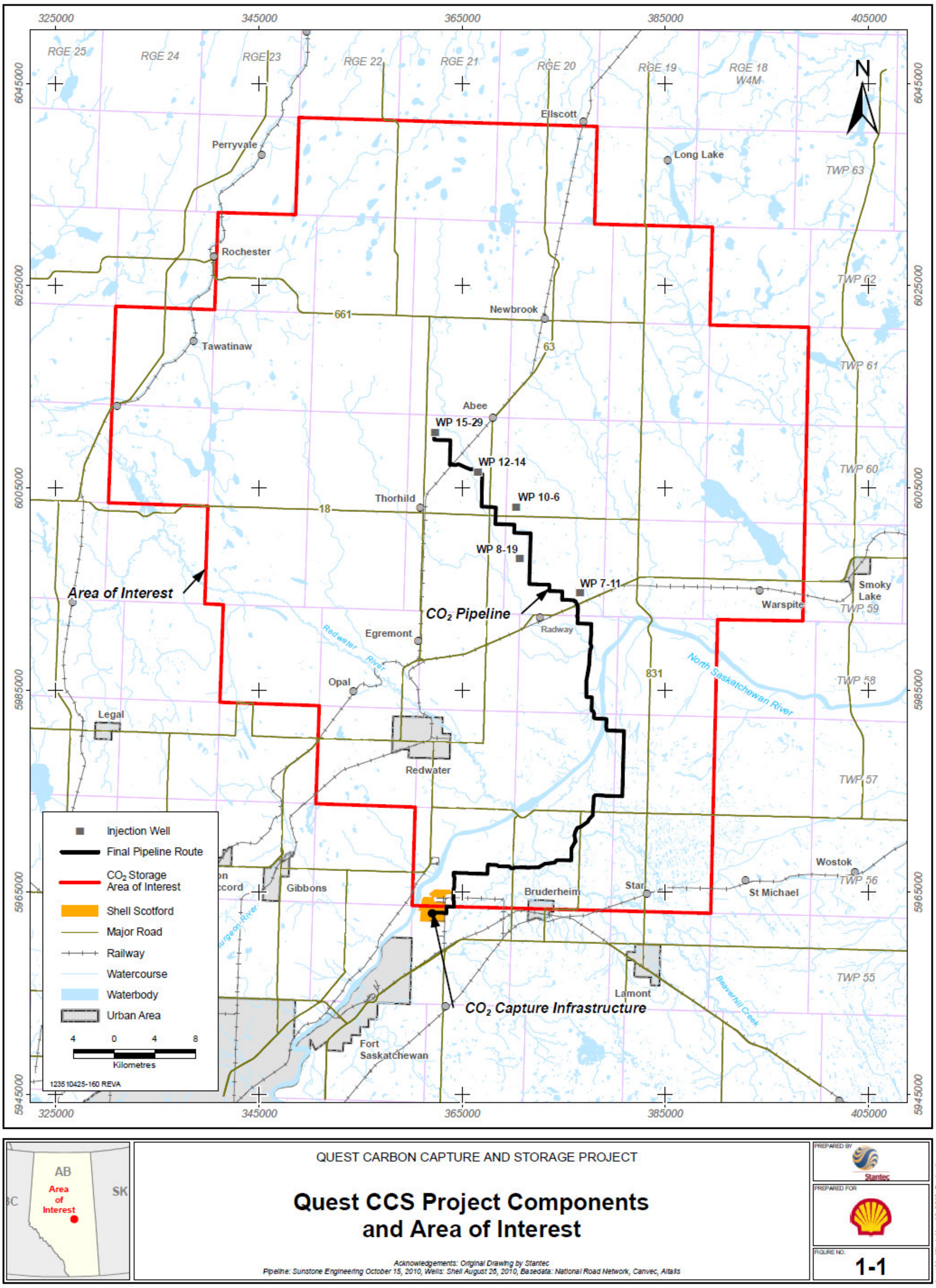


Figure 15-1 Quest CCS Project Components and Area of Interest

The C&R Plans describes the conservation and reclamation measures to be implemented throughout the Project life to minimize potential environmental impacts identified in the EIA and to achieve equivalent land capability for the reclaimed areas at Project closure. The C&R Plans also provides a general guideline for reclamation with the following objectives:

- Surface disturbances will be reclaimed to provide equivalent land capability
- Reclaimed areas will be compatible with the surrounding area and land use, including agriculture, forested areas, wetlands, and streams
- Reclaimed lands will provide for maintenance-free, self-sustaining ecosystems with a similar range of potential end uses including agriculture, forestry, wildlife habitat, and traditional use, compared to pre-disturbance conditions.

Additionally closure activities are described in the Quest Closure plan that was submitted in May 2011 [Ref 15.1].

15.1. Legislative framework

Reclamation activities in the province of Alberta are regulated under the Environmental Enhancement and Protection Act. Reclamation and closure activities of the storage component of Quest are regulated under Carbon Sequestration Tenure Regulation.

The Project will achieve full, sustained operations by the fourth quarter of 2015 and injection will continue for the life of the Scotford Upgrader (greater than 25 years). At that time, CO2 injection will cease and site closure activities will take place. This post-injection period is known as the closure period, and Shell anticipates this period will take place across 10 years post-injection.

Following the completion of site closure activities, Shell will apply for a Site Closure Certificate, in accordance with prescribed criteria. Following issuance of a Site Closure Certificate, the closure period will end, and the post-closure period will begin. With post-closure, long-term liability will transfer to the province, and any further post-closure activities will be the responsibility of the province.

Requirements on the operators during the closure period are subject to update by the province. Alberta Energy has also initiated a Regulatory Framework Assessment (RFA) review process that will advance technical understanding of CCS storage and could result in new regulatory requirements for closure. Current obligations to the Government of Alberta are outlined in Alberta's CCS Act and include:

- Submitting a measurement, monitoring and verification (MMV) plan for approval
- Complying with the approved MMV plan
- Providing ongoing reporting, which describes compliance with the MMV plan

- Submitting an updated closure plan every three years during the lease, and a final closure plan for approval three years before planned cessation of injection

The initial Closure Plan for the Quest Project was included with the Carbon Sequestration Lease Applications, and is integral to the six Carbon Sequestration Leases that were subsequently issued to Shell as part of the Quest Project below [Ref 15.1]

15.1.1. Site Closure Performance Targets

The following performance targets formed the basis of the Quest Closure Plan.

The Alberta Department of Energy (ADOE) RFA process will examine and potentially develop technical criteria for site closure. Until that time, the following high-level qualification goals for site closure have been utilized, adapted from guidelines developed by an international third-party organization in collaboration with industry partners (DNV 2010a) and a Directive developed by the European Parliament and Council regarding the geological storage of CO2 (2009).

To meet these high-level goals, MMV activities will be designed to deliver against the following targets during the site closure period.

15.1.1.1. CO_2 Inventory Accuracy Target

To establish confidence that the conditions for site closure have been met, the accuracy of the reported inventory of CO2 stored will comply with regulations and protocol.

15.1.1.2. Containment Performance Target

It is essential to assess whether any migration of injected CO2 or BCS brine has occurred and whether any identified migration has damaged the environment or human health. The following performance target has been adopted.

- Measurements of any changes within the hydrosphere, biosphere, and atmosphere caused by CO2 injected into the BCS storage complex are sufficient to demonstrate the absence of any significant impacts as defined by the Environmental Assessment."

The approved MMV Plan will provide more details regarding performance targets for containment.

15.1.1.3. Conformance Performance Target

It is also essential to assess whether injected CO2 and BCS brine behaves as expected and how site performance evolved relative to the predictions. As such, the following performance targets have been adopted:

- Actual storage performance conforms to predicted storage performance within the range of uncertainty.
- Knowledge of actual storage performance is sufficient to distinguish between two classes of possible future performance: those that result in permanent stable storage of the target mass of CO_2 inside the BCS and those that do not.

The Quest MMV and Closure Plans have been designed to meet these targets through a systematic:

- Documentation of expected performance (Model based forecasts)
- Acquisition of the information to meet the performance targets for closure
- Reconciliation of that information
- Update the model based forecasts
- Document any changes to the operating plan as a result of collected information

Following site closure activities, Shell expects to apply for a Site Closure Certificate provided there are no significant issues that arise from Project operations and that storage performance and CO_2 and brine containment in the BCS storage complex are demonstrated to the satisfaction of the Crown in accordance with pre-agreed upon criteria.

The post-closure period will occur following the issuance of a Site Closure Certificate, which will transfer the long-term liability from Shell to the Crown. Shell is committed to advising the Government of Alberta on its long-term monitoring approach and sharing its accrued knowledge and experience to the government prior to this transfer. *Figure 15-2 Proposed Timeline for Project Operations, Closure and Post-Closure* for a timeline of the proposed time closure activities.

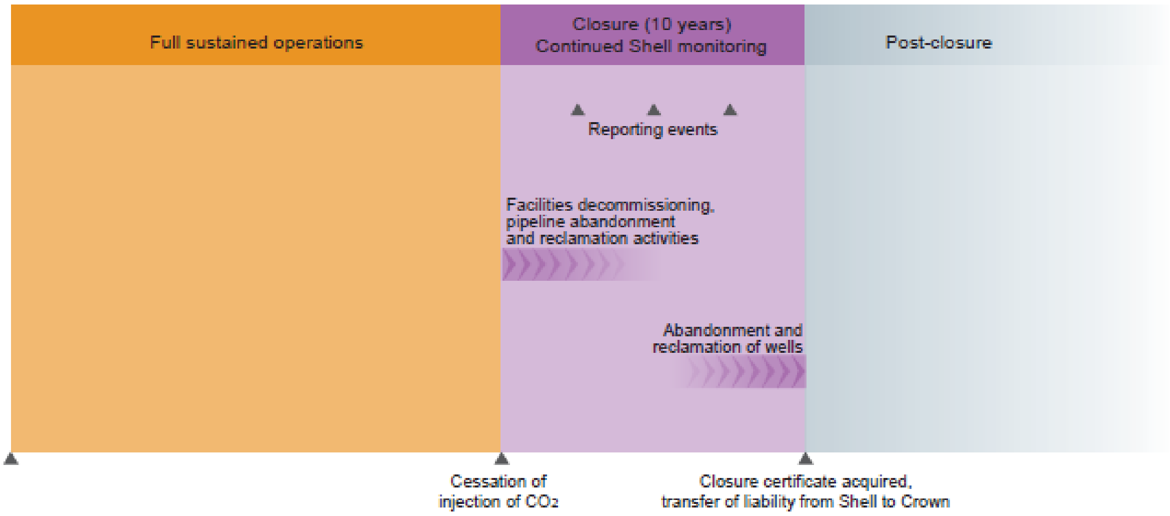


Figure 15-2 Proposed Timeline for Project Operations, Closure and Post-Closure

16. STORAGE AND MMV COSTS AND SCHEDULE

The storage and MMV plan are designed to tie into the major project schedule. The Integrated Storage Schedule is in APPENDIX 4. This schedule illustrates the key project tie in points relevant to the Storage timeline on the top line for example:

- The pipeline order and construction points
  - The final decision on how many wells are required for start-up must be made by this point. Therefore the injection well #2 and #3 must be drilled in Q2/Q3 2012.
  - The Deep MMV wells can only be finalised once the proposed target formation of the Winnipegosis or Cooking Lake have been analysed in the injection wells drilled in 2012.
  - The SDP needs to be revisited based on the results of these wells.
- The HMU tie-ins.
  - All wells need to be drilled hooked-up and conditioned prior to this time.
  - The well start-up is impacted by the phased HMU start-up.
  - This also provides the opportunity for pressure monitoring in the wells not injecting during start-up to get a potential early confirmation of reservoir connectivity.
- Start-Up
  - All baseline activity needs to be documented prior to start-up
  - The MMV plan and Closure Plan needs to be re-visited once the baseline data has been analysed.

The CAPEX and OPEX cost estimates for the 3, 5 and 8 well cases can be found in APPENDIX 10.

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18. NOMENCLATURE

ADIP-X	
AENV	Alberta Environment
ALARP	As Low As Reasonably Practicable
API	American Petroleum Institute
ARP	Asset Reference Plan
AUC	Alberta Utilities Commission
BfD	Basis for Design
BHP	Bottom Hole Pressure
BOP	Blowout Preventer
BPVT	Back Pressure Valve Threads
C&R	Conservation & Reclamation
CAPEX	Capital Expenditure
CBS	Cost Breakdown System
CCP	Change Control Panel
CCS	Carbon Capture and Storage
CMEP	Construction Management Execution Plan
CNRL	Canadian National Resources Ltd.
CO_2	Carbon Dioxide
cP	Centi Poise (unit of viscosity)
CP	Change Proposal
CRA	Corrosion Resistant Alloy
CSU	Commissioning and Start-Up
CSLF	Carbon Sequestration Leadership Forum
CVG	Casing Vent Gas
DCAF	Documents control Assurance Framework
DCC	Document Control Centre
DCS	Distributed Control Systems
DEP	Design and Engineering Practice
DG	Decision Gate
D&R	Decommissioning and Reclamation
DRB	Decision Review Board
DTS	Distributed Temperature Sensor
EDMS	Electronic Document Management System

EIA	Environmental Impact assessment
EOR	Enhanced Oil Recovery
EP	(Shell) Exploration and Production
EPEA	Environmental Protection and Enhancement Act
ERCB	(Alberta) Energy Resource Conservation Board
ESAR	Estimate and Schedule Assurance Review
ESTG	Engineering Standard and Technical Guideline
EUA	Electric Utilities Act
EUB	Energy Utilities Board (EUB)
FAT	Factory Assurance Test
FDP	Field Development Plan
FeS	Iron Sulphide
FID	Final Investment Decision
GHG	Greenhouse Gases
GIIP	Gas Initially in Place
HEE Act	Hydro and Electric Energy Act
H_2S	Hydrogen Sulphide
HEMP	Hazard and Effects Management Process
HIC	Hydrogen Induced Cracking
HMU	Hydrogen Manufacturing Unit
HP	High Pressure
HRSG	Heat Recovery Steam Generator
HSE MS	Health, Safety and Environmental Management System
HSSE	Health, Safety, Security and Environment
IM	Information Management
IPCC	Intergovernmental Panel on Climate Change
IPMS	Integrated Project Management System
IPR	Intellectual Property Rights
ISO	International Standards Organisation
IT	Information Technology
JURAT	data base repository for stakeholder information
K_a	Absolute Permeability
K_h	Horizontal Permeability
kPa	KiloPascal

K_v	Vertical Permeability
LSD	Legal Surface Description
M2M	Metal to Metal
MARP	Measurement, Accounting and Reporting Plan
mD	MilliDarcy
MDEA	Methyl Di Ethanol Amine
MMV	Measurement, Monitoring and Verification
MoC	Management of Change
MPa	MegaPascal
MW	MegaWatt
MVC	Multiple Vapour Compression
NFA	No further activity (Harvest production)
NGO	Non government organizations
NPS	Non Point Source
NPV	Nett Present Value
OIA	Operations Integrity Assurance
OPEX	Operating Expenditure
OPMG	Opportunity and Project Management Guide
OR&A	Operations Readiness and Assurance
ORP	Opportunity Realisation Process
OSCA	Oil Sands Conservation Act
PAP	Project Assurance Plan
PBTD	Plug Back Total Depth
PCAP	Project controls and assurance plan
PCP	Project Controls Plan
PCR	Project Change Request
PDAB	Project Delivery Assurance Board
PDF	Probability Distribution Function
PE	Project Execution
PES	Project Execution Strategy
PMI	Project Management Institute
PWR	Process Worth Replicating
QM	Quality Management
QMS	Quality Management System

QRA	Quantitative Risk Analysis
RAM	Reliability and Maintenance
RAM	Risk Assessment Matrix
RF	Recovery Factor
RHC	Resid HydroConversion
RHOB	Gamma Ray Bulk Density
RM	Risk Management
RMS	Risk Management System
R_w	Formation Water Resistivity
SAT	Site Assurance Test
SCAN	Shell Canada
SCC	Supply Chain Council
SCM	Supply Chain Management
SC-SSSV	Surface Controlled, Sub-Surface Safety Valve
SD	Sustainable Development
SOHIC	Stress-Oriented Hydrogen Induced Cracking
SP	Social Performance
SPE	Society of Petroleum Engineers
SPP	Social Performance Plan
SSC	Sulphide Stress Cracking
S_w	Water Saturation
T&Cs	Terms and Conditions
TA	Turnaround
TAP	Technical Assurance Plan
TB	Tender Board
TDS	Total Dissolved Solids
Twps	Townships
UA	(Shell) Upstream Americas
VAR	Value Assurance Review
VIP	Value Improvement Process
V_{sh}	V shale
VSP	Vertical Seismic Profile
W4M	West of the 4th Meridian
WBS	Work Breakdown Structure

WCFN	Woodland Cree First Nation
WMS	Well Manufacturing Systems
WRM	Well and Reservoir Management
WTI	West Texas Intermediate
XRD	X-ray Diffraction
Φ	Porosity

APPENDIX 2. ITERATIVE MODELLING STRATEGY

Quest Subsurface Modelling Strategy

	Type/Description	Topic	Inputs	Variables	Outputs	Learnings
Generation 1	**Gen1 Full Field Models**	**Project Screening, FPP Submission** and planning of 1st appraisal campaign	**Regional formation properties** (105 wells in BCS, 88 used for structural, 49 for PP input)	Reservoir quality, BHP constrained injection	Pressure contours, CO2 footprint, # of injector wells	Base case of 5 injector wells is sufficient
Generation 2	**Gen2 Full Field Models**	Project feasibility assessment and **Exploration Tenure**	As above and updated by **SF, RW** appraisal well results.	Reservoir quality, BHP constrained injection	Pressure contours, CO2 footprint, # of injector wells	Low case of 1 injector well feasible, base case of 3 wells confirmed, high case of 7 wells
	Gen2 Sector Model	**Exploration Tenure**, sensitivity assessment of plume migration and trapping mechanisms	As above with the addition of connectivity updated by **RW 3D seismic mini-survey**	Formation connectivity, reservoir quality, BHP constrained injection, injected volume down-scaled to model size	Pressure contours, detailed CO2 footprint, # of injector wells	Key sensitivities driving plume migration and trapping are permeability, and relative permeability.
	Gen2 Interference	**Exploration Tenure**, Urban planning assessment while including "competing" inection projects at pore space boundary.	As Gen2 Full Field model with the addition of compeating schemes at NE and SW pore space boundaries (each 1.2 Mtpa for 25 years)	Base case Gen2 models with varying total injection rates	Pressure contours, CO2 footprint, # of injector wells and inhibited well rates at inteference between the schemes.	Competing "Quest like" injection schemes right at the tenure boundary would inhibit Quest injectivity by 2025.
	Gen2PLus Full Field Models	**Funding Agreement**, Low Connectivity case to de-risk feasibility assessment	As above with the addition of connectivity updated by **RW 3D seismic mini-survey**	Formation connectivity and reservoir quality, BHP constrained injection	Pressure contours, CO2 footprint, # of injector wells	A 7 well development is feasible to mitigate this low case scenario.
	Gen2 radial TOUGHREACT Model in BCS	Geochemical alteration of BCS formation and brine, halite precipitation CO2 path ways	Gen2 base case formation properties, layered perm model as per Scotford appraisal well	Single injector of a 3 well development with down-scaled injected volume (1/3), kv/kh of high perm layer as variable	Halite dry-out zone, pressure profile,CO2 pume reach and dynamics of trapped volume fractions	Dry out zone of 60-70m estimated.

	Type/Description	Topic	Inputs	Variables	Outputs	Key Learnings
Generation 3	**Gen3 Full Field Models**	**Regulatory Submission**, Storage Complex	Regional formation properties, updated by **SF, RW** appraisal wells, **2D & 3D seismic results and HRAM**	Formation connectivity, reservoir quality and facie distribution, BHP constrained injection	pressure contours, CO2 footprint, # of injector wells	Confirmed the project description and well count between 3 to 10 injector wells
	Gen3 Full Field Model + High Perm Basal Layer	**Regulatory Submission**, Storage Complex, High Permeability Thieve Zone	As above plus 8m high permeability layer at BCS/Precambrian	Base layer 10-20D perm, 8m thickness, variable kv/kh of BCS, BHP constrained injection	Pressure distribution and CO2 plume geometry	While a high perm basal layer certainly acts as a pressure sink, CO2 will quickly migrate back into the BCS due to buoyancy.
	IPSM Study	Compressor Selection and Pipeline Size	Generation 3 range of injector well count and BHP constrains.	Number of injection wells, pipeline length and size, length of laterals, seasonal variations in ground temperature, compressor discharge temperature	Required discharge pressure to drive the integrated system.	A compressor discharge pressure of 14.5 Mpa under discharge temperature control and a pipeline size of 12" provides a robust development concept.
	Surface Heave Models	InSaR Feasibility and input to well bore stability models	Gen3, 3 well and 7 well pressure field (worst case for localized pressure effect)	Elastic formation properties	Surface heave and stress field near well bore	A surface vertical uplift of approx. 40 mm was estimated for the reference case after 25 years of injection.
	Radial TOUGHREACT model in BCS+LMS+MCS	Geochemistry in Storage Complex	Brine and matrix composition(s)	Permeability profile & kv/kh	"Trapped volume count", halite dry out zone, alteration of primary seal	BCS is geochemically inert, adding reactive transport modeling will have no impact on filed development decisions (plume size, pressure front), on average 3.7% of the CO2 is dissolved in brine, no mineral trapping until 100's of years post injection
	Radial TOUGHREACT model in Wapiti Formation	Shallow Aquifer Contamination (MMV)	Wapiti and BCS brine composition, GeoChem of Wapiti formation, BCS Pressure from Base Case Gen3 dynamic model	1. Leakage at Injector, 2. Leakage at MMV well (1 km), 3. Leakage at closest legacy well (20 km).	Concentration Maps around leaking well, changes in rock and fluid chemistry including potential release of unwanted compounds.	Small amounts of As, Pb and Fe may be mobilized due to leakage of CO2 or CO2 saturated brine into shallow aquifers. Contamination front will only reach a few 100's of meters from leak point.

	Type/Description	Topic	Inputs	Variables	Outputs	Key Learnings
Generation 4	**Radial Sector Models**	**Detailed SDP**, Thermal Cooling and Well Start-up behavior	**Radway well results (core calibrated)**.	Thermal conductivity of formation, CO_2 injection temperature, grid size of model(s)	Formation temperature as function of distance from wellbore and time. Grid size around wells to avoid boundary effects	Cooling front reaches approx. 350m into formation (3 well development at 25 years). Formation takes a long time to re-equilibrate.
	Gen4 Full Field Pressure Models	**Detailed SDP**, Storage Complex, full-field pressure distribution	As Gen 3, updated with **Radway results, both well and geophysical data plus 1B seismic results**.	Reservoir quality, Formation connectivity and reservoir quality, BHP constrained injection	pressure contours, confirm # of injector wells, pressure at legacy wells.	Confirmed the range of required injector well count to be between 3 to 8 vertical injectors.
	Gen4 Plume Sector Model	**Detailed SDP**, CO_2 plume migration, conformance and detailed MMV planning	As Gen 3, updated with **Radway results and Radway 3D interpretation,**	Reservoir quality, 3D reservoir heterogeneity, well interference, static and dynamic reservoir properties, CO_2 injection volume.	Plume radius probability distribution, trapping efficiency, storage volume utilization	Sensitivity to Rel Perms. Conformance may drive final well count.
	Flow Assurance Models	Integrated System, standard operation and upset conditions, down-turn options	14.5 Mpa compresion system, 12" pipeline, pipeline topography	Rates, temperature, CO_2 composition	Operating envelop, hydrate formation risk, condensation.	Confirmed robust operating envelop without encountering hydrate issues.
	Surface Heave Model	**MMV Plan**, InSaR local calibration	Core calibrated Radway properties, formation temperature distribution, base case pressure distribution	Formation compressibility ranges, formation pressure	Surface heave and near wellbore stress field - reduction in fracture pressure	
	Overburden Leak Path Models	Assessment of hypothetical leak paths and rates into shallow aquifers	Legacy well properties and Quest well properties at regional scale	Leak features (legacy wells, own injector wells or faults) pressure and plum distribution, leak path properties (porosity, perm)	Arrival times, leak rates and gechemical reactions in formationa above the storage complex.	
	Analytical Point Source Model	BCS leakage into Winnepegosis **(MMV)**	Winnepegosis formation properties	DTS Sensitivity	Detectable leakage rate and radial concentration decay	
	Time Laps Seismic Modeling Study	Feasibility was confirmed in Gen3, additional modeling for conformance benchmarking.	**Radway calibrated** geophysical properties, CO_2 plumes from sector model study	CO_2 saturation as function of time	Seismic detection thresholds as function of CO_2 net-thickness and noise level	
	Well Bore Stability Models	Stress field change and impact on completion, cement integrity and wellbore stability.	**Radway** formation properties, temperature distribution	Thermal expansion coefficient, BHP	Stress field change and associated fracture pressure reduction	Estimated reduction in BHP constraint (28 MPa) with a low case of 24 MPa due to reservoir cooling.

APPENDIX 3. RISK REGISTER

CRITICAL

ID	Name	Description
R-4354	QUEST: Regulatory framework immature => approvals delayed => Schedule Delay (pre-FID)	CAUSE: Regulatory approvals for operating permits of the capture, pipeline, wells and storage components are critical pre-requisites to the implementation of Quest. However, the regulatory approvals framework is immature wrt CCS. The absence of regulatory "directives" for CCS projects, i.e. applicability of D65, may caused significant impact to regulatory timeline. Other significant impact may be the requirement for Federal & Provincial EA. Other cause is the the absence of pore space regulations, which is of particular concern (and is treated under a separe risk R-4340 "Secured Required Pore Space"). CONDITION: Approval cycles may increase in duration. This risk covers impact for unclear directives and uncertain Environmental requirement & approval timeline. CONSEQUENCE: Delay in Project Schedule >6months
R-4484	QUEST: Stakeholder Objections & Intervention	Used as R-1 in SRA Negative perception of CO2 sequestration projects by stakeholders => Stakeholder Objections & Interventions => impact on regulatory activities (schedule pre-FID) Cause: Late SH engagement, misleading and/or conflicting information, lack of knowledge and understanding of CCS, CO2 toxicity, etc Event: Stake holder-landowners objection to Quest, Stakeholder opposition to the project develops at one or more levels Consequence: o Project schedule is threatened as permit application processes lengthen o Delays or stop Internal decision to proceeed o Higher cost due to changes to FA CCS premises (pore space, injection sites & pipeline routing, no-go for the project) o Major costs increases are required to appease unsatisfied stakeholders
R-4338	QUEST: Cost Escalation threatens NPV =0 aspiration	Cause: The Funding Agreement with the GoA will be premised on cost estimates and market views developed more than three years ahead of FID. The absence of upside exposure results in asymmetric risks. Higher cost estimates challenge the ability to negotiate an agreement. Event: Higher costs at FID and a dim view on CO2 prices preclude a positive decision. Higher operating costs (not balanced by revenues, see #21) challenge the operating phase of the project. Consequence: o Negative exposure to market o Potential uncertainty to FID, beyond o Stop project
R-4343	QUEST: Unchecked Scotford Site Integration	Site integration activities are key to the success of the venture, through the design, construction and s/up phases to address the brownfield project activities and the impact on the reliability of HMU operation. Risk event :Decisions taken on Scorford or project without chercking the mutual impact => Umitigated consequences are: 1. Impact on Scotford Production; 2. Project delay or cost increases as integration is done at a later date with less flexibility or options
R-4355	QUEST: Significant international campaign against oilsands and CCS	Significant international campaign against CCS, considered an enabler of Oil Sands which may have opposition initiatives=> Significant International Opposition to CCS projects, with international & local protest=>may influence regulator and local stakeholders, or may result in disruption of Scotford base operation=>Quest schedule delays (to FID) & Reputation damage. The Impact for this risk is assessed against International opposition -only, and mitigation plans to manage and International NGOs campaign. The higher impact on Schedule that may be caused by this risk in delaying regulatory approval process (e.g. by forcing a Joint panel hearing, or by influencing local stake holder) will be covered under R-4484 (Stakeholder Objection and Interventions)

SEVERE

ID	Name	Description
R-4026	QUEST: Uncertainty with Scotford turnaround (may occur earlier than plan)	Used as R-19 in SRA. Uncertainty with Scotford shutdowns (may occur before 2014) =>engineering or materials may not be available in time so tie-ins for Quest are not completed =>extension to the planned S/D or project will have to wait for next window Causes: Scotford baseplant shutdown date may move to earlier 2014 due to operational/maintenance needs, and expansion 1 may move earlier than 2013 (i.e. 2012) Risk Event: Shutdown dates moves earlier and as a result either engineering or materials are no available in time for 2014 so tie-ins for Quest are not completed. Consequence: Missing the S/D window would results in loss opportunity for HMU Tie-Ins / Fan Replacement / Burner Replacemen. This could either cause an extension to the planned S/D ($$$ or production impact) or project will have to wait for next opportunity to tie in. This would result in major project start up delay and result in reputational issues and lost of (part of) GoA funding
R-4177	QUEST: Injection induced stress reactivates a fault	CAUSE: Existing faults are reactivated as reservoir pressure or thermal stresses may exceed fault strength RISK EVENT: Pressure/CO2 migration through primary (MCS) and ultimate seals (Lotsberg salts) resulting in loss of containment. CONSEQUENCE: More extensive MMV measures may be required, injection may need to be cut back or redistributed over potentially additional wells and CO2 credits could be lost as uncontained volumes of CO2 would incur penalties. If loss of containment remains undetected contamination of potable water zones and leak to surface may eventually result which could endanger public health and safety, cause environmental damage, legal action, and national reputation loss.
R-4339	QUEST: Timely Demonstration of Storage Feasibility	CAUSE: Fast track appraisal & subsurface studies, early definition CCS project description with immature subsurface understanding RISK EVENT: Unable to demonstrate storage feasibility (Containment, Injectivity & Capacity) internally or, to Regulatory board and address Government and public concerns. Inappropriate porespace and injection site selection. CONSEQUENCE: Inability to convince stakeholders of the long-term performance of the storage system could result in the following consequences: 1. Inaccurate media reports or misinterpreted information 2. Delays in; i) Regulatory approval, ii) FID and iii) achieving sustained injection capacity 3. Severe public opposition, 4. Government refusal to accept long term liability of CO2 at project completion if containment can not be demonstrated (also captured in R4342 "Inability to Demsontrate Conformance"), 5. Project costs increase as alternate storage site is selected post injection.
R-4340	QUEST: Secure Required Pore Space	Cause: Unable to secure timely the required pore space for Quest CCS project Events: Pore Space taken by another user, or utilized by a drilling venture, or late approval Consequences: 1.Delay Appraisal campaign & other regulatory approvals 2.Additional costs to locate and acquire alternate space 3.Unable to manage porespace and demostrate containment if conflicting schemes 4. Project delayed or cancelled at FID due to mandate not met
R-4518	QUEST: Appraisal Information insufficient to support FID (insufficient to reduce Subsurface Uncertainties)	Umbrella risk to capture all unexpected appraisal results from the 3rd well, seismic, HRAM or studies that push the most likely subsurface scenario outside the current range and cause a major change in the development design concept (change of site, more wells, higher pressures, etc) and significant delay due to re-engineering and re-work of the regulatory process. Subrisks included here are: - Well failing to meet success criteria (seals below Winnipegosis<2, Upper Lotsberg<40m, kh<600 mD m, h*phi*N/G< 3.0 m) requiring a 4th appraisal well and pushing out the project timeline (linked to risks 4135 on Inj. and 4166 on Cap.). - Seismic showing heavy faulting with high likelihood of compartmentilisation causing an increase in development wells and potentially higher injection pressures (link to risk 4166 on Storage Capacity). - 3D seismic survey too small to identify sufficient development well locations due to abundance of small faults to be avoided - Studies (Gen3 modelling) showing that the low case scenario is not robust for a 10 well development scenario.

ID	Name	Description
R-4689	QUEST: Expansion 1 & Base Plan Turnaround later than planned	Causes: Business pushes Exp 1 T/A to 2014 (later than expected), or Business pushes Base Plant T/A to 2015 (later than expected) Consequences: Project misses T/A opportunity and cannot come on stream by on stream by December 2015, or by 2017 Increased TIC Need to schedule Quest-specific outage Reduced government funding Reputation impact Impact of increased expense on NPV HSE and cost risks with having to modify execution plan
R-4690	QUEST: Operations Turnaround strategy or scope affects Quest turnaround plans	Caused by changes in the Operations T/A execution strategy and scope affecting QUEST T/A current plan and scope. Examples are: 1. Retubing of furnace takes the time it was going to take to install the new Low Nox burners) 2. Discovering unplanned work of a higher priority during T/A's (pushes window of opportunity out 3. Business splits Base Plant T/A to 2014 and 2016 and therefore cannot do flare and utilities tie-ins >delays Quest tie-ins
R-4691	QUEST: Project team is not ready for Turnaround	Quest team is not ready for TA as per base case plan PEPPER: Project T/A work definition is delayed (Exp 1 T/A now comes too early)
R-4732	QUEST: 3rd Gen Modules - Modularization strategy and plan developed too late	Potential causes are: >Poor implementation strategy developed during FEED Consequences: >Cost saving opportunity lost >Module design fails to achieve intended work shift from site >Modules are incomplete, or not current to latest design, upon arrival >Modules arrive late or in the wrong sequence
R-4788	QUEST : Unrecognised Errors in Economic Analysis and Evaluation	CAUSE: Incorrect economic analysis & evaluation Events:Poor economic performance, unable to meet mandate of NPV-0 at FID Consequence: Project cancellation
R-4962	Lack preservation after air drying / not clear handover process to operations	"Cause: Inadequate preservation causes corrison. Event: Loss of containment. Consequence: Line failure/fail stratup/injection loss/reputation impact."
R-4497	QUEST: Novel applications of compressor => Start-up/ ramp-up issues (e.g., seal leak of dense phase CO2) may be discovered => Schedule (to OS) delay to fix the issue	Used as R-29 in SRA
R-4498	QUEST: Unable to meet commercial Operations test criteria due to start up constraints	Used as R-30 in SRA Setup of Sustainable Operations/ injection criteria by government => Issues to demonstrate required injection rates during startup may be discovered.
R-4724	QUEST: 3rd Gen Modules - Modules delivered late and/or in wrong sequence=> due to poor Logistics	Poor transportation planning and execution from mods yards to the site. (Ex: Logistics - Haven't arranged for power lines to be raised, etc.) >Module incidents during transportation >Insufficient laydown space >Lack of recovery plan-logistics to onsite movement of modules
R-4731	QUEST: 3rd Gen Modules - Modules delivered late and/or in wrong sequence due Late materials to mods yards	

ID	Name	Description
R-4750	QUEST: Fabricators' lack of understanding of QA/QC requirements or other issues => 3rd Gen Modules - Modules may be Incomplete at Shipment => Impact on schedule (delays) and cost (indirects and rework)	3rd Gen Modules Incomplete at Shipment due fabricator lack of QAQC or other issues Causes: >Fabricator performance (quality and schedule), poor quality record keeping; size, weight and center of gravity of completed modular deviated from transportation constraints >Fabricator goes out of business
R-4751	QUEST: Incomplete and/or delays in Instrumentation, Electrical & EHT materials deliveries => 3rd Gen Modules - Modules may be Delivered late => Impact on schedule (delays) and cost (indirects)	Potentital causes are: >Electrical material unavailable >EHT material unavailable >Electrical Equipment, Instrument and DCS/SIS field components unavailable >E&I requirements not identified in model review >Responsibility for procurement of material is not clear between EPC and fabricator >Definition of what E&I is needed for 3G is not clear >E&I engineering incomplete or inaccurate Consequences: >Rework in the field >Delay in MC and startup (sustained opeations date) >Modules arrive at site out of sequence >Temporary facilities cannot support modules being delivered to field before they're ready >Subcontractor for completing modules does not meet pre-qualification for site safety requirements (in the event that incomplete modules arrive at site)
R-4752	QUEST: Incomplete and/or delays in Steel & Piping materials deliveries => 3rd Gen Modules - Modules may be delivered late => Impact on schedule (delays) and cost (indirects)	Causes: >Piping material requirements and specifications not understood. >Single release of piping material for purchase >Material shortages by isometric >No Management of fabrication processes >Low cost country sourcing >Logistics of shipping from "mismatched" locations (e.g. Steel fabricated in one place, piping fabricated in another) Consequences: >Rework in the field >Delay in MC and startup (sustained opeations date) >Modules arrive at site out of sequence >Temporary facilities cannot support modules being delivered to field before they're ready >Subcontractor for completing modules does not meet pre-qualification for site safety requirements (in the event that incomplete modules arrive at site)
R-4957	Shortage of skilled labour	Cause: Overheated market. Event: Shortage of qualified labour. Consequence: schedule delay, cost overrun & potential HSE isssues.
R-4040	QUEST: Local and International Market Changes=> Project CAPEX post-2012 FID Higher than Expected	Local market changes and uncertainty due to > to higher local and international activity, or rise in oil prices creating a period of high activity with concurrent projects , or consolidation of the market place>this could result in Higher CAPEX.
R-4163	QUEST: Unexpected CO2 plume migration outside of notification area	CAUSE: Non conformance as plume travels outside the notification area (49 sections per injector) due to unexpected local topography, heterogeneity, basement fractures or reduced residual and capillary trapping RISK EVENT: Plume migrates outside notification area (loss of conformance) CONSEQUENCE: More extensive MMV measures such as additional surface seismic may be required, injection may need to be cut back or redistributed over potentially additional wells to limit plume sizes. Area of notification (49 sections) may have to be increased to match plume distribution, or additional wells maybe required to stay within notifcation area. Liability period after injection period may need to be extended, reputation loss with the regulator will result if plume migration can not be predicted with reasonable range.

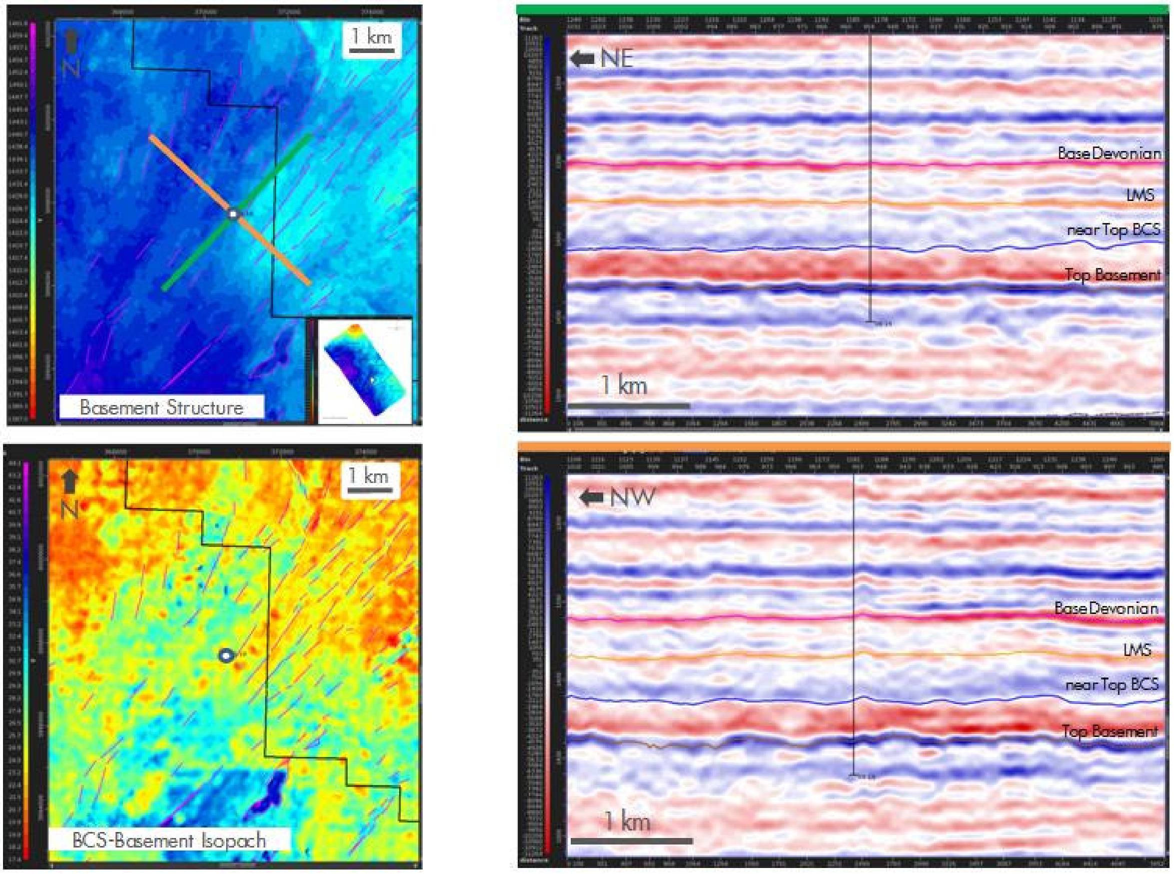
ID	Name	Description
R-4503	QUEST: Inability to differentiate contamination from external sources from project emissions	CAUSE: Insufficient, incorrect or late base line data for MMV planning and Start-up, Sensitive domains cannot be characterised (too much natural variability), Detection thresholds and resolution of available MMV technologies are inadequate to identify If Quest is the source of contamination or quantify the volume of CO2 no longer contained. RISK EVENT: Contamination of Geo-, Hydro, Bio- or Atmosphere, either pre-existing or from external sources (mines, landfills, agricultural or other industry) can not be differentiated from project emissions. CONSEQUENCES: Shell and the JV could become liable for a wide range of contamination issues in and around the pore space AOI that are not caused by Quest, large reputational damage and loss of public acceptance of the project, potential early termination of the project.
R-4588	QUEST:Failure to meet FA Performace criteria due to CO2 Feed Availability	Unable to reach system capacity performance criteria of 10.8 Mtons /10 years as defined in the FA =>CO2 emissions (feed) for capturing may be lower than currently used in the FA (AOSP reliability)=> ,lose funding, impacts revenue.
R-4948	Project Controls for Construction Progress	CAUSE: "Rules of credit" for construction progress may not be defined correctly. EVENT: Construction progress may be over-reported. CONSEQUENCE: Schedule impact.
R-4964	Pigs get stuck in line because of CO2 is a solvent that damage pig - line need to review with pigging company + smart pig conpany that we can pig the line - include in IRP	"Cause: Swelling of the elastimer and burning up of the cups. Event: Pig stuck in the line. Consequence: Loss of flow."
R-4342	QUEST: Inability to Demonstrate Conformance	CAUSE: Handover issues may occur during de-commissioning and Government and/or other stakeholders may not be convinced of the MMV program's integrity and validity of results. RISK/EVENT: Inability to Demonstrate Conformance (not meet performance criteria) and Government does not take long-term liability of the CO2 storage site at site closure CONSEQUENCES: Dispute with GoA, long period of performance verification, delayed hand-over of liability, extra costs and reputation damage.
R-4347	QUEST: Long-term liability for storage site (inc. Performance Critera) not agreed with Government	CAUSES - No established regulatory framework for performance criteria or internal consensus on what would be acceptable. CCS act contains provision for long term liability but detailed regulations are required to be passed before a clear picture emerges. RISK EVENT -Unable to reach an agreement with the government that they will in principle hold the long-term liability associated with CO2 storage subject to an agreed set of performance criteria for liability handover before FID. CONSEQUENCES=> Regulator does not grant necessary regulatory approvals, Stakeholders create delays through the hearing process, lack of public acceptance of the project causes reputation damage and project delays. FID decision may be delayed or impossible.
R-4431	QUEST: Unfavourable GHG legislation causes credits value to fall below premise	Cause: Unfavourable GHG Legislation/Credit value. GHG Legislation is an emerging field with many gaps and uncertainties. Sale of CO2 credits represents the only revenue stream for Quest (apart from Government Funding and any future EOR sales). Event: The value of Quest might be reduced if e.g. CCS credits were not tradeable at fair market value as a result of restrictive/ additional GHG regulations/legislation. CO2 Pricing/credits or volume may fall significantly below premise, or & actual prices of CO2 are low during operation Consequence: impairing NPV, Revenue loss
R-4495	QUEST: QA/QC-related issues during production & transportation of major equipment => Equipment might be damaged or out-of-spec => schedule impact due to re-work	Used as R-31 in SRA
R-4566	QUEST: Quest capture application- Scope of review expands to include existing operations	The regulatory application for the Quest capture facility is an amendment to to the existing Scotford Upgrader approvals. There is a risk this application to amend approvals may result in the scope of review expanding to include all aspects of existing Scotford operations. Could result in costs to Scotford and schedule delay as scope of Quest regulatory expands.
R-4722	QUEST: Incomplete definition of path of construction and/or module RAS dates => 3rd Gen Modules may be delivered late and/or in wrong sequence => Impact on schedule (delays) and cost (indirects)	QUEST: 3rd Gen Modules - Modules delivered late and/or in wrong sequence=> due to undefined path of construction and module RAS dates=>impacting schedule and cost

ID	Name	Description
R-4725	QUEST: Winter shipping window not matching plan => 3rd Gen Modules - Modules may be delivered late and/or in wrong sequence => Impact on schedule (delays) and cost (indirects)	
R-4726	QUEST: Lack of full integration with fabricator on engineering, procurement and construction => 3rd Gen Modules - Modules may be delivered late and/or in wrong sequence => Impact on schedule and cost	Fabricator not integrated into Engineering Procurement Fabrication Construction (EPFC) execution plan; or, Engineering and Procurement sequence to support the fabrication shops is not aligned (Ex: Strategy around material interfaces, etc.)
R-4730	QUEST: 3rd Gen Modules - Modules delivered late and/or in wrong sequence due to late vendor data	Causes: >due to late approval of vendor data; or, >due to scope and/or execution changes cause rework and schedule delays / cost increases
R-4958	Shortage of local infrastructure	"Cause: Demand on local infrastructure to accommodate construction crews. Event: Shortage of accomodations. Consequence: schedule, cost, HSE impacts"
R-4041	QUEST: Uncertainty in Labour Availability in Edmonton due to Multiple Projects post-2012 => higher than expected demand in qualified labour => Higher Costs	Shop Capacity Constraints due to lack of Labour Schedule and Premium may need to be paid to get skilled labour and may need to import skilled workers Note: Craft labour rates and engineering are not taken in account by this risk but taken into general uncertainites of base estimate
R-4350	QUEST: Insufficient Commercial Options to Mitigate poor economic performance of the base plan	CAUSE: Insufficient commercial opportunities Events: Inability to mitigate poor economic performance of the base plan , unable to meet mandate of NPV=0 at FID Consequence: Project cancellation
R-4749	QUEST: Poor QA/QC and/or Engineering definition of Module Work Packages (MWPs) => 3rd Gen Modules - Modules may be Incomplete at Shipment => Impact on schedule (delays) and cost (indirects and field work)	3rd Gen Modules Incomplete at Shipment=>Due to inadequate integration of engineering and procuremnet with module fabrication Specific causes: >Lack of Planning for drawing and material availability before assembly starts. >No identification or tracking of Drawing and material >Late purchase and delivery of materials and equipment >Engineering and Procurement sequence to support the fabrication shops is not aligned (Ex: Strategy around material interfaces, etc.) >Untimely delivery of engineering deliverables to the fab shop (isometrics, etc.) >Final materials (procurement) do not match final engineering deliverables >The engineering drawings and materials are not adequately tagged by module >Poor decision to ship imcomplete modules ..... >late vendor data >late approval of vendor data
R-4904	QUEST: 3G Stakeholder Alignment	Cause: Lack of alignment among stakeholders (PMT, SMEs, O&M, Fluor, fabricators, vendors) around 3G engineering and execution strategy Risk Event: May fail to reach agreement on construction and pre-commissioning capability of contractors and commercial tactics needed to support 3G execution Consequence: Expected TIC savings are not realized
R-4905	QUEST: Construction before engineering complete	Cause: Engineering delayed, but there is pressure to mobilize to the field per the original schedule. Risk Event: Project may begin construction with less engineering complete than planned. Consequence: "Engineering in the field means more rework. Cost and schedule impact."

ID	Name	Description
R-4970	Applying too late for crossing agreements	"Cause: Lack of planning Event: Delay in crossing agreement. Consequence: Delay in pipelines and cost of workarounds"
R-4971	"unknown UG lines - abandoned lines with product??	"Cause: Inadequate data from surveyors/Alberta First Call, failure to locate. Event: Line strike Consequence: Loss of containment/fatality "

APPENDIX 4. INJECTION WELL SITE SELECTION

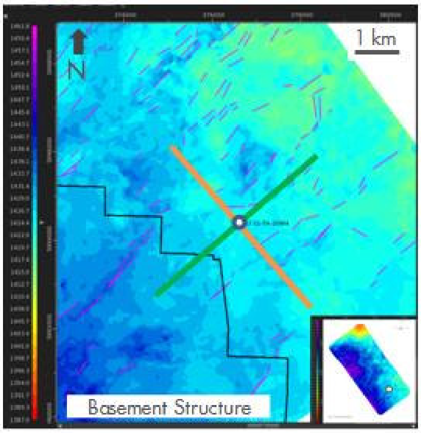
Well: 08-19-59-20W4 (Radway 8-19)

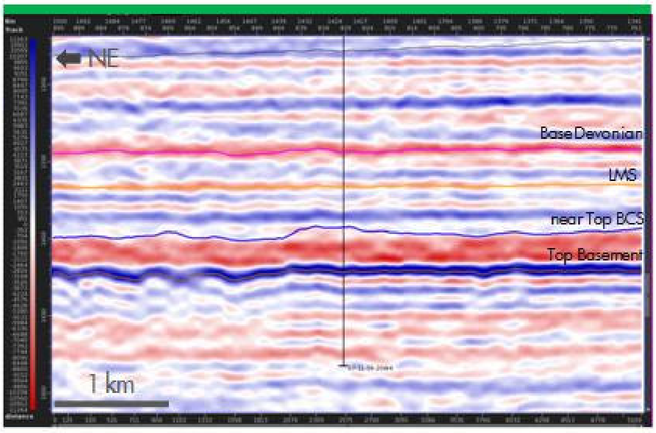


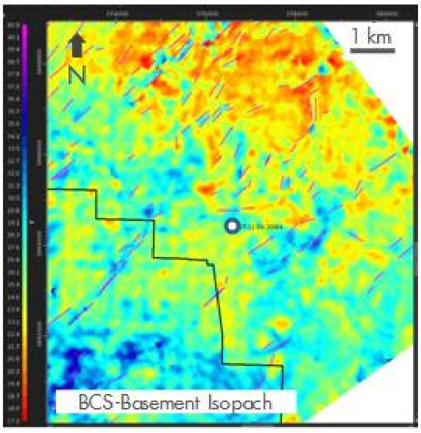
Well information

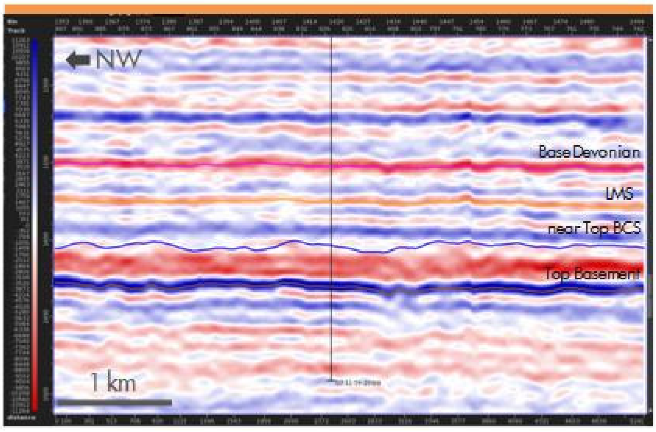
- Well location (X,Y): 370,705.5, 5,997,747.4
  - Coordinates are in NAD27 UTM meters Zone 12N
- Radway 8-19 BCS isochron: 25 ms (~45 m @ Vint = 3600 m/s)
- Distance to survey edges:
  - NE: 7.1 km
  - SE: 10.6 km
  - NW: 18.8 km
  - SW: 6.6 km
- Approximate distance to pipeline: 1.1 km

Proposed Well: 07-11-59-20W4 (Injector 2)





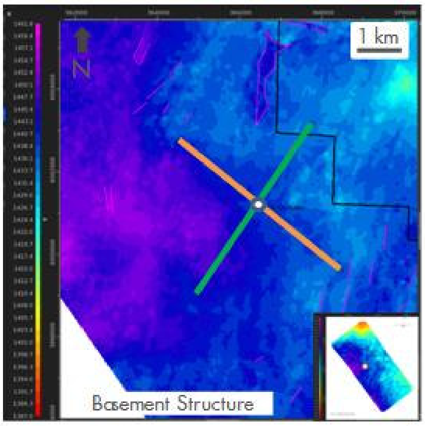


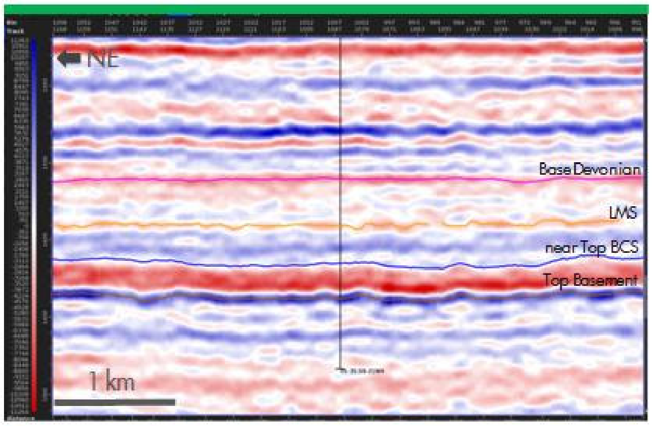


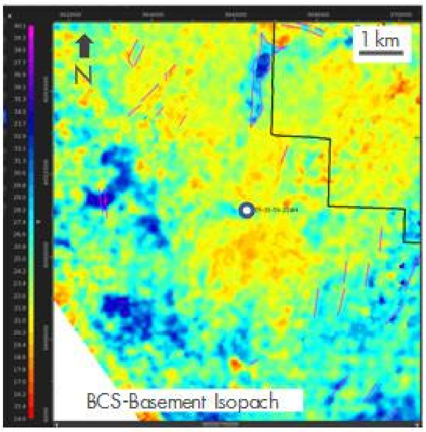
Well information

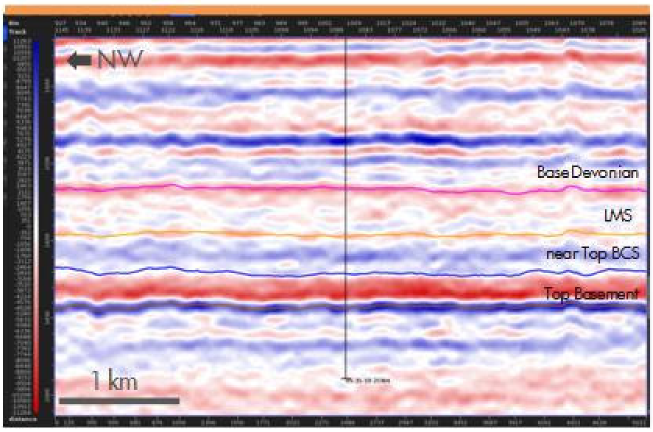
- Well location (X,Y): 376,674.1, 5,994,416.7
  - Coordinates are in NAD27 UTM meters Zone 12N
- Radway 8-19 BCS isochron: 25 ms (~45 m @ Vint = 3600 m/s)
- 07-11-59-20W4 BCS isochron: 29 ms (~52 m @ Vint = 3600 m/s)
- Distance to survey edges:
  - NE: 4.2 km
  - SE: 4.4 km
  - NW: 25.1 km
  - SW: 9.4 km
  - Approximate distance to pipeline: 1.2 km

Proposed Well: 5-35-59-21W4 (Injector 3)





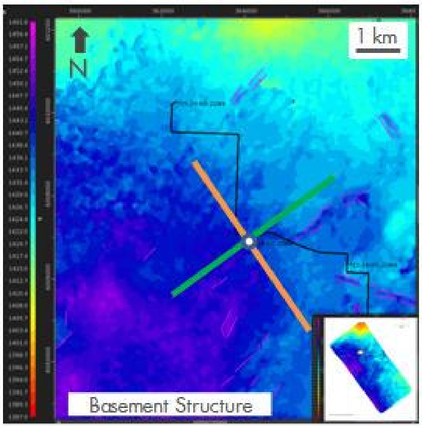


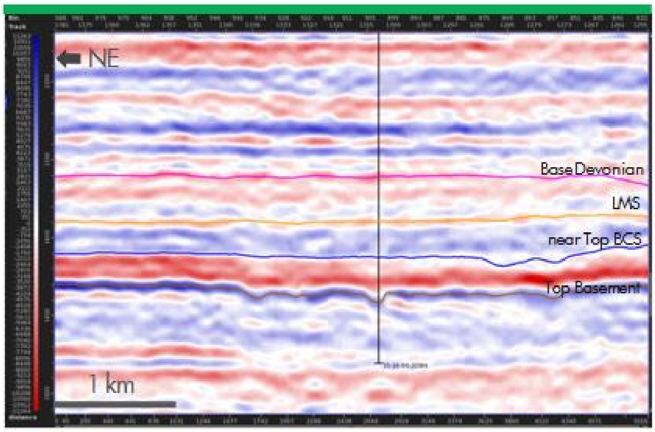


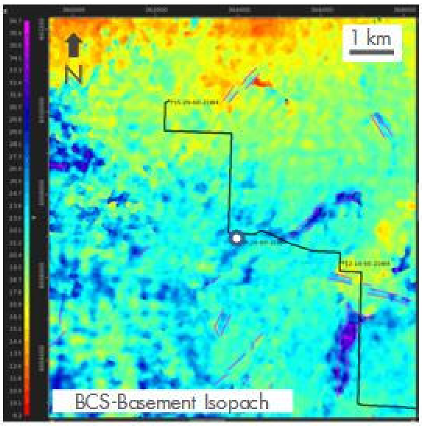
Well information

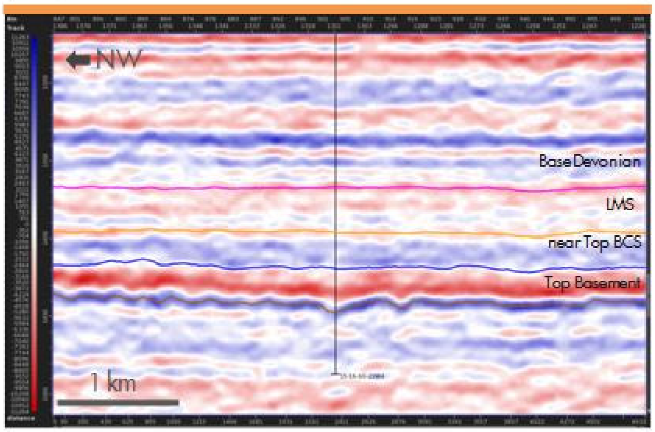
- Well location (X,Y): 366,423.3, 6,001,156.9
  - Coordinates are in NAD27 UTM meters Zone 12N
- Radway 8-19 BCS isochron: 25 ms (~45 m @ Vint = 3600 m/s)
- 5-35-59-21W4 BCS isochron: 23 ms (~41 m @ Vint = 3600 m/s)
- Distance to survey edges:
  - NE: 8.3 km
  - SE: 16.0 km
  - NW: 13.5 km
  - SW: 5.2 km
- Approximate distance to pipeline: 2.1 km

Proposed Well: 15-16-60-21W4 (Injector 4)





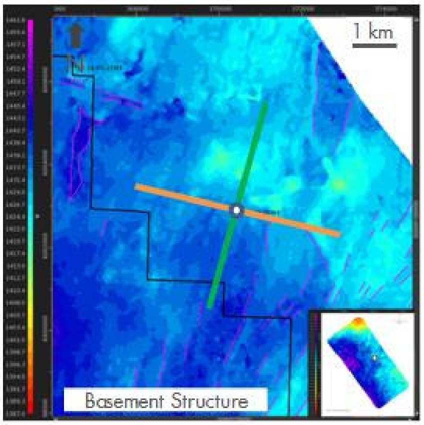


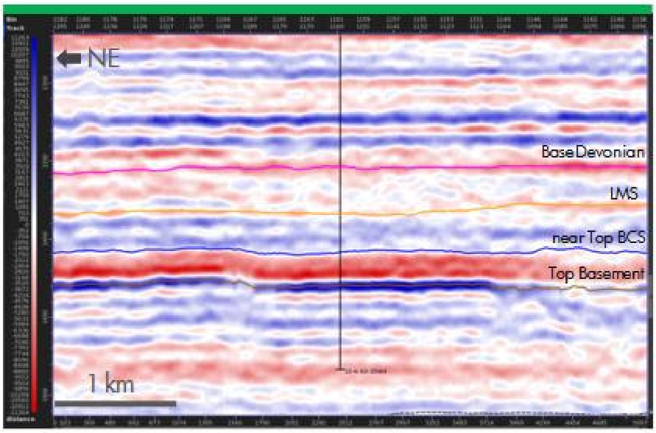


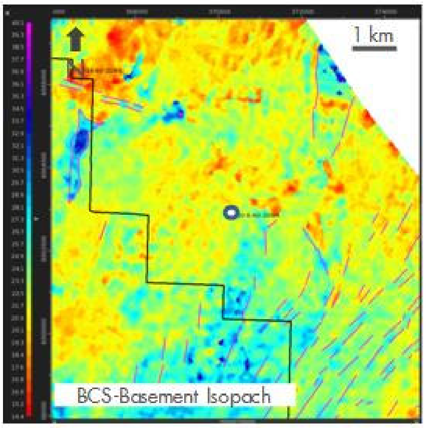
Well information

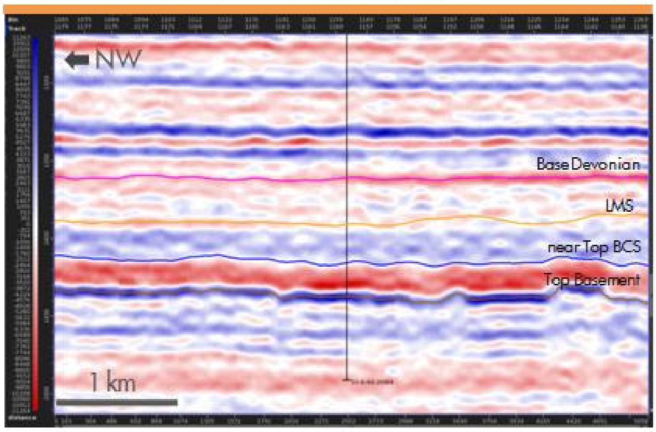
- Well location (X,Y): 364,049.0, 6,006,879.0
  - Coordinates are in NAD27 UTM meters Zone 12N
- Radway 8-19 BCS isochron: 25 ms (~45 m @ Vint = 3600 m/s)
- 15-16-60-21W4 BCS isochron: 28 ms (~50 m @ Vint = 3600 m/s)
- Distance to survey edges:
  - NE: 7.1 km
  - SE: 21.9 km
  - NW: 7.5 km
  - SW: 6.6 km
- Approximate distance to pipeline: 0.215 km

Proposed Well: 10-06-60-20W4 (Injector 5)





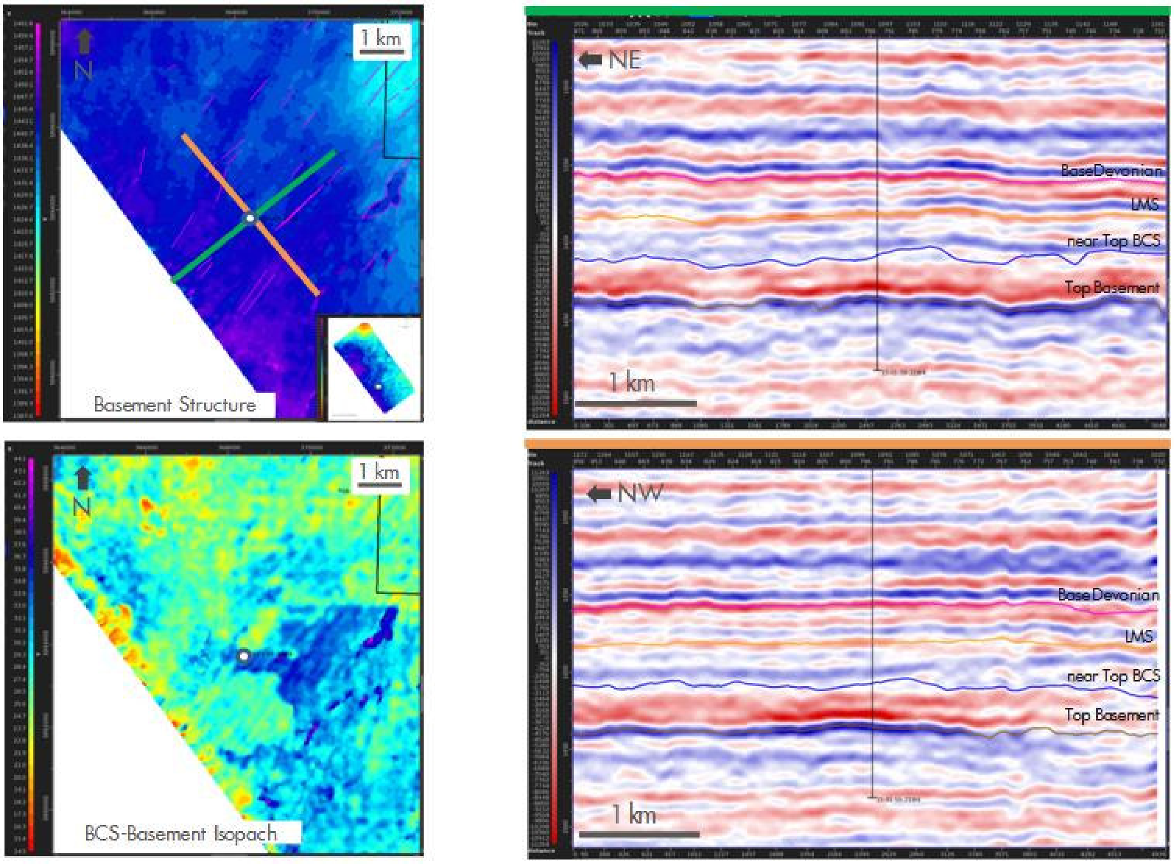




Well information

- Well location (X,Y): 370,401.1, 6,002,873.8
  - Coordinates are in NAD27 UTM meters Zone 12N
- Radway 8-19 BCS isochron: 25 ms (~45 m @ Vint = 3600 m/s)
- 10-06-60-20W4 BCS isochron: 22 ms (~40 m @ Vint = 3600 m/s)
- Distance to survey edges:
  - NE: 4.1 km
  - SE: 14.9 km
  - NW: 14.5 km
  - SW: 9.4 km
- Approximate distance to pipeline: 2.1 km

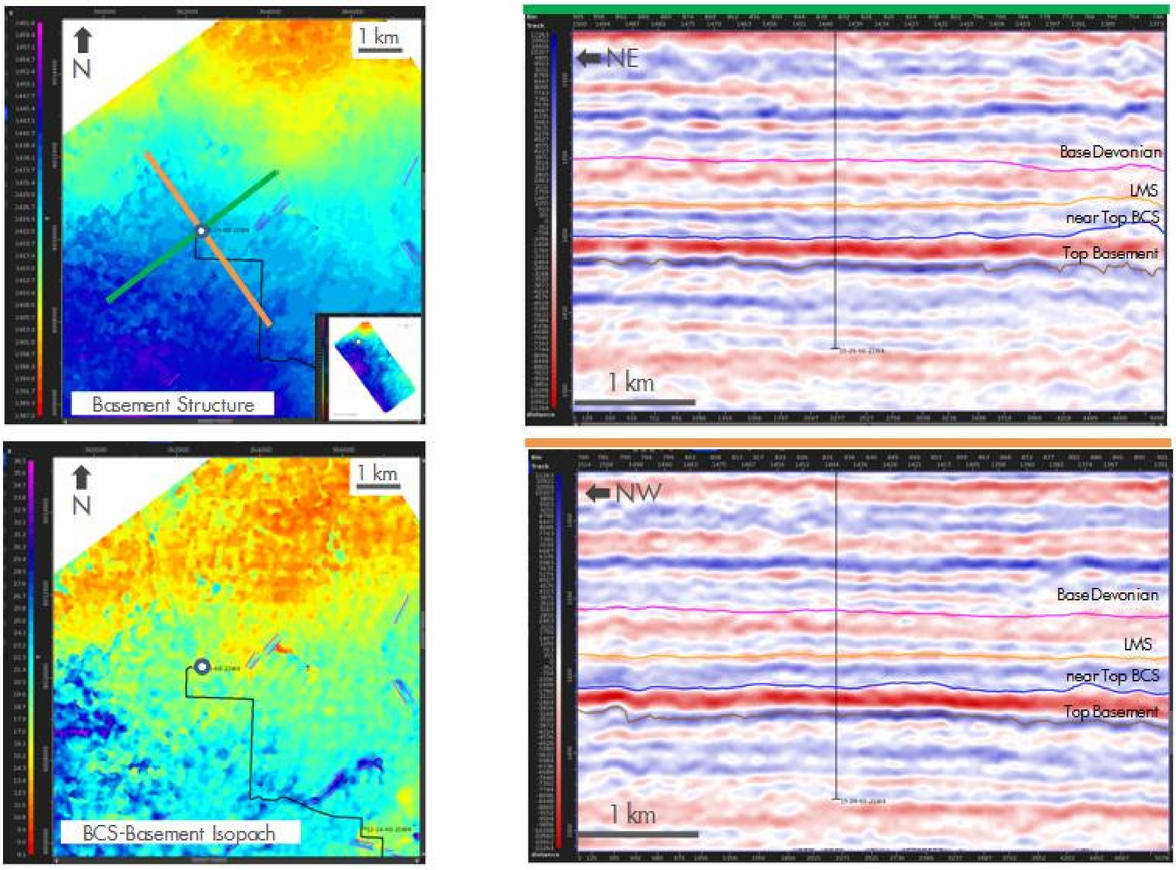
Proposed Well: 15-01-59-21W4 (Injector 6)



Well information

- Well location (X,Y): 368,542.6, 5,993,780.3
  - Coordinates are in NAD27 UTM meters Zone 12N
- Radway 8-19 BCS isochron: 25 ms (~45 m @ Vint = 3600 m/s)
- 15-01-59-21W4 BCS isochron: 28 ms (~ 50 m @ Vint = 3600 m/s)
- Distance to survey edges:
  - NE: 11.2 km
  - SE: 8.8 km
  - NW: 20.6 km
  - SW: 2.6 km
- Approximate distance to pipeline: 4.7 km (on right angles)

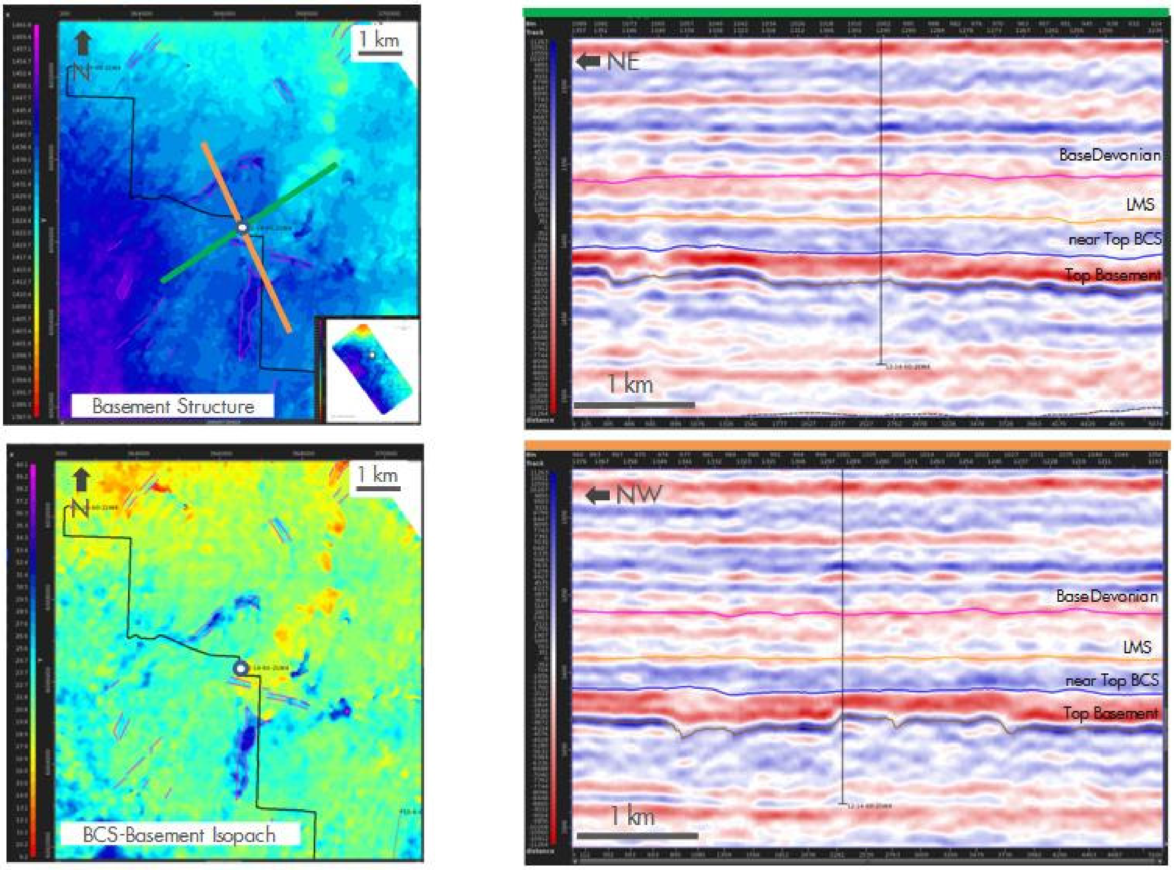
Proposed Well: 15-29-60-21W4 (Injector 7)



Well information

- Well location (X,Y): 362,408.9, 6,010,249.0
  - Coordinates are in NAD27 UTM meters Zone 12N
- Radway 8-19 BCS isochron: 25 ms (~45 m @ Vint = 3600 m/s)
- 15-29-60-21W4 BCS isochron: 17 ms (~30 m @ Vint = 3600 m/s)
- Distance to survey edges:
  - NE: 6.5 km
  - SE: 25.6 km
  - NW: 3.8 km
  - SW: 7.8 km
- Approximate distance to pipeline: 0.070 km

Proposed Well: 12-14-60-21W4 (Injector 8)



Well information

- Well location (X,Y): 366,539.4, 6,006,367.4
  - Coordinates are in NAD27 UTM meters Zone 12N
- Radway 8-19 BCS isochron: 25 ms (~45 m @ Vint = 3600 m/s)
- 12-14-60-21W4 BCS isochron: 17 ms (~30 m @ Vint = 3600 m/s)
- Distance to survey edges:
  - NE: 5.2 km
  - SE: 20.0 km
  - NW: 9.4 km
  - SW: 8.2 km
- Approximate distance to pipeline: 0.100 km

APPENDIX 5. EVALUATION OF HYDRATE RISK IN THE PIPELINE AND UPDATED DEHYDRATATION REQUIREMENT

1. Summary

The minimum TEG unit performance was based in the BfD on a maximum of 6 lbs/MMscf of water in the injected CO2 throughout the year. A thorough analysis of the risk of hydrate formation in the system highlighted that during spring, the pipeline could potentially operate within the hydrate formation zone. As this is deemed not acceptable because of the consequences on system availability and operational safety, it is proposed to update the requirement of dehydratation to 4 lbs/MMscf in the winter (below 22 degC air temperature) and 6 lbs/MMscf in the summer (between 22 and 34 degC air temperature).

The current design of the TEG unit can meet these updated requirements with no impact on CAPEX and limited impact on OPEX.

It is therefore recommended to include the expected winter performance of the TEG unit as an actual requirement, in order to eliminate the risk of hydrate formation in the pipeline in all cases.

2. Background

Injecting CO2 with minimum water content is a requirement to ensure system integrity. Although corrosion is an important damage mechanism, hydrate formation induces a more stringent requirement on the dehydration of the CO2 stream. The most risky period for hydrate formation in the pipeline is spring for the following reasons:

- The CO2 in the ~80km pipeline will equilibrate with the ground temperature, which is still cold in spring (~0 degC)
- The hydrate formation temperature will start to rise as the warmer air temperature makes the TEG unit performance slightly poorer than in winter

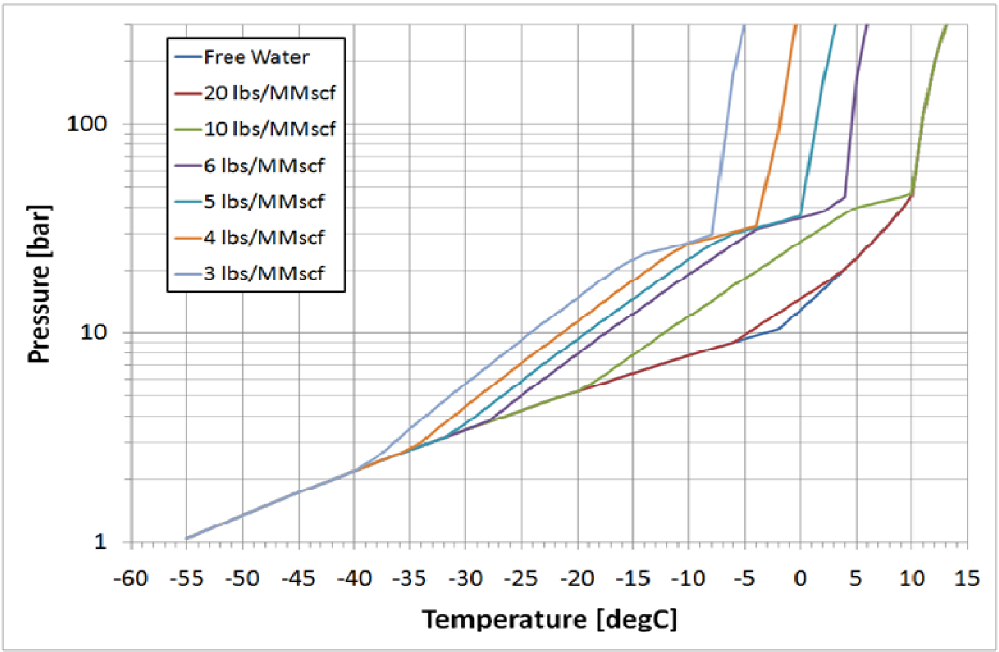
Therefore, there is a need to assess whether spring still enable to operate the pipeline outside of the hydrate formation zone in all cases.

3. Technical discussion

This section discusses the different assumptions used to quantify the hydrate risk in the pipeline during spring.

3.1. Hydrate formation temperature

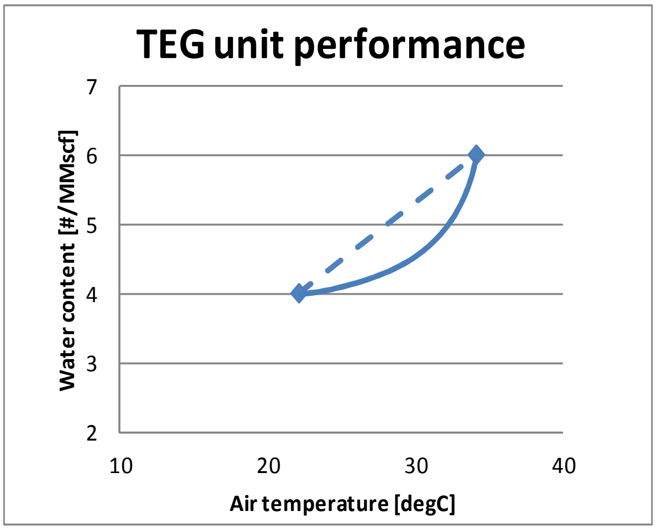
The following graph presents the hydrate formation temperature for different water content (from Quest CCS Prospect: Flow Assurance for System Selection, SGS Houston, November 2011).



As it can be seen, the hydrate formation temperature is slightly higher at the expected maximum pipeline operating pressure (14MPa). Therefore, for a matter of conservatism, the hydrate formation temperatures for a given water content will be considered at 14 MPa in the rest of the analysis.

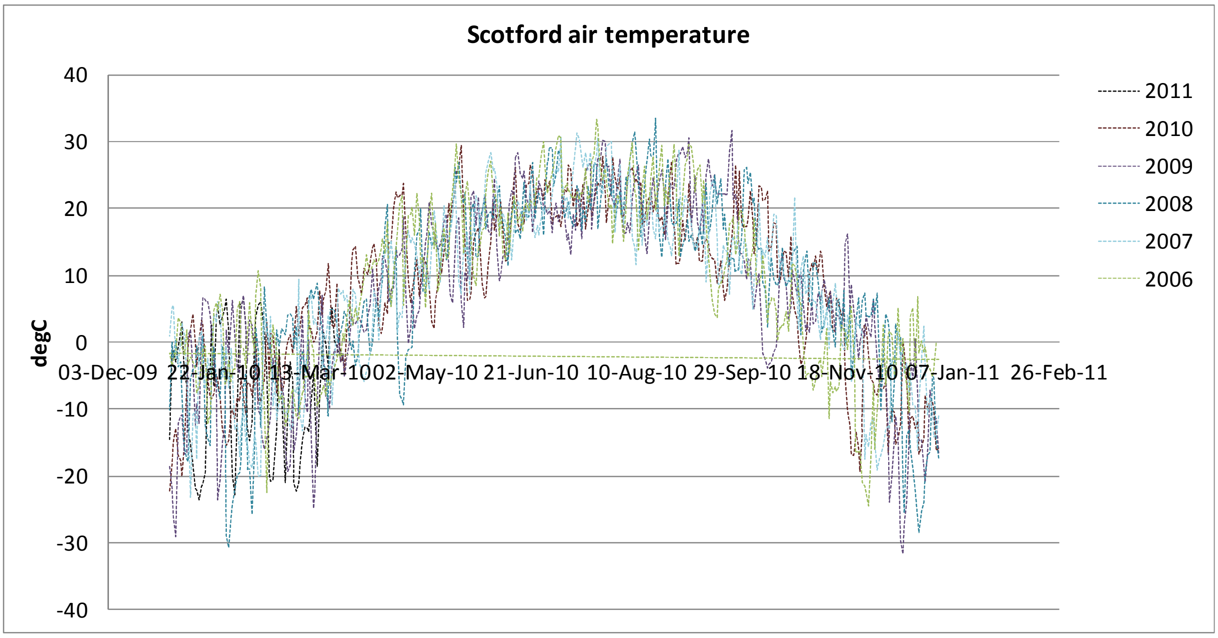
3.2. TEG unit performance

Discussion with Fluor highlighted that, although the original TEG unit design requirement is based on guaranteeing 6 lbs/MMscf of water in the injected CO_2 throughout the year, the TEG unit would actually perform better in the winter, due to lower air temperature. The schematic on the right hand side shows the expected TEG unit performance vs. air temperature (solid line). For a matter of conservatism however, the TEG unit performance will be assumed linear in the rest of this document (dotted line).



3.3. Air temperature

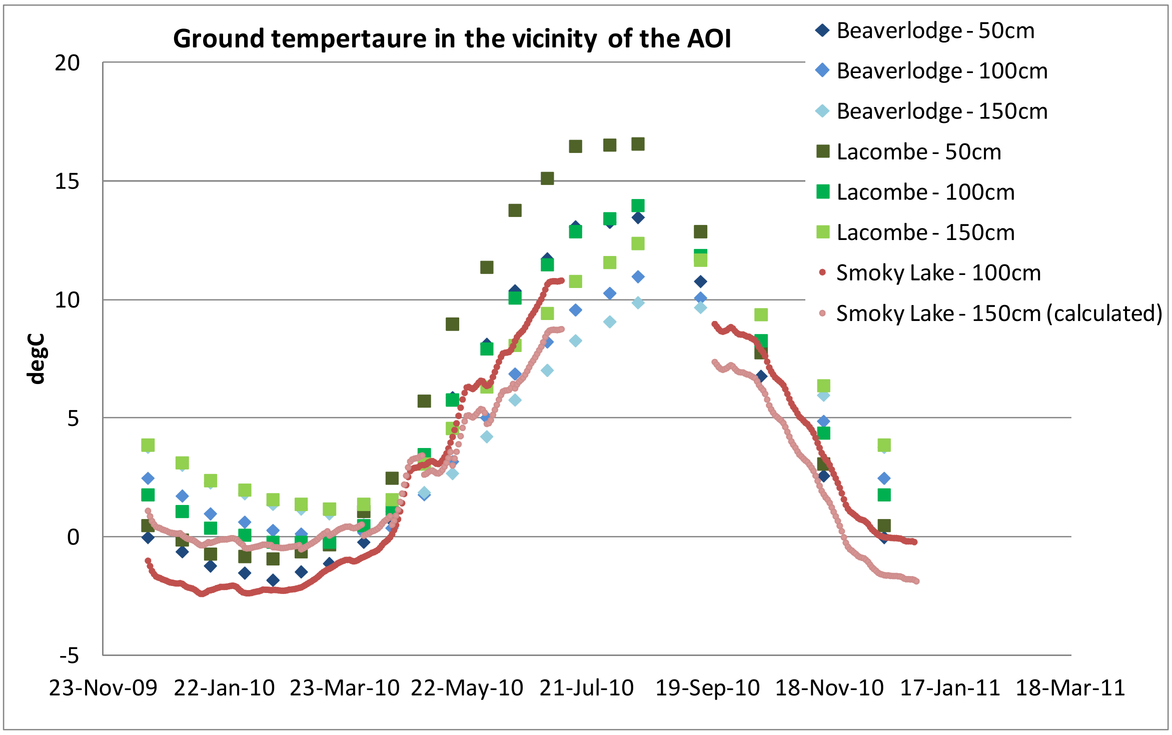
The following graph shows the maximum temperature recorded during each day at the Scotford upgrader location, over the period 2006 to 2010 (all plotted on the same year for clarity).



As it can be seen, the maximum temperatures are consistent over the survey period. It should be noted however that these temperatures were recorded only one hour maximum per day and that therefore, most of the day was colder than the temperatures displayed on the graph above.

3.4. Ground temperature

Three data sets were available that each represents the ground temperature near the AOI (their locations are given in appendix). The following graph compares the three different data sets for 2010.

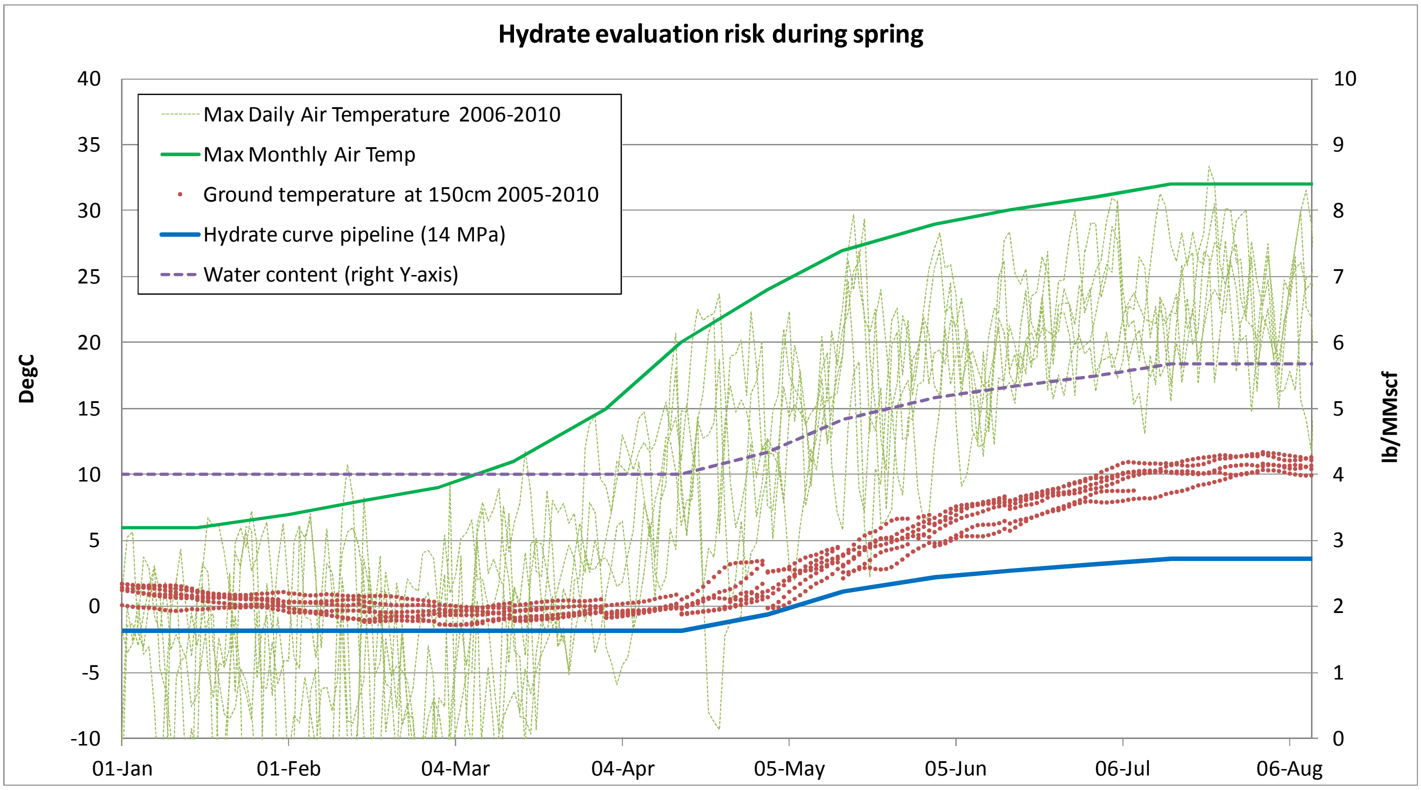


Beaverlodge and Lacombe, although further away from the AOI than Smoky Lake, include the ground temperature at 50cm, 100cm and 150cm. Smoky Lake shows only the ground temperature at 50cm (not plotted) and 100cm but its available dataset covers 2005 to 2010 and is also the coldest survey.

Since the pipeline minimum burial depth is 150cm, the ground temperature considered in this analysis is the temperature of the Smoky Lake dataset, pro-rated at 150cm based on the interpolations of Beaverlodge and Lacombe data at 100cm and 150cm. This ensures that the most conservative ground temperatures have been considered in this analysis as the temperature deeper than 150cm will be warmer in the winter.

3.5. Hydrate risk analysis

The graph below shows the evaluation of the hydrate risk during the first part of the year, based on the assumptions detailed above.



- The light dotted green curves represent the maximum recorded air temperature per day over the 2006-2010 period at the Scotford upgrader location (as in 3.3.)
- The solid green line is an approximation of the maximum air temperature possible during the year (based on the dotted green lines)
- The dotted purple curve is the water content of the CO_2, based on the performance of the TEG unit (as per 3.2.) and the approximation of the maximum air temperature (solid green line)
- The solid blue curve is the maximum hydrate temperature at 14 MPa with respect to the water content given by the purple dotted curve (as per 3.1.)
- The red points represent the minimum ground temperature at 150cm depth over the 2005-2010 period (as per 3.4.).

As it can be seen, if the TEG unit was providing 6 lbs/MMscf of water in the CO_2 stream all year long, the pipeline would be in the high risk zone since the minimum hydrate temperature would be ~5 degC at 14 MPa whereas the ground temperature would be close to 0 degC during the first months of the year.

The blue curve plotted on the graph above considers that the TEG unit can actually provide 4 lbs/MMscf of water in the CO_2 below 22degC and 6 lbs/MMscf between 22 and 34degC (as in 3.2.). It can be clearly seen that in that case the pipeline is not at risk anymore since the minimum hydrate temperature is lower than the ground temperature at all time.

Besides, this plot considers several conservative assumptions that strengthen the conclusions of this analysis:

- The dotted green lines (on which the solid green line is based on) represent the maximum temperatures seen during the day, i.e. these temperatures were actually measured only 1 hour maximum during each day
- The solid green line (on which the performance of the TEG unit is based on) over estimates most of the time the actual maximum recorded air temperature by several degrees
- The TEG unit performance is assumed linear with air temperature whereas it is actually better
- The ground temperature considers the coldest survey set recorded in the vicinity of the AOI
- The considered ground temperature is at 150cm whereas most of the pipeline will be buried deeper
- The hydrate formation temperature is at maximum pipeline pressure (14MPa)

Therefore, it can be stated that providing the expected performance of the TEG unit in the winter with the current design becomes an actual requirement, the pipeline will be safe from hydrate formation in all cases throughout the year.

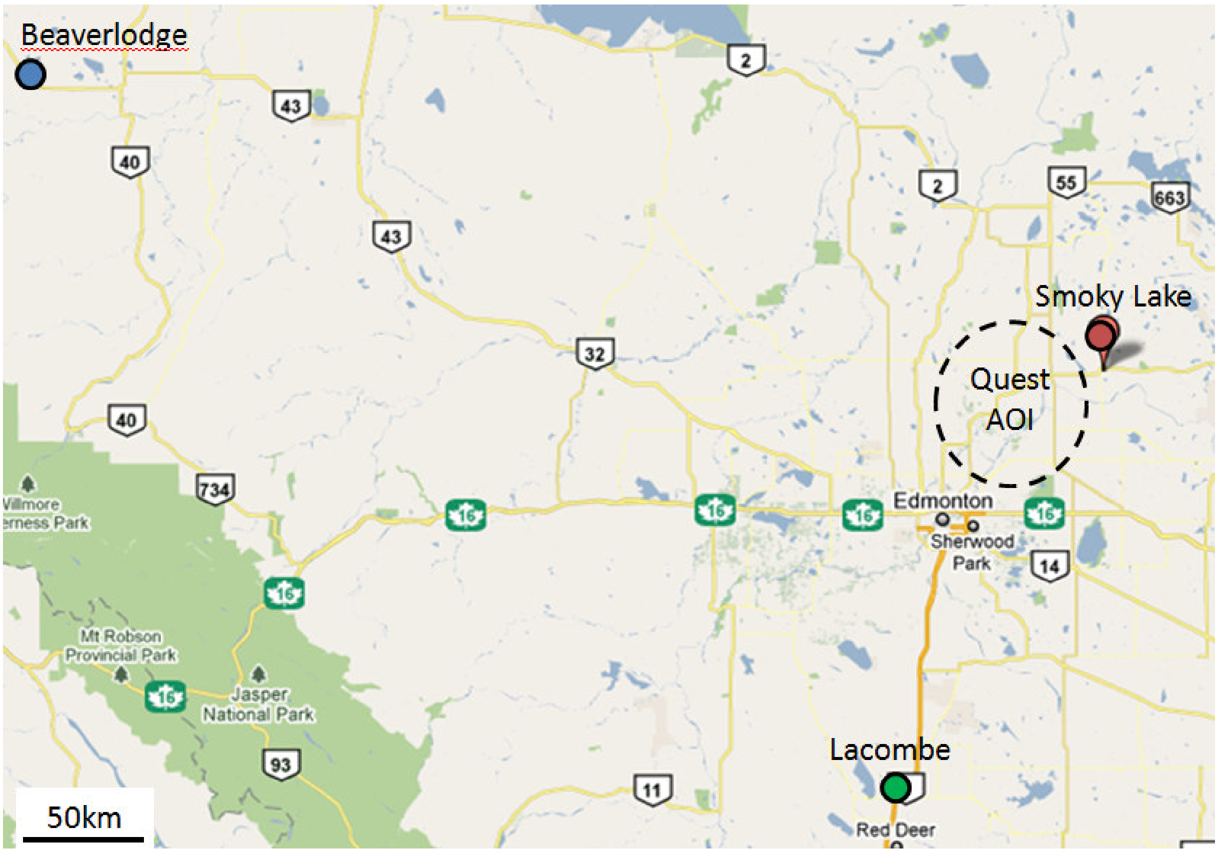
4. Conclusion

This document has shown that the current design requirements were not stringent enough to ensure the pipeline would not operate within the hydrate formation zone at all time. In particular, the behaviours of the ground temperature and air temperature make spring the most risky time of the year.

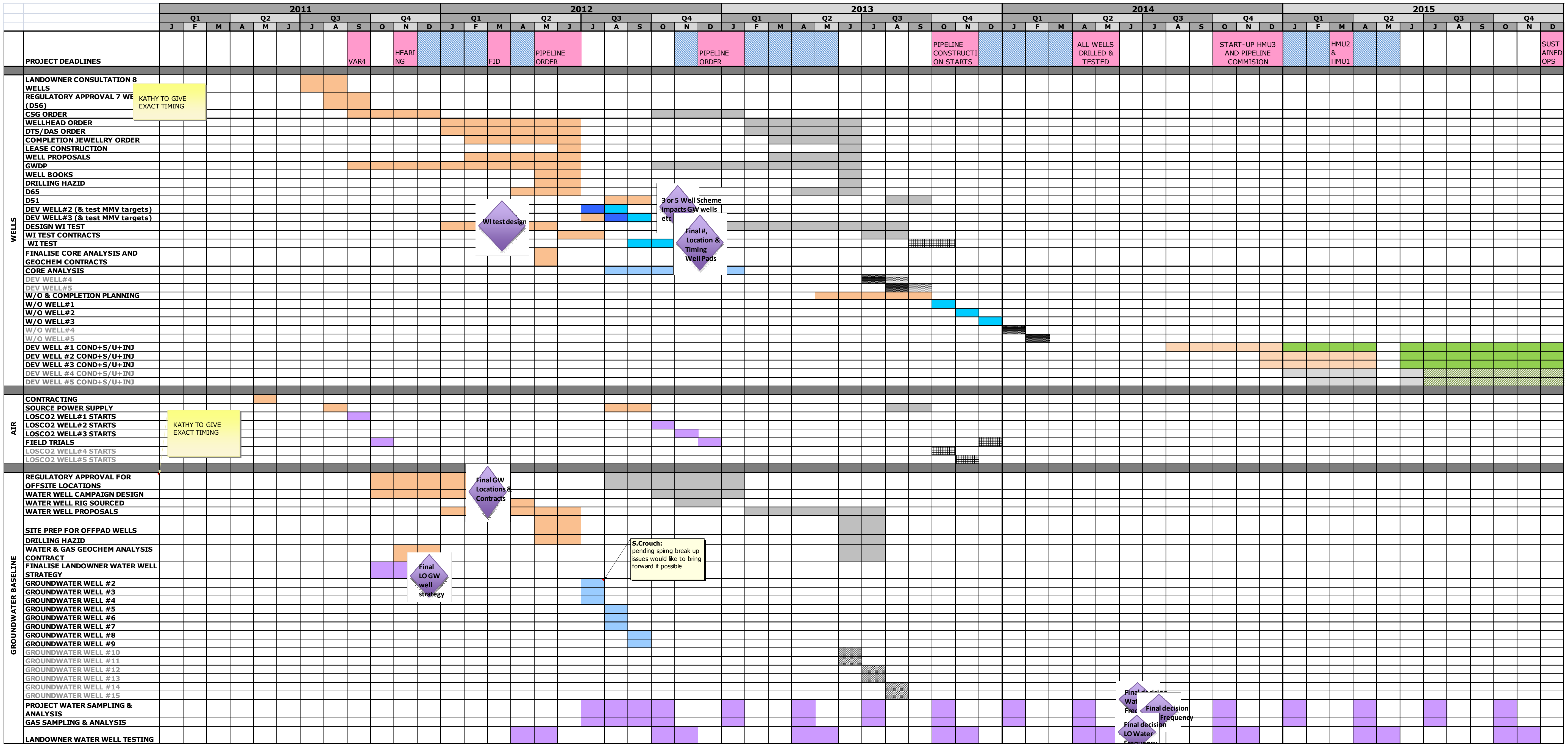
It was shown that if the TEG unit performance requirements are updated to guarantee a dehydratation of the CO_2 stream to 4 lbs/MMscf in the winter (below 22 degC air temperature) and 6 lbs/MMscf in the summer (between 22 and 34 degC air temperature), then the risk of hydrate formation in the pipeline is insignificant.

The current design of the TEG unit can meet these updated requirements with no impact on CAPEX and limited impact on OPEX, it is therefore recommended to include the expected winter performance of the TEG unit as an actual requirement.

Map of ground temperature surveys locations

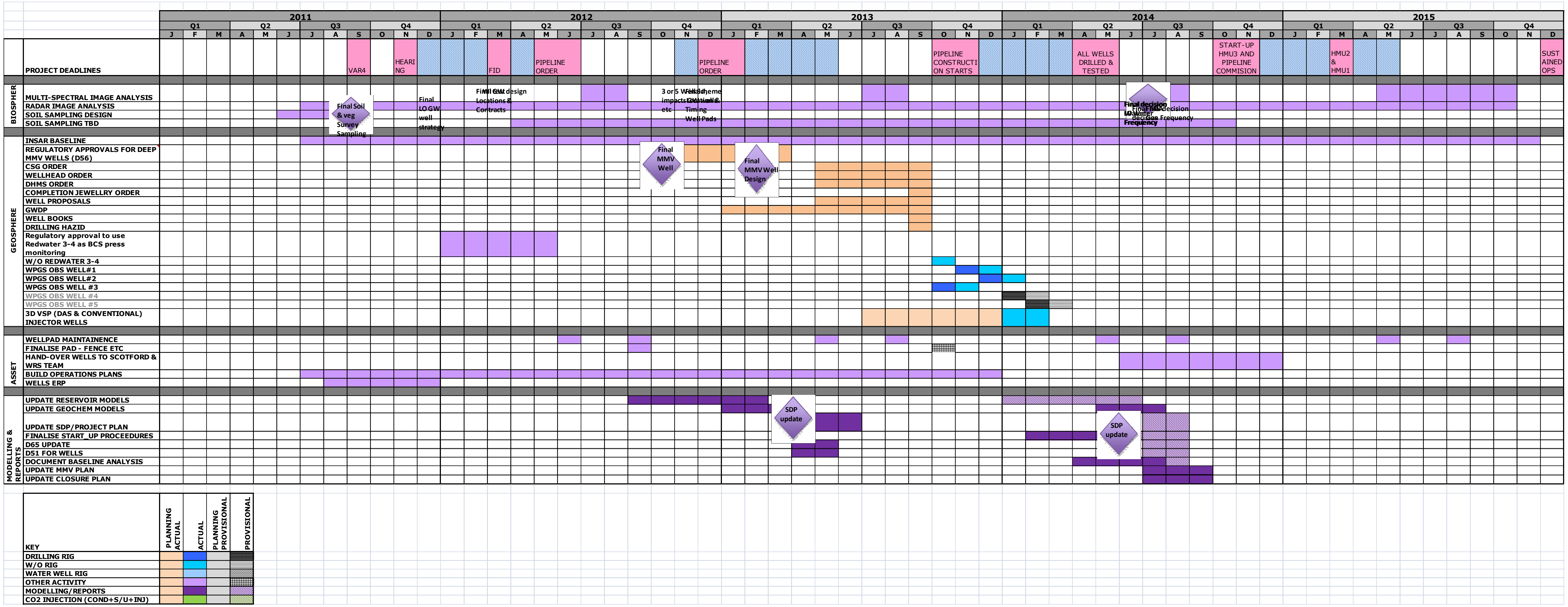


APPENDIX 6. STORAGE DEVELOPMENT PLAN TIMELINE TO START-UP



(continues on next page)

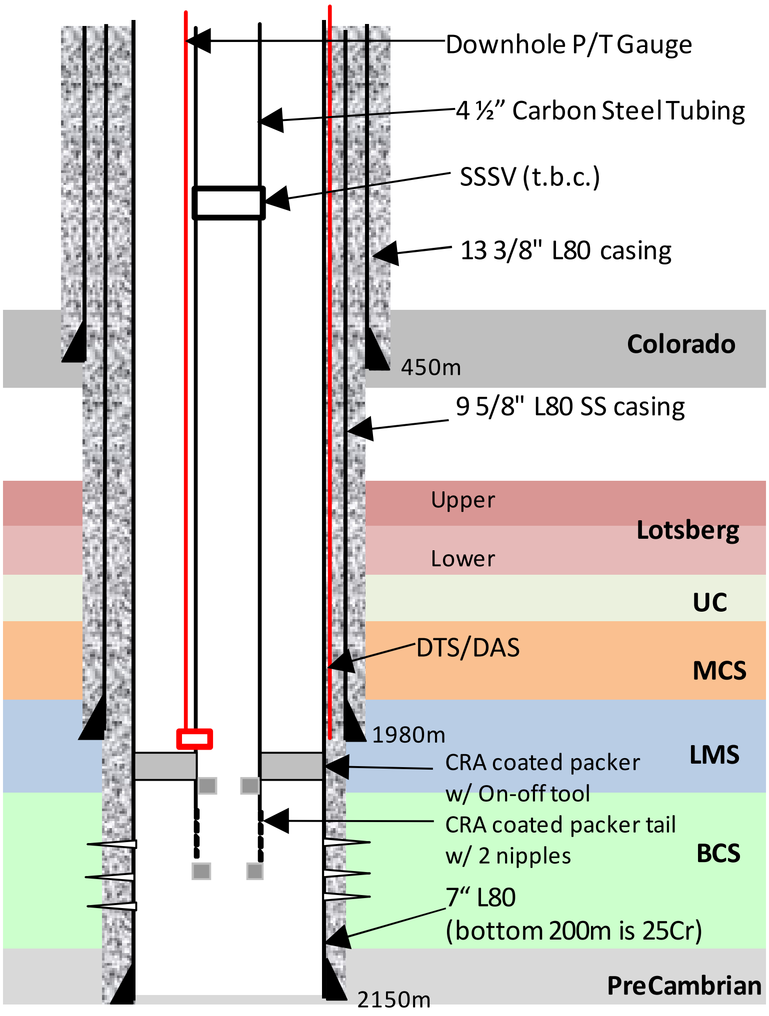
APPENDIX 1



2011
2012
2013
2014
2015
Q1
Q2
Q3
Q4
J F M A M J J A S O N D
PROJECT DEADLINES
VAR4
HEARI NG
FID
PIPELINE ORDER
PIPELINE ORDER
PIPELINE CONSTRUCTI ON STARTS
ALL WELLS DRILLED & TESTED
START-UP HMU3 AND PIPELINE COMMISION
HMU2 & HMU1
SUST AINED OPS
BIOSPHERE
MULTI-SPECTRAL IMAGE ANALYSIS
RADAR IMAGE ANALYSIS
SOIL SAMPLING DESIGN
SOIL SAMPLING TBD
Final Soil & veg Survey Sampling
Final LO GW well strategy
Final GW design Locations & Contracts
3 or 5 Wells impacts etc
Final Scheme Locations & Timing Well Pads
Final decision LO Water Frequency
Final MA decision Gas Frequency
GEOSPHERE
INSAR BASELINE
REGULATORY APPROVALS FOR DEEP MMV WELLS (D56)
CSG ORDER
WELLHEAD ORDER
DHMS ORDER
COMPLETION JEWELLRY ORDER
WELL PROPOSALS
GWDP
WELL BOOKS
DRILLING HAZID
Regulatory approval to use Redwater 3-4 as BCS press monitoring
W/O REDWATER 3-4
WPGS OBS WELL#1
WPGS OBS WELL#2
WPGS OBS WELL #3
WPGS OBS WELL #4
WPGS OBS WELL #5
3D VSP (DAS & CONVENTIONAL) INJECTOR WELLS
Final MMV Well
Final MMV Well Design
ASSET
WELLPAD MAINTAINENCE
FINALISE PAD - FENCE ETC
HAND-OVER WELLS TO SCOTFORD & WRS TEAM
BUILD OPERATIONS PLANS
WELLS ERP
MODELLING & REPORTS
UPDATE RESERVOIR MODELS
UPDATE GEOCHEM MODELS
UPDATE SDP/PROJECT PLAN
FINALISE START_UP PROCEEDURES
D65 UPDATE
D51 FOR WELLS
DOCUMENT BASELINE ANALYSIS
UPDATE MMV PLAN
UPDATE CLOSURE PLAN
SDP update
SDP update
KEY
PLANNING ACTUAL
ACTUAL
PLANNING PROVISIONAL
PROVISIONAL
DRILLING RIG
W/O RIG
WATER WELL RIG
OTHER ACTIVITY
MODELLING/REPORTS
CO2 INJECTION (COND+S/U+INJ)

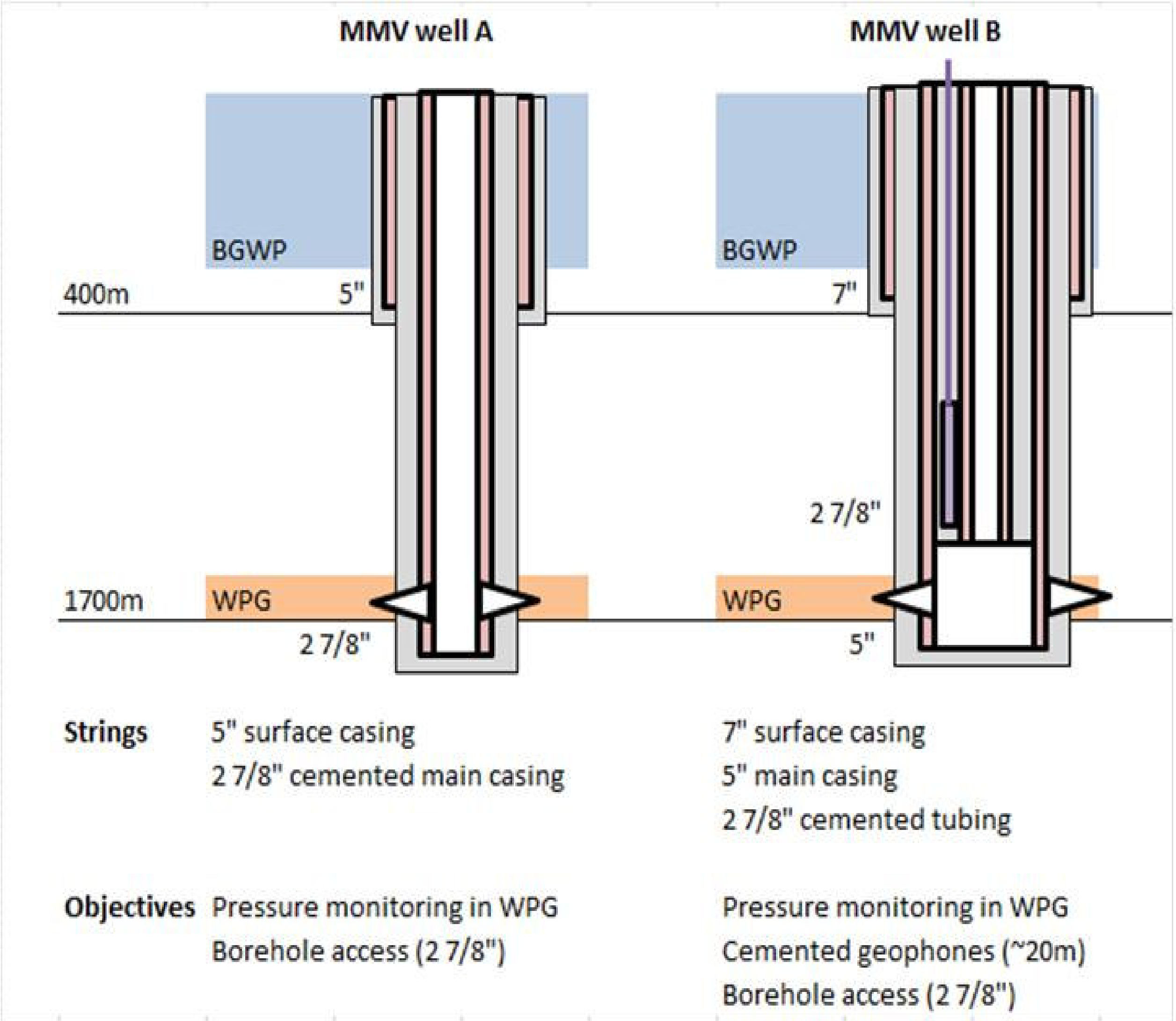
APPENDIX 7. WELLS SCHEMATICS

Injection well schematics



(Depths are indicative only)

Deep MMV wells schematics



APPENDIX 8. INTEGRATED CONTROL SYSTEM SCHEMATIC

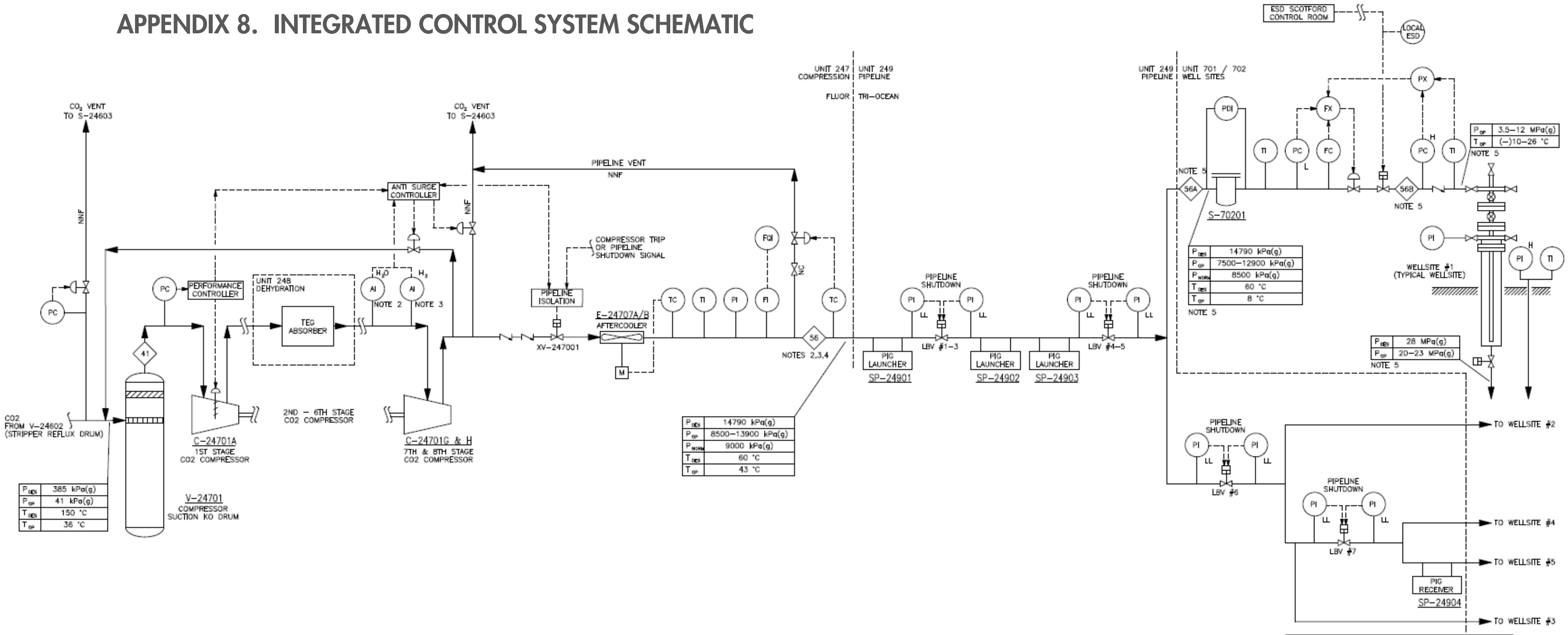


TABLE 1. REFERENCE PROCESS FLOW DIAGRAMS

DWG. NO.	REV.
247.0001.000.040.001	0B
247.0001.000.040.002	0B
247.0001.000.040.003	0B
248.0001.000.040.001	0B
249.0001.000.040.001	D
249.0001.000.040.002	D
249.0001.000.040.003	D
249.0001.000.040.004	D

TABLE 2. MAXIMUM IMPURITIES FOR CO2 PRODUCT TO PIPELINE.

COMPONENT	MAXIMUM IMPURITIES
H_2	5.0 MOL%
TEG	27 PPM MAX
H_2O	8 LB/MMSCF

NOTES

1. FOR PROCESS FLOW DETAILS, SEE REFERENCE PROCESS FLOW DIAGRAMS IN TABLE 1 BELOW.
2. COMPRESSOR IS PLACED IN RECYCLE OPERATION ON HIGH MOISTURE CONTENT OF 8 LB/MMSCF.
3. COMPRESSOR IS PLACED IN RECYCLE OPERATION ON UPSET HYDROGEN CONTENT OF 2.5 MOL%.
4. REFER TO TABLE 2 FOR MAXIMUM IMPURITIES OF CO2 PRODUCT TO PIPELINE.
5. DATA PROVIDED BY OTHERS.
6. REFER TO 246.0001.000.040.006 FOR SYSTEM MATERIAL BALANCES.

REV	ISSUED DATE	DESCRIPTION	DWN	CHKD	ENG	APP	APP	CLNT APP
B		RE-ISSUED FOR INFORMATION						
A		ISSUED FOR INFORMATION						

SHELL CANADA

FLUOR

SYSTEM INTEGRATION DIAGRAM
QUEST CCS PROJECT
CO2 COMPRESSION, PIPELINE AND
WELL INTEGRATION

SCALE: TOE DWG. No.:

SHELL DWG NO.: 246.0001.000.040.005 REV. B

APPENDIX 9. RESPONSIBILITIES AND ACCOUNTABILITIES FOR MMV

R – Responsible
A – Accountable
C – Consulted
I – Informed

	Scotford Control Room	SCAN Surveillance Team	SCAN Environmental Team	Quest Venture Subsurface Team	Quest Venture Regulatory Team	SCAN Geophysical Operations	SCAN Seismic Processing	P&T Geophysics	P&T Remote Sensing	Completions and Well Interventions	Well Engineering	Third-Party Service Provider	Government Regulators	Knowledge Sharing
Reviews														
Daily surveillance by exception	C	A												
Monthly surveillance reviews	C	A		C										
Quarterly surveillance reviews	I	R	C	A	C	I	I	I	I	I				
Annual MMV reviews	I	C	C	A	C	I	I	I	I	I				I
Reporting														
Monthly injection volume reporting	C	R			A								C	I
Annual performance reporting	C	C	C	R	A								C	I
MMV Plan update	C	C	C	R	A								C	I
Closure Plan update	C	C	C	R	A								C	I
In-Well Monitoring														
Respond to SCR alarm	A	I		I										
Respond to Calgary alarm	C	A	R	C										
Respond to Calgary alarm	C	A		C										
Planned well maintenance	A	C		C	I									
Well interventions	C	A		C	I					R				
Geosphere Monitoring														
VSP acquisition	I	I		A		R	C	C						I
VSP processing		I		A		C	R	R						I
VSP interpretation		C		A		C	C	C						I
VSP performance review		C		A	I	C	C	C						I
Surface seismic acquisition	I	I		A		R	C	C						I
Surface seismic processing		I		A		C	R	R						I
Surface seismic interpretation		C		A		C	C	C						I
Surface seismic performance review		C		A	I	C	C	C						I
Microseismic acquisition		A		C	C	R								I
Microseismic processing		A		C								R		I

Activity	Scotford Control Room	SCAN Surveillance Team	SCAN Environmental Team	Quest Venture Subsurface Team	Quest Venture Regulatory Team	SCAN Geophysical Operations	SCAN Seismic Processing	P&T Seismic Processing	P&T Remote Sensing	Completions and Well Interventions Team	Well Engineering	Third-Party Service Provider	Government Regulators	Knowledge Sharing
Microseismic interpretation		A		C								R		I
Microseismic performance review		A		C	I							R		I
InSAR acquisition		I		A			C					R		I
InSAR processing		I		A								R		I
InSAR interpretation		C		A										I
InSAR performance review		C		A	I									I
Deploy InSAR corner reflectors	I	C		A	C	R								
Verify or update reservoir models	I	C		A	I									I
Hydrosphere Monitoring														
Groundwater fluid sampling	C	C	A	C	C							R		
Groundwater fluid analysis		C	A	C	C							R		I
Groundwater WEC & PH acquisition		A	C	C								R		I
Interpretation of monitoring data		C		A	I							R		I
Monitoring performance review		C		A	I							R		I
Biosphere Monitoring														
Remote sensing acquisition		I	A	C					C			R		I
Remote sensing processing		I	A	C					C			R		I
Remote sensing interpretation	I	C	A	C	I				C			R		I
Remote sensing performance review	I	C	A	C	I				C			R		I
Soil & vegetation sampling	C		A	C	C							R		
Soil & vegetation analysis	I		A	C	I							R		I
Soil & vegetation performance review	I		A	C	I							R		I
Atmosphere Monitoring														
LOSCO2 acquisition	C	C	A	C	C				C			R		I
LOSCO2 processing		I	A	I					R					I
LOSCO2 interpretation	I	C	A	C	I				R					I
LOSCO2 performance review	I	C	A	C	I				R					I

APPENDIX 10. DATA MANAGEMENT FOR MMV

Monitoring activities required under the MMV Plan will generate large amounts of data from many different sources.

Table 18-1: Summary of the Data Management Plan for MMV.

Legend: ET - SCAN Environmental Team; GR - Government Regulators; KS - Knowledge Sharing; SCR - Scotford Control Room; SP - SCAN Seismic Processing; ST - SCAN Surveillance Team; TBD – To be decided.

	Data Source		Data Transfer			Data Storage			Alarm &
Technology	Type	Location	Volumes	Frequency	Mechanism	Database	Location	Users	Location
LOSCO2 - Line-of-Sight CO2 Gas Flux Monitoring	CO2 flux, time stamp, beam id (ASCII)	Project injection well pads	<1 Mb/day	Daily	Cellular network, via SCR, to Calgary	TBD (Novel, maybe PI)	Calgary	ST, GR, ET, KS	Yes, in Calgary
MIA - Multi-Spectral Image Analysis	Geotiff images	Satellite	<1 Gb/year	<4 times per year	FTP from Spatial Energy direct to Calgary	Arc Spatial Data Engine	Calgary	ST, GR, ET, KS	No
ATM - Artificial Tracer Monitoring NTM - Natural Tracer Monitoring WC - Water Chemistry Monitoring	Chemical species concentrations (ASCII)	1. Project groundwater wells 2. Landowner water wells N.B. Not all on injection well pads	< 100 Mb/year	Annually	FTP from Service Provider direct to Calgary	TBD (Check with NW)	Calgary	ST, GR, ET, KS	No
CBL - Cement Bond Logs USIT - USIT Logs	LAS files (ASCII)	1. Project injection wells 2. Project deep observation wells 3. Project groundwater wells	<10 Mb/survey	1. Once at time of well construction 2. Every 5 years for injectors	FTP from Service Provider direct to Calgary	Openworks	Calgary	ST, GR, ET, KS	No
WEC - Water Electrical Conductivity Monitoring WPH - Water pH Monitoring	Attribute, time, well id (ASCII)	1. Project groundwater wells N.B. Not all on injection well pads	< 1Mb/day	Daily	Cellular network, via SCR, to Calgary	PI (Check with NW)	Scotford	ST, GR, ET, KS	Yes, in SCR
INSAR - Surface Uplift Monitoring	Displacement, time, location (ASCII)	Satellite	< 1Gb/year	Quarterly	FTP from Service Provider direct to Calgary	Arc Spatial Data Engine (Check with Geomatics)	Calgary	ST, GR, ET, KS	No

SEIS3D - 3D Surface Seismic VSP3D - 3D Vertical Seismic Profile	SEGY (Binary)	Seismic surveys around injectors	<10 Gb per survey	Every 1-10 years	FTP from Service Provider direct to Calgary	Openworks	Calgary	ST, GR, ET, KS, SP	No
DTS - Distributed Temperature Sensing	Temperature, depth, time, well id (ASCII)	Project injection wells	<10 Mb/day	Daily	Cellular network, via SCR, to Calgary	DTS database	Calgary	ST, GR, ET, KS, SP	Yes, in SCR
DAS - Distributed Acoustic Sensing	Noise, depth, time, well id (ASCII)	Project injection wells	<10 Mb/day	Daily	Cellular network, via SCR, to Calgary	TBD (TDS database)	Calgary	ST, GR, ET, KS, SP	Yes, in SCR
DHMS - Down-hole Microseismic Monitoring	1. SEGY (Binary) 2. Event catalogue (ASCII)	Project deep observation wells on injection well pads	<10 Mb/day	Daily	Cellular network or local internet connection, via SCR, to Calgary	TBD	Calgary	ST, GR, ET, KS, SP	Yes, in SCR
Well-head pressure and temperature gauge	Pressure & temp	Injector wellhead	<1 Mb/day	real time	SCADA	PI	Calgary via Scotford	ST, GR, KS, SCR	
Down-hole pressure and temperature gauge	Pressure & temp	Injector -downhole	<1 Mb/day	real time	SCADA	PI	Calgary via Scotford	ST, GR, KS, SCR	Yes, Scotford
Annulus pressure gauge	Pressure	Injector annulus	<1 Mb/day	real time	SCADA	PI	Calgary via Scotford	ST, GR, KS, SCR	Yes. Scotford
Injection rate metering	mass flow rate	Injector wellpad	<1 Mb/day	real time	SCADA	PI	Calgary via Scotford	ST, GR, KS, SCR	
Choke position	% opening	Injector wellpad	<1 Mb/day	real time	SCADA	PI	Calgary via Scotford	ST, GR, KS, SCR	

Pressure drop across choke	Pressure drop	Injector wellpad	<1 Mb/day	real time	SCADA	PI	Calgary via Scotford	ST, GR, KS, SCR	Yes. Scotford
Temperature drop across choke	Temp. drop	Injector wellpad	<1 Mb/day	real time	SCADA	PI	Calgary via Scotford	ST, GR, KS, SCR	
Pressure drop across filter	Pressure drop	Injector wellpad	<1 Mb/day	real time	SCADA	PI	Calgary via Scotford	ST, GR, KS, SCR	Yes. Scotford
Surface controlled subsurface safety value status (SCSSV)	Open/close	Injector wellpad	<1 Mb/day	real time	SCADA	PI	Calgary via Scotford	ST, GR, KS, SCR	Yes. Scotford
Emergency shut-down valve status	Open/close	Injector wellpad	<1 Mb/day	real time	SCADA	PI	Calgary via Scotford	ST, GR, KS, SCR	Yes. Scotford
Skid cabinet climate control status	Current status	Injector wellpad	<1 Mb/day	real time	SCADA	PI	Calgary via Scotford	ST, GR, KS, SCR	Yes. Scotford
Cathodic protection status	Current status	Injector wellpad	<1 Mb/day	real time	SCADA	PI	Calgary via Scotford	ST, GR, KS, SCR	Yes. Scotford
Chemical Injection	mass flow rate	Injector wellpad	<1 Mb/day	real time	SCADA	PI	Calgary via Scotford	ST, GR, KS, SCR	Yes. Scotford
Well-head CO2 concentration gauge	Leak detector	Injector wellpad	<1 Mb/day	real time	SCADA	PI	Calgary via Scotford	ST, GR, KS, SCR	Yes. Scotford
UPS power supply status	Strength	Injector wellpad	<1 Mb/day	real time	SCADA	PI	Calgary via Scotford	ST, GR, KS, SCR	Yes. Scotford

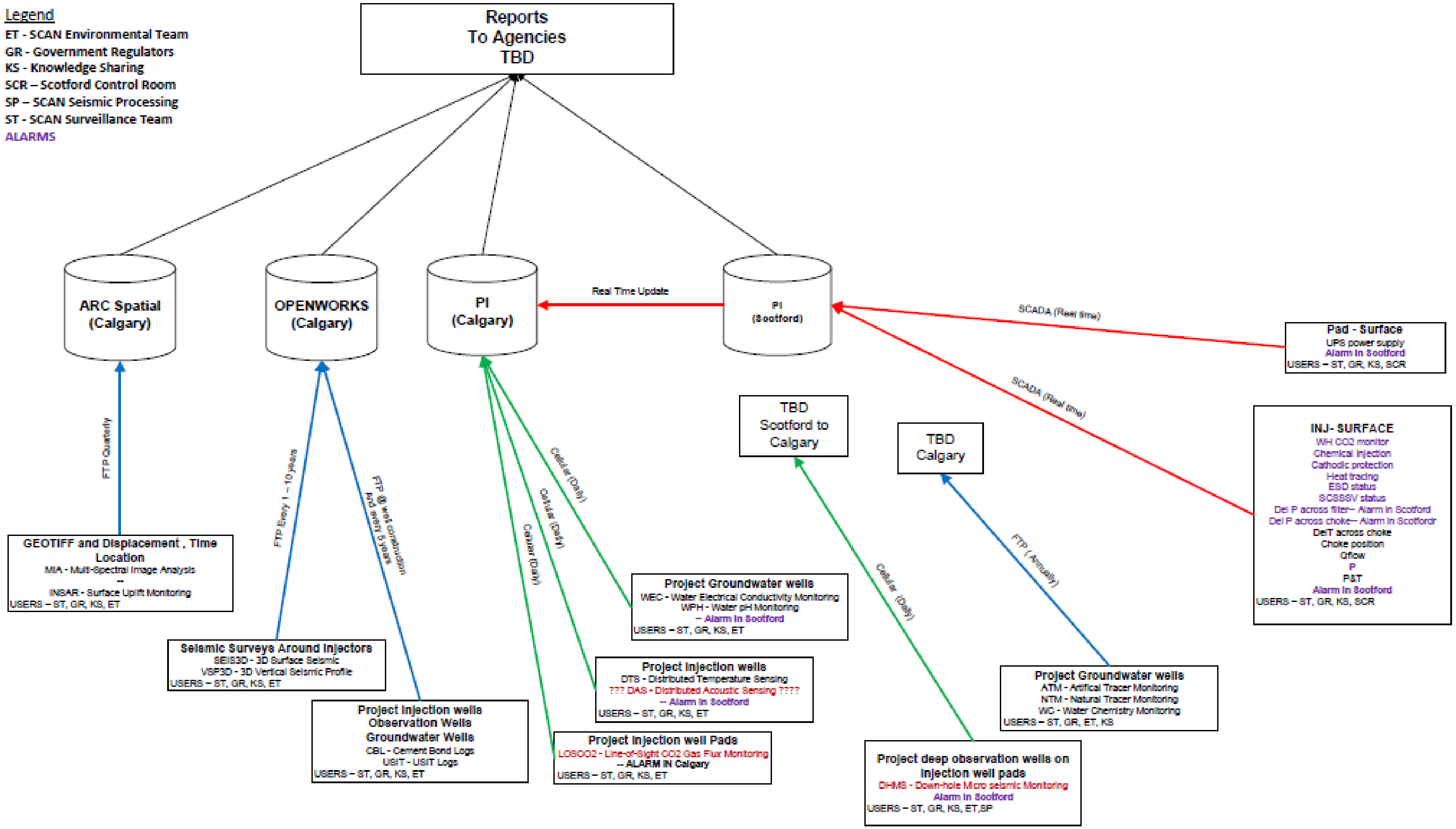
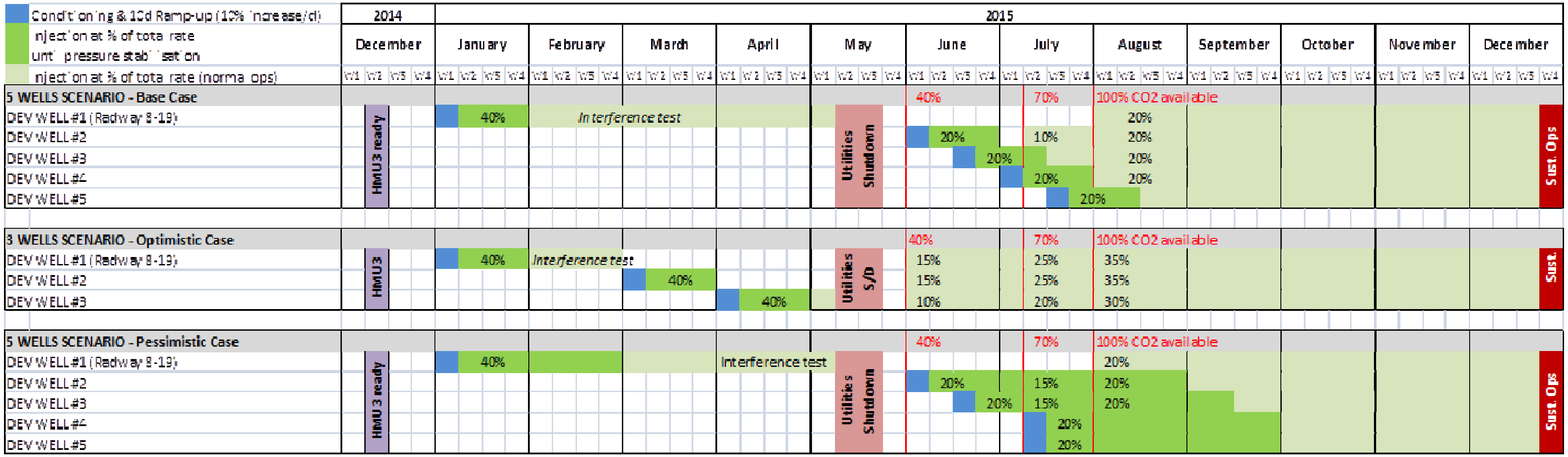


Figure 18-1 Schematic illustration of the flow of data from sources to databases

APPENDIX 11. WELLS START-UP SCHEDULE



Note: the 10-day ramp-up (blue square) appears over one week only in the schedule above but does last 10 days.

Base Case

The base case scenario is a 5-well development and a long interference test. Each well should take 25 days to start-up (ramp up, in blue, and establishment of stable injectivity, in green). Once the first well has demonstrated stable injectivity, injection will continue to support the interference test until the HMU2 turnaround at the latest. The other injectors will be then started using a minimum capacity of 20% per well, and the extra capacity, if any, will be spread over the wells previously started up. Injection in the well starting up is to take priority and injection in wells that are already commissioned should not continue at the expense of risking system instabilities that could trip the start-up sequence. Depending on the first well ramp-up it may also be decided to shorten the next wells ramp-up.

Optimistic Case

The optimistic case considers a 3-well development and a very short interference test (i.e. pressure response is seen quickly in other injectors). In that case, the interference test can be stopped and the other wells can be started before the HMU2 turnaround. The minimum required capacity is 35% per well as there are only 3 injection wells in this case.

Pessimistic Case

The pessimistic case considers a 5-well development and a long time required to ramp-up and/or achieve stable injectivity in the first well. The start-up sequence will be the same as for the base case but as more time is required to prove stable injectivity, injection should continue at target rate in all starting wells and new wells should be ramped up only when extra capacity is available. However, all wells need to be started-up in time in order to have reached stable injectivity before Q4 2015. Therefore, the ramp-ups of the last wells may have to be done simultaneously to meet this deadline. Also, it could be decided not to perform the interference test, but start one or two wells before the Q2 2015 turnaround. It should be noted that since the first well will have been started with 40% of total flow, the start-up of the following wells may be longer since the injection rate per well is 20% of total flow.

APPENDIX 12. STORAGE CAPEX AND OPEX ESTIMATES FOR THE 3, 5 AND 8 WELL CASES.

1) 3 well scenario

Quest SDP Costs_inj3(1).xlsx

2) 5 well scenario

Quest SDP Costs_inj5(1).xlsx

3) 8 well scenario

Quest_SDP_Costs_inj8(1).xlsx