Disclaimer
This Report, including the data and information contained in this Report, is provided to you on an "as is" and "as available" basis at the sole discretion of the Government of Alberta and subject to the terms and conditions of use below (the "Terms and Conditions"). The Government of Alberta has not verified this Report for accuracy and does not warrant the accuracy of, or make any other warranties or representations regarding, this Report. Furthermore, updates to this Report may not be made available. Your use of any of this Report is at your sole and absolute risk.

This Report is provided to the Government of Alberta, and the Government of Alberta has obtained a license or other authorization for use of the Reports, from:

> Shell Canada Energy, Chevron Canada Limited. and Marathon Oil Canada Corporation, for the Quest Project
>
> (collectively the "Project")

Each member of the Project expressly disclaims any representation or warranty, express or implied, as to the accuracy or completeness of the material and information contained herein, and none of them shall have any liability, regardless of any negligence or fault, for any statements contained in, or for any omissions from, this Report. Under no circumstances shall the Government of Alberta or the Project be liable for any damages, claims, causes of action, losses, legal fees or expenses, or any other cost whatsoever arising out of the use of this Report or any part thereof or the use of any other data or information on this website.

Terms and Conditions of Use
Except as indicated in these Terms and Conditions, this Report and any part thereof shall not be copied, reproduced, distributed, republished, downloaded, displayed, posted or transmitted in any form or by any means, without the prior written consent of the Government of Alberta and the Project.

The Government of Alberta's intent in posting this Report is to make them available to the public for personal and non-commercial (educational) use. You may not use this Report for any other purpose. You may reproduce data and information in this Report subject to the following conditions:

- any disclaimers that appear in this Report shall be retained in their original form and applied to the data and information reproduced from this Report
- the data and information shall not be modified from its original form
- the Project shall be identified as the original source of the data and information, while this website shall be identified as the reference source, and
- the reproduction shall not be represented as an official version of the materials reproduced, nor as having been made in affiliation with or with the endorsement of the Government of Alberta or the Project

By accessing and using this Report, you agree to indemnify and hold the Government of Alberta and the Project, and their respective employees and agents, harmless from and against any and all claims, demands, actions and costs (including legal costs on a solicitor-client basis) arising out of any breach by you of these Terms and Conditions or otherwise arising out of your use or reproduction of the data and information in this Report.

Your access to and use of this Report is subject exclusively to these Terms and Conditions and any terms and conditions contained within the Report itself, all of which you shall comply with. You will not use this Report for any purpose that is unlawful or prohibited by these Terms and Conditions. You agree that any other use of this Report means you agree to be bound by these Terms and Conditions. These Terms and Conditions are subject to modification, and you agree to review them periodically for changes. If you do not accept these Terms and Conditions you agree to immediately stop accessing this Report and destroy all copies in your possession or control.

These Terms and Conditions may change at any time, and your continued use and reproduction of this Report following any changes shall be deemed to be your acceptance of such change.

If any of these Terms and Conditions should be determined to be invalid, illegal or unenforceable for any reason by any court of competent jurisdiction then the applicable provision shall be severed and the remaining provisions of these Terms and Conditions shall survive and remain in full force and effect and continue to be binding and enforceable.

These Terms and Conditions shall: (i) be governed by and construed in accordance with the laws of the province of Alberta and you hereby submit to the exclusive jurisdiction of the Alberta courts, and (ii) ensure to the benefit of, and be binding upon, the Government of Alberta and your respective successors and assigns.

Heavy Oil

Controlled Document

Quest CCS Project

Quest CCS Project
Well Functional Specifications

Project	Quest CCS Project
Document Title	Quest CCS Project Well Functional Specifications
Document Number	07-3-ZW-7770-0001
Document Revision	01
Document Status	Final
Document Type	ZW7770-Functional Design Specification
Owner / Author	Vincent Hugonet
Issue Date	2011-06-10
Expiry Date	None
ECCN	EAR 99
Security Classification	
Disclosure	None

Revision History shown on next page

Revision History

REVISION STATUS			APPROVAL		
Rev.	**Date**	**Description**	**Originator**	**Reviewer**	**Approver**
00	2011-04-20	Draft for Review	V. Hugonet	S. Malik	S. Crouch
01	2011-06-10	Final	V. Hugonet	S. Malik	S. Crouch

- All signed originals will be retained by the UA Document Control Center and an electronic copy will be stored in Livelink

Signatures for this revision

Date	Role	Name	Signature or electronic reference (email)
	Originator	Vincent Hugonet	
	Reviewer	Satinder Malik	
	Approver	Syrie Crouch	

Summary

This document presents the Well Functional Specifications of the Quest CCS injection and MMV wells, as part of the Well Delivery Process. It will be used as a basis for issuing the Well Technical Specifications, which are a required deliverable for DG4.

Keywords

Quest, CCS, injection well, MMV wells, WFS

DCAF Authorities

Date	Role	Name	Signature or electronic reference (email)
	TA-2	James Clark	RE Quest Well Functional Specificatic

TABLE OF CONTENTS

1. OVERVIEW

The Quest CCS (Carbon Capture and Storage) Project proposes injection and subsurface storage of up to 1.2 Mtpa of CO_2 from the Scotford Upgrader into the deep saline formation of the Basal Cambrian Sand (BCS). Three appraisal wells have been drilled to date: Redwater 11-32-55-21W4, Redwater 3-4-57-20W4 and Radway 8-19-59-20W4. Radway is the only well amongst these three intended to be kept as a CO_2 injector. A Conceptual Completion Document [Ref. 1] was issued in November 2010 which confirms the well design inputs used for Radway 8-19 are still applicable for all future injection wells. For this reason, the Radway well design is the recommended analogue for all remaining injector well designs.

This document and attached excel spreadsheet contains the technical data required to complete the detailed design for the future CO_2 injectors and MMV wells to be drilled as part of the project. At this stage of project definition, all wells are considered as 'vertical' wells.

The project considers between 3 and 10 injection wells, with a base case of 5. For each injector well (IW), 1 deep MMV well (DW) targeting the formations overlying the storage complex and three shallow MMV groundwater wells (GW) within the Base Ground Water Protection (BGWP) are considered.

2. KEY SUCCESS CRITERIA

The Quest wells have the following key success criteria, by order of priority:

1- **Safety**
   - Goal Zero is achieved during the drilling, completion and testing of all Quest wells

2- **Mechanical Integrity**
   - Delivering wells with sound mechanical integrity, especially competent cement bonds
   - Successful installation of the monitoring system behind casing (DTS/DAS/Geophones)
   - Successful installation of the control and monitoring system in the tubing (P/T gauges, SC-SSSV)

3- **Injectivity (for the injection wells only)**
   - Successful injectivity test enabling to determine the stable water injectivity of the BCS with an acceptable injection profile across the perforation interval

- Minimized skin after the injection test (e.g. successful perforation, stimulation/N_2 kick-off, and no plugging of the formation due to the injectivity test)

4- **Data acquisition**

- Successful acquisition of quality logs over the whole storage complex or other target formation
- Successful MDT pressure analysis and fluid sampling for geochemical analysis
- Successful collection of target cores in each well
- Confirmation of fracture pressures within the LMS

3. TIMING

The table given below shows the current base case timeline for the wells drilling, completion and other related activities.

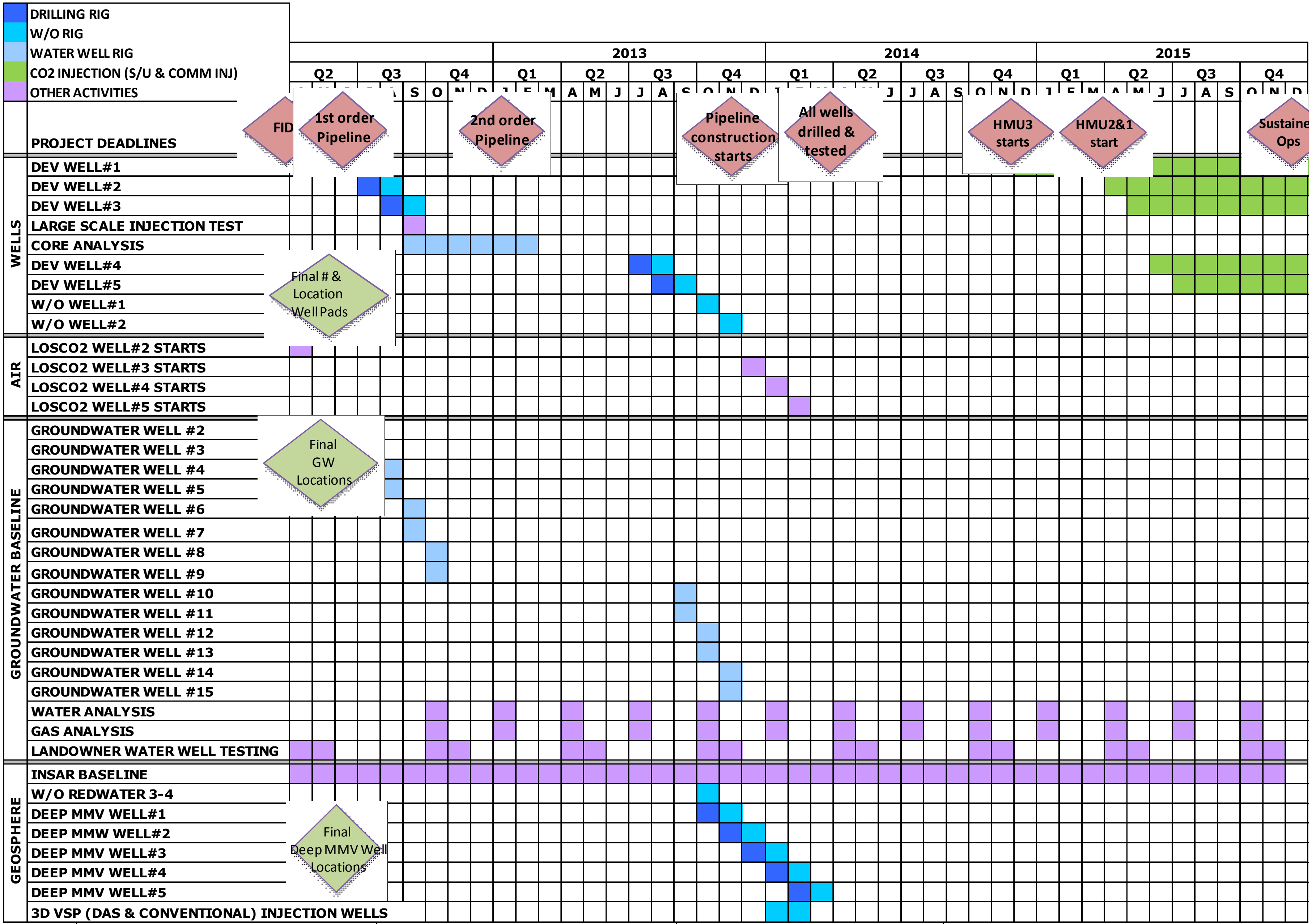
The IW#1 is Radway 8-19-59-20W4 and was already drilled and tested from September to December 2010. It is currently suspended but needs to be recompleted before the start of injection. The IW#2 and IW#3 are planned for post FID, Q3 2012 (DEV WELL #2 and #3 in the timeline schematic) and will enable to narrow down the final number of required injectors. The remaining IWs will be drilled in winter 2013-2014.

The DWs will be drilled in winter 2013-2014, during the same period the remaining IWs are drilled.

The GWs will be drilled when the well pads have been constructed: the GW for IW#1 is drilled and the GW for IW#2, IW#3 will be drilled in summer 2012. The same year, one GW will be drilled per BCS legacy well (4 GW wells in total) and 2 additional GW will also be drilled in the AOI (location to be determined). The remaining ones are scheduled to be drilled in Q2 2014. Since the BGWP and stratigraphy are not well known, there is a need for a pilot well prior to finalizing a completion zone for the remaining GWs. All 2014 pilot wells will need to be drilled first to allow time to analyze the data and choose the final completion zone; then all final GWs will be drilled and completed.

The HMU3 commissioning is expected to be completed by October 2014 and should therefore enable to start injection (at 40% of the total rate) in Q4 2014. It is expected that there will be a 4 month operating period prior to up to a month’s shut-in period during the tie-in for HMUs 1&2 which will be online end of Q1 2015. The system should then be able to run at 100% of the planned rate (1.2 Mtpa). Sustained operations must be achieved by end 2015 to maximize the governmental funding support of the project.

07-3-ZW-7770-0001



Heavy Oil

4. WELL PADS

4.1. Well pad Locations

The following table gives the base case locations of the 5 well pads (base case development), based on the 2011 3D seismic interpretation.

Well pad	Well pad #1	Well pad #2	Well pad #3	Well pad #4	Well pad #5
Surface location	8-19-59-20W4 (already existing)	7-11-59-20W4	5-35-59-21W4	15-16-60-21W4	10-6-60-20W4

Note: All wells assumed as 'Vertical' wells

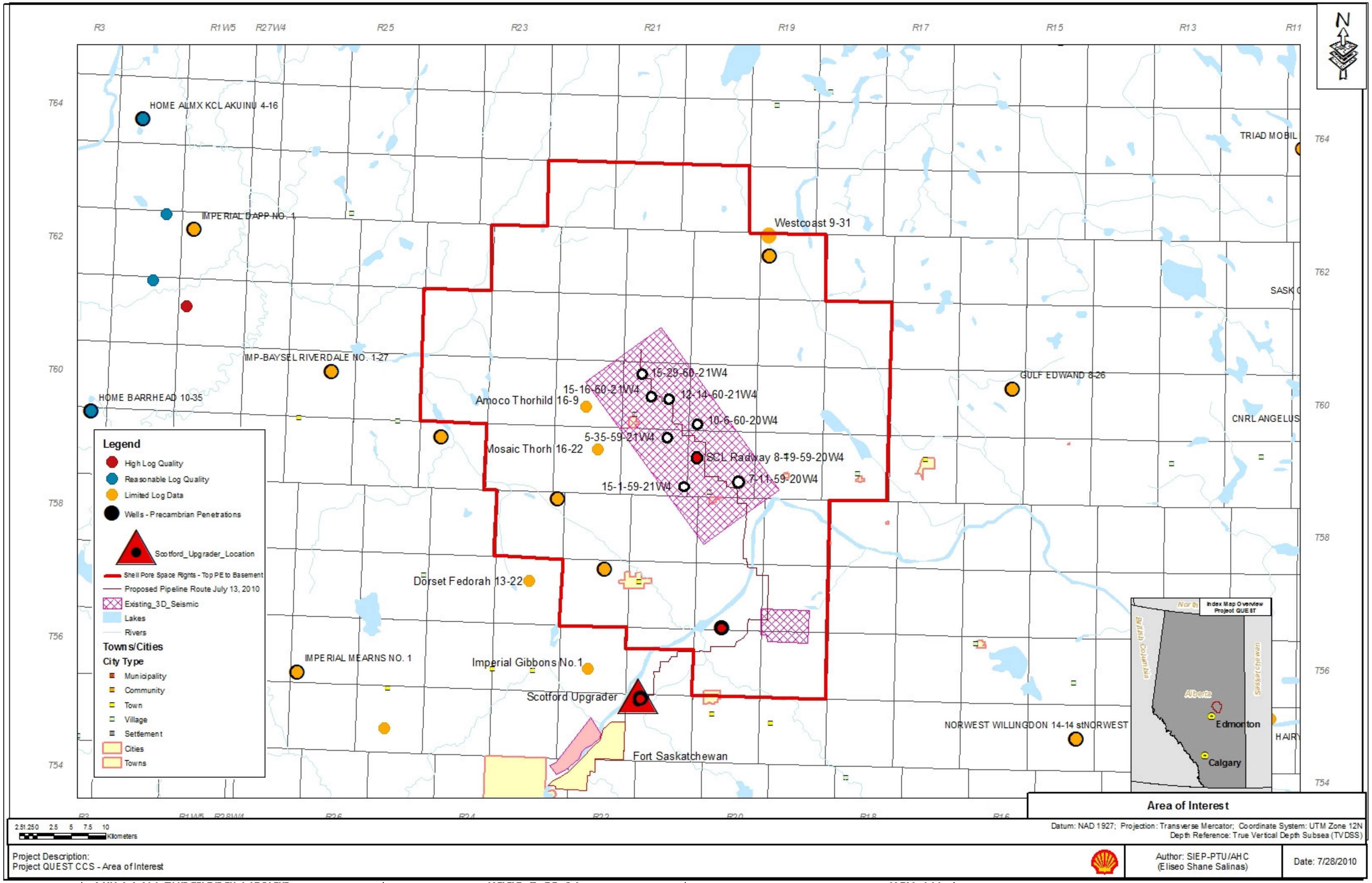
Three additional well pads have been identified as contingency locations:

Well pad Contingencies	Well pad #6	Well pad #7	Well pad #8
Surface location	15-1-59-21W4	15-29-60-21W4	12-14-60-21W4

The Quest project includes one well pad per injection well, with well pads 5-6 km apart. One deep MMV well per injection well will be drilled, possibly on the same well pads. Three shallow MMV wells will be drilled for each injector well, at least one of which will be located on each well pad.

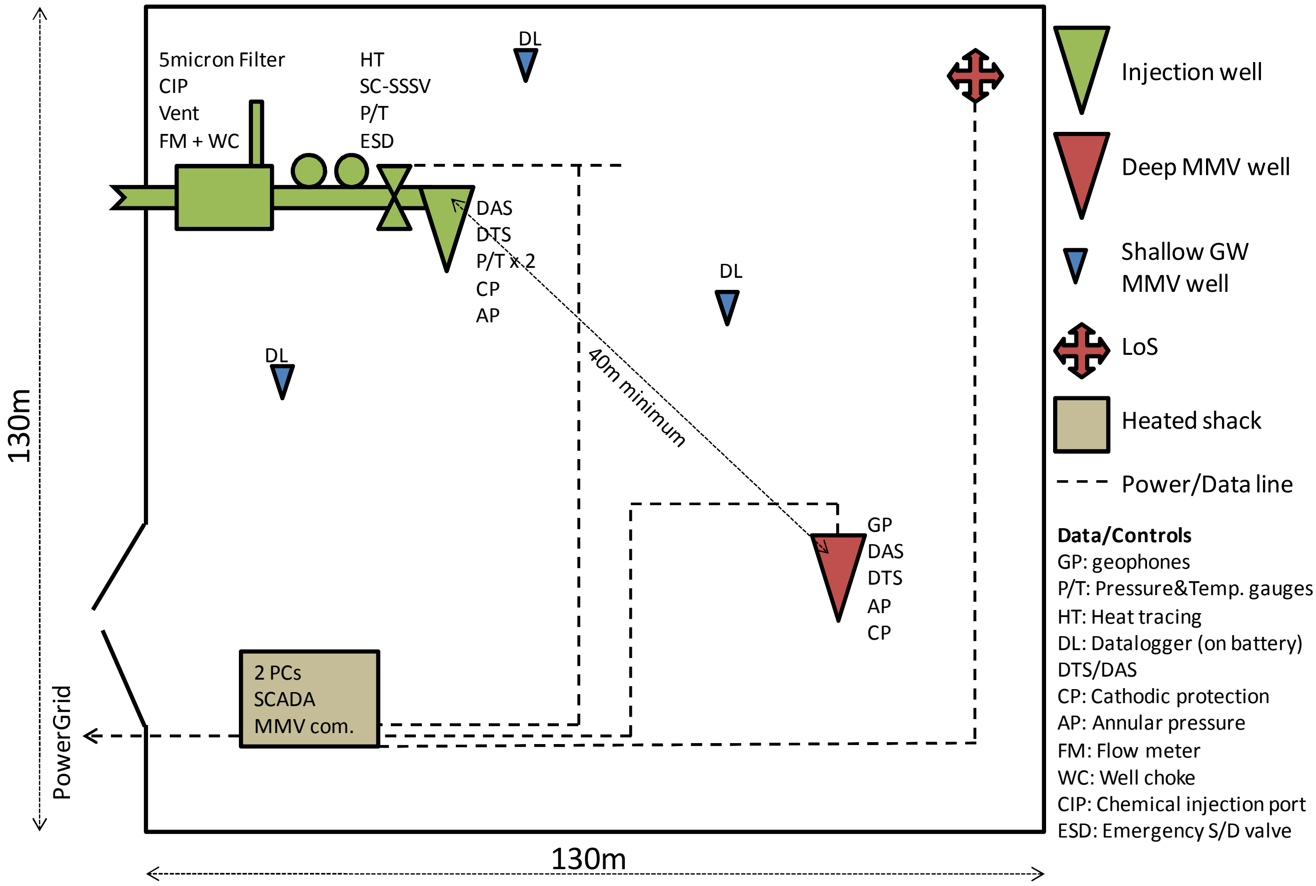
The following map shows the Quest Area of Interest (AOI) with the base case and contingency well pad locations.

07-3-ZW-7770-0001



4.2. Well pad Layout

The following schematic presents the conceptual well pad layout as per the current basis of design (BOD). The P&IDs of the surface kit (i.e. along the CO_2 stream) are being finalized at the time of issue of this document. Therefore, the following schematic is conceptual only and presents all the possible equipment that could be on the injection well pad. In particular, it should be noted that not all the MMV wells will necessarily be drilled on the injection well pad (current commitment on each injection well pad includes only 1 GW, the two other GWs are contingency wells).



The well pads should be fully fenced off to prevent access to the wells or the shack. Lock key/code should be given to the ERP team members, Scotford, and the subsurface support team in Calgary. The landlord should also be able to open the fence lock but he/she should sign-in and sign-off with Scotford when entering and leaving the well pad.

A minimum distance of 40m is recommended between wellheads and any other well testing kit (e.g. flare stack, frac tanks, etc), and also between wellheads and the lease boundaries to ensure the drilling and service rigs can operate safely. CW&I must be consulted prior to reclaiming the portion of the lease before start-up of the operation.

5. SUBSURFACE DEFINITION

The CO_2 injector wells, deep MMV wells, and shallow MMV wells will target the Basal Cambrian Sand, Winnipegosis, and Belly River group above the BGWP, respectively.

5.1. Prognosis

The following table is based on the Radway well and gives the subsurface prognosis to be considered for the additional injector and MMV wells.

Formation	Prog. Depth MD (m)	Cuttings Depth MD (m)	Log Depth MD (m)	Sub-Sea Depth (m)	Difference From Prognosis
Lea Park	206.0	209.0	209.0	437.58	3.0
Colorado	328.0	329.0	330.0	316.58	2.0
2nd White Specks	485.0	469.0	463.5	183.08	-21.5
Base Fish Scales	534.0	534.0	534.0	112.58	0.0
Viking	589.0	589.0	588.3	58.28	-0.7
Joli Fou	603.0	602.0	613.5	33.08	10.5
Mannville	622.0	626.0	623.0	23.58	1.0
Glauconite SS	754.0	740.0	760.0	-113.42	6.0
Ostracod Zone	764.0	767.0	796.2	-149.62	32.2
Ellerslie	769.0	769.0	799.1	-152.52	30.1
Calmar	833.0	830.0	830.0	-183.42	-3.0
Nisku	845.0	845.0	846.0	-199.42	1.0
Ireton	885.0	901.0	902.3	-255.72	17.3
Duvernay	1085.0	1065.0	1062.6	-416.02	-22.4
Cooking Lake	1154.0	1146.0	1147.7	-501.12	-6.3
Beaverhill Lake	1250.0	1231.0	1231.5	-584.92	-18.5
Moberly	1264.0	1264.0	1277.45	-630.87	13.45
Christina	1338.0	1338.0	1339.4	-692.82	1.4
Calmut	1379.0	1378.5	1380.0	-733.42	1.0
Firebag	1402.0	1403.0	1404.5	-757.92	2.5
Slave Point	1442.0	1443.5	1444.0	-797.42	2.0
Watt Mountain	1459.0	1456.0	1458.6	-812.02	0.4
Prairie Evaporite	1470.0	1476.0	1477.4	-830.82	7.4
Winnipegosis	1603.0	1598.5	1600.35	-953.77	-2.65
Contact Rapids	1624	1614.0	1615.65	-969.07	-8.35
Ernestina Lake	1702.0	1682.0	1684.5	-1037.92	-17.5
Top U. Lotsberg	1718.0	1697.5	1700.0	-1053.42	-18.0
Top L. Lotsberg	-	1837.5	1783.8	-1193.92	-
Basal Red Beds	1893.0	1871.0	1874.0	-1227.42	-19.0
Upper Marine Silt	1916.0	1913.5	1916.0	-1269.42	0.0
Middle Cambrian Shale	1943.0	1931.0	1931.0	-1284.42	-12.0
Lower Marine Sand	1983.0	1973.0	1975.0	-1328.42	-8.0
Basal Cambrian Sand	2057.0	2038.0	2041.3	-1394.72	-15.7
Precambrian	2095.0	2084.0	2087.0	-1440.42	-8.0

5.2. Expected Reservoir Properties

The table below summarizes the expected reservoir properties for the target formations of each type well (refer to attached excel chart in appendix for complete well details).

Reservoir Info	CO_2 Injector Well	Deep MMV Well	Shallow MMV Well

Name of Zone	BCS	Winnipegosis	Shallow aquifer above the BGWP and below the vadose zone
Zone Depth Top (MD/TVD)	2041m	1600m	20m
Zone Depth Bottom (MD/TVD)	2087m	1615m	20 – 150m
Expected Reservoir Pressure (min - max)	20 MPa (initial) - 32 MPa (final)	15.2 MPa in Winnipegosis	2000kPa
Reservoir Temperature (min - max)	15 degC (0 WHT) - 60 degC (initial)	56 degC	5 – 25 degC
Porosity	0.16	variable	variable
Permeability	~150md	0.01 - (+10mD)	variable
NTG	90%	no data	no data
Fluid saturation	100% formation brine	100% formation brine	100% fresh to brackish
Formation water density	1190 kg/m3 @ reservoir conditions	1187 kg/m3	1015 – 1075 kg/m3
TDS	311,000 mg/l	270,000mg/l (+/- 10%)	1000 – 20000mg/l
H2S	0	0	0
Fracture closure pressure gradient	16.8 kPa/m (BCS Fracture extension pressure is 20.6 kPa/m)	No data	No data
Pore pressure gradient	11.7 kPa/m (P= (SS depth - 330.6) / 0.08538	11.7kPa/m	~10kPa/m

The formations in the BCS overburden are all expected to be hydrostatically pressured with some possible minor overpressures associated with hydrocarbons in the Manville or localized overpressures associated with isolated compacted or uplifted sand lenses, and some possible minor under pressures in Cooking Lake as seen during Radway drilling.

Extrapolation of pressure data in the three Quest wells already drilled in the AOI suggests a BCS reservoir pressure of 20.1 MPa at 1400 m TVDss (2046.8 mAHD).

At reservoir conditions the formation water fluid gradient in the BCS is expected to be 11.7 kPa/m (1190 kg/m3) based on a TDS of 311,000 ppm.

5.3. H_2S Prediction

Sour gas is sometimes found in Viking, Nisku and Leduc reservoirs as a result of bacterial contamination by injected water. The well site is up dip of the Redwater Leduc field and if sour gas from that reservoir has escaped upward into the Nisku and migrated along the regional dip there is a chance of encountering it. Numerous wells have tagged the Nisku in the area without incident, but the rig should be prepared in the unlikely event sour gas is encountered. Sour gas is always a potential hazard in all carbonates from top Devonian to the top of the Cambrian.

An anticipated H_2S release rate for the well was calculated based on Dir-56 guidelines and the CAPP guidelines in order to determine emergency planning zone (EPZ) for the proposed location. An area with a radius of 40 km surrounding the different well locations was evaluated to investigate potential shallower H_2S zones in this well. This area more than exceeds the minimum Dir-56 requirement to assess an area of three townships by three ranges, to ensure that all potential locations that were being evaluated leading up to the final well site selection are covered by this analysis.

The maximum H_2S release rate for the different well locations is calculated to be 0.0477 m^3/s which correspond to an EPZ of 0.33 km based on a maximum H_2S concentration of 19.5% in the Leduc zone. This is a conservative estimate, based on the pool maximum H_2S concentration recorded for a few wells more than 15 km away from any proposed well site that have measured H_2S levels around 3%. Full details are available in the H_2S release rate report [Ref. 2 and 3].

No sour content below the Devonian is reported.

The EPZ calculated above is valid for the drilling phase of this well only and does not cover the potential development phase of this well (CO_2 injection).

Well Engineer to consider the above fact in choosing casing grade and casing connections.

6. CO_2 INJECTION PERFORMANCE

6.1. CO_2 Composition

Total Stream Composition	Normal Mol %	Upset Mol %
CO_2	99.2%	95%
CO	0.02%	0.15%
N_2	0.00%	0.01%
H_2	0.68%	4.27%
CH_4	0.09%	0.57%
H_2O	<52 PPM	52 PPM

Note: There is no H_2S in the Injected fluid

6.2. Injector Well Operating Envelope

Parameter	Minimum	Maximum
Wellhead Pressure (WHP)	**0.1 MPa** (Atmospheric pressure)	**14 MPa** (Max pipeline discharge Pressure)
Wellhead Temperature (WHT) while injecting	**-10 degC** (CO_2 from pipeline is at 0 degC min. but JT effect over choke)	**+18 degC** (CO_2 stream into pipeline inlet is at 61 degC max)
WHT while SI	**-45 degC** (min winter ambient air temperature)	**+35 degC** (max summer ambient air temperature)
Bottom hole pressure (BHP)	**20 MPa** (Initial reservoir pressure)	**32 MPa** (Maximum injection pressure legally allowable)
Bottom hole temperature (BHT)	**15 degC**	**60 degC**
Steady State flowing rate	**175,000 Sm3/d** (0.12 Mtpa)	**900,000 Sm3/d** (0.6 Mtpa)

7. EVALUATION AND LOGGING REQUIREMENTS

7.1. Measurement and Logging While Drilling

7.1.1. Sample Collection while Drilling:

One wellsite geologist will be required from spud to end of well. Due to high ROP in shallow and intermediate hole, a second wellsite geologist will be required from surface to intermediate casing point. Shell will follow the sampling guidelines indicated in Directive 56 including:

- Sample collection:
  1. 1 vial every 5 m from surface to final well TD as per Directive 56
  2. 1 washed 500 gram bag and 1 washed and dried vial sample every 5 m from surface to final TD for Shell Canada.
- Testing: Mud gas detector from surface casing to TD operated by the Wellsite Geologist. Record any changes to mud system including changes associated with LCM pills etc.
  1. Collect 3 Isotubes every 5m from surface to TD.

7.1.2. Logging While Drilling

- Shallow MMV Wells – May require MWD-GR. Feasibility ongoing.
- Deep MMV Wells – no MWD-GR required.
- CO2 injection wells – no MWD-GR required.

7.2. Coring

There should be some budget set aside for the cores to be shipped to Houston for SCAL work. All BCS cores will have to be transported in a temperature controlled truck because they are friable and need to be kept at ~5 degrees Celsius.

Well type	CO_2 injection well	Deep MMV well	Shallow MMV well
Surface hole	None	None	Shallow zones - similar to water wells on 8-19
Intermediate hole	Lotsberg salts (only in well #2, under preparation). Winnipegosis in Well #2 and possibly	None	Shallow zones - similar to water wells on 8-19

	Cooking Lake and Winnipegosis in Well #3 under preparation). These can be 3" core.		
Main hole	BCS in all IWs	Winnipegosis in at least one DW	None
Core size	4" for the BCS core.	Note: Core size might dictate the hole size and hence the casing size. May be possible only for DWB type well. WE to advice	

7.3. Open Hole Logging

No dedicated open hole surface logs are required. This data will be acquired through surface casing along with the intermediate logging runs.

Wells with a larger intermediate hole diameter that require MDT sampling in Winnipegosis and/or Cooking Lake (i.e.CO2 injection wells #2 and #3) WILL REQUIRE A SPECIAL MDT TOOL, DESIGNED FOR LARGE BOREHOLES. THE ONE TOOL IN THE WORLD CURRENTLY RESIDES IN MIDDLE EAST AND MAY NEED TO BE BROUGHT INTO THE COUNTRY FOR CO2 INJECTION WELLS #2 and #3.

Well type	CO_2 injection well	Deep MMV well	Shallow MMV well
Surface hole	EMS-GR	EMS-GR	EMS-GR
Intermediate hole	**Run1:** AIT-APS-2TLD-HNGS-PPC-EMS *(GR, Neutron, Density, Caliper, Resistivity)* **Run2:** MSIP-2PPC-GR *(GR, Sonic)* **Run3:** MDT – GR *(Modular Formation Dynamic Tester, GR)*	N/A	N/A
Main hole	**Run1:** ZAIT-GPIT-APS-TLD-PPC-HNGS *(GR, Neutron, Density, Tri-axial Resistivity)*	**Run1:** AIT-APS-2TLD-HNGS-PPC-EMS *(GR, Neutron, Density, Caliper, Resistivity)*	EMS-GR

	Run 2: OBMI-GPIT-MSIP-2PPC-GR *(Borehole Image, Sonic, GR)* **Run 3:** wire line magnet for run 4 **Run3:** MRX-GR *(NMR, GR)* **Run4:** MDT-GR *(Modular Formation Dynamic Tester, GR)*	**Run2:** MSIP-2PPC-GR *(GR, Sonic)* **Run3:** MDT – GR *(Modular Formation Dynamic Tester, GR)*	

7.4. Cased Hole Logging

Logging to be done both at 0 & 7 MPa pressure pass. Minimum wait on cement before the logging is 48 hrs to maximize cementation quality.

Well type	CO_2 injection well	Deep MMV well	Shallow MMV well
Surface hole	USIT-CBL-VDL-GR-CCL+Temp	USIT-CBL-VDL-GR-CCL+Temp	None
Intermediate hole	USIT-CBL-VDL-GR-CCL+Temp	If applicable, USIT-CBL-VDL-GR-CCL+Temp	None
Main hole	**Run1:** USIT-CBL-VDL-GR-CCL+Temp **Run 2:** Zero offset VSP (Vertical Seismic Profile)	USIT-CBL-VDL-GR-CCL+Temp	None

Note: WE to decide on cement rheology behind respective casing strings considering what formation fluids the cement will be exposed to and decide on placement strategy e.g. two stage vs. single stage cementing, etc.

7.5. Leak-Off Test

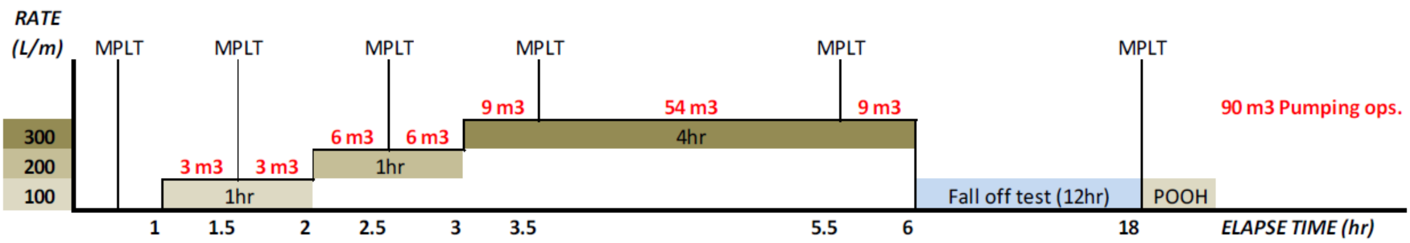
A leak off test is required to confirm the fracture gradient of the LMS in each injector well.

7.6. Fluid Sampling and Injection Testing

7.6.1. CO_2 Injector Wells

MDT pressure analysis and fluid sampling in the Winnipegosis and Cooking Lake formations in IW#2 and possibly in IW#3 will be required.

Once the injectors have been drilled and completed, an injection test will be performed. The following schematic presents the typical test procedure, although final injection and fall-off time may be changed.



The planned test would consist of injecting 5% water, filtered at 5 micron before the wellhead, in a three-rate step test to evaluate the stabilized injectivity of each well. Several MPLT will be run at different times to evaluate the injection profile in the well, and monitoring the bottom-hole pressure during a subsequent fall-off test. This fall-off test will bring additional information on the reservoir properties. The injection tests should also follow the recommendations issued from the AAR of Radway completion and testing operations (See Summary of Testing Operations 2 – Radway 8-19). The fluid to be used for testing will be determined at a later stage but fresh water is recommended over KCl in order to avoid any potential compatibility issue with the BCS brine.

7.6.2. Deep MMV Wells

In order to confirm the Winnipegosis is suitable for pressure monitoring in case of a leak outside of the storage complex, the perforated deep MMV wells may be tested with a water injectivity test to evaluate reservoir properties (fall-off test) or communication between well pads (interference test). If the Winnipegosis appear not suitable for pressure monitoring in case of a leak outside of the storage complex, it may be decided to recomplete the well to the Cooking Lake formation and repeat the perforation and testing operations.

MDT pressure analysis and fluid sampling for chemistry analysis will be carried out prior to any injection test.

8. DRILLING AND COMPLETION STRATEGY

8.1. Overall Drilling and Completion Strategy

All wells are planned to be vertical; therefore, no directional drilling is required. Mud should be designed to have in gauge hole, to prevent mud loss to the formation, and to ensure hole stability while drilling through each lithology (e.g. shales). Mechanical integrity is a key success criteria; therefore, maximum cementation quality is required to ensure competent cement bonds to surface. Wells should be designed to withstand the aforementioned surface and downhole conditions as well as be able to accommodate all future logging, surveillance, and well interventions as mentioned in this document. Appendix A gives a summary of drilling and completion requirements. The wells start-up strategy is further discussed in a specific document (PT Note – Wells start-up strategy – May11) but a summary is given in Appendix E.

8.2. CO_2 Injector Wells

8.2.1. Drilling and Completion

The injector wells' surface casing should be deep enough to ensure effective BGWP protection and should be cemented to surface. The surface casing should be protected with a deep intermediate casing, covering all the seals (MCS and Lotsberg) and cemented to surface. The main casing should be run from surface to bottom of the injection zone. As for Radway 8-19, a chrome casing should be selected for the bottom part of the main casing exposed to wet CO_2 flow. Besides, DTS/DAS will be installed behind the main casing for in-well monitoring.

The selected material should take into account the degradation induced by the different formation fluids, the degradation due to the CO_2 with the different contaminants in the injection stream, and the damage due to the different formation fluids mixing with the CO_2.

RTCI is currently being considered for all future CO_2 injection wells. It would be run on the outer production casing and across Winnipegosis and/or Cooking Lake, in order to provide pressure monitoring of these formations.

The BCS formation in the injector wells is a sensitive clastic formation; therefore, filtration to 5 microns or less is required to prevent causing formation damage during the completion. A small amount of clays is also anticipated in the BCS, so completion fluid should be chosen to minimize the risk of clay swelling.

Prior to completion, a minifrac in the top interval of the BCS may be required in order to get formation geo-mechanical properties (e.g. fracture extension and closure pressures). If this were to occur, the possibility of isolating the minifrac interval from the rest of the

BCS interval would need to be considered to ensure adequate CO_2 injection into the desired BCS interval.

Once the injector wells are completed, possibility exists to acidize the perforations. HCl could however react with Zeolite seen in the Radway core, and lead to formation damage. Tubing should be pickled with acid and a N2 flow back should be performed using coiled tubing to ensure clean tubulars and to ensure clean, connected perforations are obtained prior to injection test. Injection test with water will follow to confirm successful injectivity. The typical CO2 injection well schematic is given in Appendix B (Radway 8-19).

8.2.2. Perforation Strategy

In the injector wells, it is anticipated to only perforate the higher quality reservoir within the BCS, estimated to be the lower 30m of the BCS. The largest gun size possible, resulting in the deepest penetration shots with the highest shot density and largest hole size, is desired. The most dynamic underbalanced perforating is sought to achieve the best connectivity to the reservoir. A pressure gauge on the perforating gun BHA is requested to ensure adequate under-balance is achieved.

8.2.3. Well Conditioning for Start-up

Once the wells have been completed with their final completion, a conditioning will be executed just before the start-up phase. The objective of the conditioning is to displace the wells from test water to CO2, for the following reasons:

- The wells with test water will be at atmospheric pressure at wellhead. Flow Assurance studies show that opening the pressurized pipeline (10 MPa) to atmospheric pressure will result in significant hydrate formation that could compromise the start-up operations
- Displacing the wells to CO2 in a controlled manner will avoid any process operational upsets to induce stop of start-up operations with potentially CO2 and brine in the well, which could lead to significant corrosion in the carbon steel tubing.

Therefore, it is proposed that to slowly displace all the wells to CO2 using a 5 MPa CO2 truck just before each start-up. The wells start-up strategy is further described in a specific document [Ref. 4].

8.3. Deep MMV Wells

8.3.1. Drilling and Completion

The deep MMV wells have as objectives to monitor the pressure in the Winnipegosis and/or micro seismic activity in the storage complex. There are two types considered: the first type (DWA) for pressure monitoring in the Winnipegosis while keeping the ability to access the borehole with various tools, and the second type (DWB) for passive seismic with geophones cemented in place outside the tubing with the ability to access the borehole thru-tubing.

In the event the deep MMV wells are completed to the Cooking Lake back-up target formation instead of the Winnipegosis, RTCI could be deployed along with pressure gauges in the Cooking Lake formation.

The deep MMV wells should offer the possibility of being deepened to the BCS after a few years, but only if no significant additional cost is required. If it is considered not practical or requires upfront additional investment in the well design, this deepening ability can be removed.

8.3.2. Perforation Strategy

The deep MMV wells may be perforated to monitor pressure in the Winnipegosis or possibly in the Cooking Lake. Since the perforation aims to establish communication with this formation with no specific performance target, the smallest gun may be used.

The two Deep MMV well designs schematics are given in Appendix C.

8.4. Shallow Groundwater MMV Wells

The BGWP and stratigraphy are not well known; therefore, there is a need for a pilot well prior to finalizing a completion zone. Either the pilot hole will then recompleted to the target interval or second well is be drilled to the chosen completion zone.

The shallow ground water wells should be of the simplest design. They aim to provide pressure and sampling capability of one shallow aquifer (to be determined) above the BGWP and below the vadose zone. Depending on the final depths and requirements, their design should follow either the deeper or the shallower groundwater wells drilled next to Radway 8-19.

Two shallow groundwater well types are considered (GWA and GWB); the final shallow groundwater wells may be a variation of one of these two types. Refer to the attached excel sheet in the appendix that has the suggested well design schematics for shallow ground water wells.

The two shallow groundwater MMV well designs schematics are given in Appendix D.

9. COMPLETION DESIGN

Requirement	CO_2 injection well	Deep MMV well	Shallow MMV Well
Objective	Inject CO_2	Monitor pressure and mircoseismic activity in the Winnepigosis to detect leakage of CO_2 or brine above the storage complex	Monitor water quality
Well Life	25+ years minimum injection period with expected 10 yrs monitoring, until well is abandoned	25+ years, until well is abandoned	25+ years, until well is abandoned
Tubing Size	3-1/2" to 4-1/2", pending number of injection wells bare carbon steel with premium gas tight connections	DWA: Only for pressure monitoring. Hence a well design with minimum 2-7/8" casing could suffice. No tubing completion is envisaged. DWB: Well design should have a tubing completion with geophones cemented outside the tubing and well access below tubing shoe for thru-tubing logging. J-55 or N-80	GWA: 1-1/4" GWB: none
Metallurgy	Wet CO_2 expected from pkr down. Thermal and pressure cycling throughout well life. Cold (-45 degC) surface temperatures in winter. Possible CO_2 flow wetted components are from pkr down to TD. Such components should be chrome and CRA coated.	Not expected that CO_2 would reach these wells	similar to water wells on 8-19

Wellhead	Suitable for full operating envelope and fluids. In 8-19: • rated to 30.5 MPa (5000 psi) pressure and 121 Deg C temperature. • temperature rating of the WH: LU (-46 Deg C to 121 Deg C) • Material classification: DD-NL • Performance requirement: PR2 • Product specification level § for primary components: PSL-3 § for secondary components: PSL-2	In all probability the WH will not be exposed to formation fluids. The well will not be used for injecting any fluid but may be used to collect bottom hole samples. WH specs could be relaxed from that for Injectors	Similar to water wells on 8-19.
Annulus isolation	Yes, pkr should be set no more than 15m above top perforation per ERCB Directive 56. Annular fluid should be compatible with pressure and temperature environment and in case CO_2 leaks to the backside Packer should be equipped with an on-off tool for easy tubing retrieval while killing the well on packer plug	Will not be exposed to extended production or injection. May need to protect casing from formation brine via a plug/gauge and inhibited fluid	No
DTS/DAS	Yes, on outside of main production casing	Possible but currently not under consideration	No
Casing Cathodic Protection	To be confirmed	To be confirmed	No
TR-SCSSV	Yes, depth currently under evaluation	No	No

Elastomer	Seek highest thermal stability, chemical resistance, and tensile strength in CO_2 environment (selection report from CRC pending)		
DHPG	Yes, permanent, above pkr, with nipple option to set a memory BHP in the event the permanent DHPG fails	Yes	No
Chemical Injection Port before the wellchoke	Yes, for possible hydrate inhibitor (outside of C&WI scope)	No	No
Sand Control	No, but still under evaluation	No	yes
Stimulation	Yes, but zeolites present in formation	No	No
Well surveillance and intervention activity	Thru-tbg logging, MPLT, CBL, USIT, VSP, tbg change-outs without having to remove the pkr or pump kill fluid into formation	Possible production with N_2 assisted lift. Geophone survey. CBL. USIT. Downhole water sampling. VSP. Possibility to be deepened to BCS after a few years, pending upfront investment costs	Data logger on battery. Periodic sampling for water chemistry analysis.

10. REFERENCES

[1]: *Quest Wells Conceptual Completion Design*, V. Hugonet, 07-3-ZW-7180-0003, November 2010

[2]: *7-11-59-20W4 H2S Release Rate Report*, V. Hugonet, July 2010

[3]: *15-29-60-21W4;12-14-60-21W4;10-6-60-20W4 H2S Release Rate Report*, V. Hugonet, July 2010

[4]: PT Note – Wells Start-up Strategy, V. Hugonet, May 2011

Appendix A – WFS Additional Data

Quest Well Functional Specification (WFS)					
Objective: Drill and complete all remaining CO2 injector and MMV wells with sound mechanical integrity meeting other associated well objectives				**Date:**	17/05/2011
Key Success Criteria: Goal Zero, Mechanical Integrity (including downhole instruments integrity), Injectivity (injector wells only), Data acquisition				**Revision:**	2
		DEEP MMV WELL (1 / CO2 Injector Well)		**Groundwater MMV WELL (3 / CO2 Injector Well)**	
Well Functional Specification	**CO2 INJECTOR WELL (3 min, 5 base, 10 max)**	***Well Type A (DWA): Pressure monitoring***	***Well Type B (DWB): Microseismic and pressure monitoring***	***Well Type A (GWA)***	***Well Type B (GWB)***
Reservoir Info					
Name of Zone	BCS	Winnipegosis (Cooking Lake as an alternative)	Winnipegosis (Cooking Lake as an alternative)	best aquifer zone (highest porosity and permeability zone) above the BGWP and below the vadose zone	best aquifer zone (highest porosity and permeability zone) above the BGWP and below the vadose zone
Zone Depth Top (MD/TVD)	2041m	1600m	1600m	20m	20m
Zone Depth Bottom (MD/TVD)	2087m	1615m	1615m	20-150m	20-150m
Expected Reservoir Pressure (min - max)	20.0 MPa (initial) - 32 MPa (final)	15.2 Mpa (initial)	15.2 Mpa (initial)	2,000 kPa	2,000 kPa
Reservoir Temperature (min - max)	15 degC (0 WHT) - 60 degC (initial)	56 degC	56 degC	5 degC - 25 degC	5 degC - 25 degC
Porosity	0.16	variable	variable	vairable	variable
Permeability	~150md	0.01 - (+10mD)	0.01 - (+10mD)	vairable	variable
NTG	90%	No data	No data	no data	no data
Fluid saturation	100% formation brine	100% formation brine	100% formation brine	100% fresh to brackish water	100% fresh to brackish water
Formation water density	1190 kg/m3 @ reservoir conditions	1187 kg/m3	1187 kg/m3	1015-1075 kg/m3	1015-1075 kg/m3
TDS	311,000 ppm NaCl	270,000 mg/l (+/- 10%)	270,000 mg/l (+/- 10%)	1,000-20,000 mg/l	1,000-20,000 mg/l
H2S	0	0	0	0	0
Fracture closure pressure gradient	16.8 kPa/m (BCS Fracture extension pressure is 20.6 kPa/m)	No data	No data	no data	no data
Pore pressure gradient	11.7 kPa/m (P= (SS depth - 330.6) / 0.08538	11.7 kPa/m	11.7 kPa/m	~10 kPa/m	~10 kPa/m
Well Data - *Note: The Hole size, casing grade and size are based on past experience. The WE must validate and approve the design in WTS (Wells Technical Specification)*					
Surface hole size	Conducive for subsequent casings and provide sufficient strength to prevent surface ground caving in. The water table is very shallow (confirm for every well site) and there is presence of shallow coal seams (confirm from PP for every well site). Gas tight cement recommended. 16" in 8-19 well	Only for pressure monitoring. Hence a well design with minimum 2 7/8" casing could suffice. No tubing completion is envisaged.	Well design should have a tubing completion with geophones cemented outside the tubing and well access below tubing shoe for though tubing logging	Similar to those already drilled on pad 8-19. 12-1/4" (see attached schematic). WE to advise whether further sliming down is feasible. Coring and logging requirement may influence final well design.	Similar to those already drilled on pad 8-19. 8-3/4" (see attached schematic). WE to advise whether further sliming down is feasible. Coring and logging requirement may influence final well design. It may be required to drill first pilot hole to determine the depth of the final well
Surface Casing (size, wt, grade, depth)	Surface casing to set not only to protect BGWP but also the potential gas bearing zone in white specs/Colorado. 8-19 well detail: 13-5/8", 107.15 kg/m, TN80SS BTC, shoe in Colorado (below BGWP)	WE to decide whether surface casing is required. Setting depth as per Injector well design if chosen to run surface casing.	WE to decide whether surface casing is required. Setting depth as per Injector well design if chosen to run surface casing.	Similar to those already drilled on pad 8-19. 9-5/8" steel casing (see attached schematic). Shoe above BGWP	Similar to those already drilled on pad 8-19. 6" PVC (see attached schematic). Shoe above BGWP

Well Functional Specification	CO2 INJECTOR WELL (3 min, 5 base, 10 max)	DEEP MMV WELL (1 / CO2 Injector Well)		Groundwater MMV WELL (3 / CO2 Injector Well)	
		Well Type A (DWA): Pressure monitoring	*Well Type B (DWB): Microseismic and pressure monitoring*	*Well Type A (GWA)*	*Well Type B (GWB)*
Intermediate hole size	Based on well design. Since intermediate casing will cover all the seals, a good in gauge hole is a must. 12-1/4" in 8-19	WE to advise whether intermediate casing string is required or not	WE to advise whether intermediate casing string is required or not	Similar to those already drilled on pad 8-19. 8-3/4".	Similar to those already drilled on pad 8-19. none
Intermediate Casing (size, wt, grade, depth)	Intermediate casing size to accommodate final production casing size and completion string. Premium gas tight connection preferred but WE to assure the chosen final casing grade, size and connection. 8-19 design: 9-5/8", 59.53 kg/m, TN80SS LTC, shoe in LMS	WE to advise whether intermediate casing string is required or not	WE to advise whether intermediate casing string is required or not	Similar to those already drilled on pad 8-19. 5-9/16" steel casing to possibly below BGWP.	Similar to those already drilled on pad 8-19. none
Main hole size	Based on well design. Main hole will cover the BC and LMS.In gauge hole a must. Coring (either 4" or 3"- PG to confirm for each well) may dictate under reaming to get to bigger hole size. 8-3/4" in 8-19	WE to advise	WE to advise	Similar to those already drilled on pad 8-19.	Similar to those already drilled on pad 8-19.
Main Casing (size, wt, grade, depth)	The zone covering the BCS and LMS must be of CR 22 CASING (till few meters inside the intermediate casing shoe) with premium connection (VAM casing with VAM top connection). Rest casing string is L-80 with potential premium gas tight connection. 8-19 design: 7", L80 LTC + 250m 22Cr-140, NK3SB - equipped with a DTS/DAS optic fibre strapped outside the casing	WE to advice. Preferred casing is TN-80SS.	WE to advice. Preferred casing is TN-80SS.	Similar to those already drilled on pad 8-19. OH completion with screens	Similar to those already drilled on pad 8-19. OH completion with screens
TOC's	surface. WE to decide on cement rheology behind respective casing strings and decide on placement strategy e.g. two stage vs. single stage cementing etc..	surface	surface	surface	surface
Additional Equipment	Possibly RTCI on outside of production casing	Possibly RTCI if completed to Cooking Lake back-up target formation	Possibly RTCI if completed to Cooking Lake back-up target formation	none	none
Deviation	Vertical	Vertical	Vertical	Vertical	Vertical
Evaluation					
Coring	Lotsberg salts in one CO2 injector well, Winnipegosis in one and up to two injector wells, Cooking Lake possibly in up to two injector wells, and BCS in all CO2 injector wells.	Winnipegosis and possibly Cooking Lake in at least one Deep MMV well	Winnipegosis and possibly Cooking Lake in at least one Deep MMV well	Shallow zones -similar to water wells on 8-19	Shallow zones -similar to water wells on 8-19
Core size	4" (3" OK for lotsberg salts and Winnepigosis).	? Note: Core size might dictate the hole size and hence the casing size. May be possible only for DWB type well. WE to advice	? Note: Core size might dictate the hole size and hence the casing size. May be possible only for DWB type well. WE to advice		
OH Logging	**Surface hole:** EMS-GR. **Intermediate hole:** Run1 = AIT-APS-2TLD-HNGS-PPC-EMS (GR, Neutron, Density, Calliper, Resistivity), Run2 = MSIP-2PPC-GR (GR, Sonic), Run3 = MDT – GR (Modular Formation Dynamic Tester, GR). **Main hole:** Run1 = ZAIT-GPIT-APS-TLD-PPC-HNGS (GR, Neutron, Density, Tri-axial Resistivity), Run2 = OBMI-GPIT-MSIP-2PPC-GR (Borehole Image, Sonic, GR), Run3 = wireline magnet for run 4, MRX-GR (NMR, GR), Run4 = MDT-GR (Modular Formation Dynamic Tester, GR)	**Surface hole:** EMS-GR. **Intermediate hole:** none. **Main hole:** Run1 = AIT-APS-2TLD-HNGS-PPC-EMS (GR, Neutron, Density, Calliper, Resistivity), Run2 = MSIP-2PPC-GR (GR, Sonic), Run3 = MDT – GR (Modular Formation Dynamic Tester, GR)	**Surface hole:** EMS-GR. **Intermediate hole:** none. **Main hole:** Run1 = AIT-APS-2TLD-HNGS-PPC-EMS (GR, Neutron, Density, Calliper, Resistivity), Run2 = MSIP-2PPC-GR (GR, Sonic), Run3 = MDT – GR (Modular Formation Dynamic Tester, GR)	**Surface hole:** EMS-GR. **Intermediate hole:** None. **Main hole:** EMS-GR	**Surface hole:** EMS-GR. **Intermediate hole:** None. **Main hole:** EMS-GR

Well Functional Specification	CO2 INJECTOR WELL (3 min, 5 base, 10 max)	DEEP MMV WELL (1 / CO2 Injector Well)		Groundwater MMV WELL (3 / CO2 Injector Well)	
		Well Type A (DWA): Pressure monitoring	*Well Type B (DWB): Microseismic and pressure monitoring*	*Well Type A (GWA)*	*Well Type B (GWB)*
Cased hole logging	USIT-CBI-VDL-GR-CCL+Temp in surface, intermediate and main casings from casing shoe to surface. Zero offset VSP in main hole.	USIT-CBI-VDL-GR-CCL+Temp in surface, intermediate and main casings from casing shoe to surface	USIT-CBI-VDL-GR-CCL+Temp in surface, intermediate and main casings from casing shoe to surface	none	none
Other requirements / needs	- Wells with a larger intermediate hole diameter that require MDT sampling in Winnipegosis and/or Cooking Lake WILL REQUIRE A SPECIAL MDT TOOL, DESIGNED FOR LARGE BOREHOLES. THE ONE TOOL IN THE WORLD CURRENTLY RESIDES IN MIDDLE EAST AND MAY NEED TO BE BROUGHT INTO THE COUNTRY FOR CO2 INJECTION WELLS #2 and #3! - Minifrac in top BCS	none	none	BGWP and stratigraphy not well known, so need a pilot well prior to finalizing a completion zone.	BGWP and stratigraphy not well known, so need a pilot well prior to finalizing a completion zone.
Well Destination					
Completed for immediate injection	May need to be SI for 2 months after initial CO2 injection has begun	N/A	N/A	N/A	N/A
Hooked up with rig on site	NO	NO	NO	NO	NO
Tested with rig on site	Initial testing may be with service rig on site	no	no	no	no
Future abandonment	Per regulations	Per regulations	Per regulations	option to keep pilot wells completed	option to keep pilot wells completed
Deepened in future	no	Possibility of being deepened to the BCS after a few years, pending costs and upfront investment	Possibility of being deepened to the BCS after a few years, pending costs and upfront investment	no	no
Other future requirements / needs	Dedicated Injector may be converted to an observation well during closure period	Possible upper recompletion to the Cooking Lake carbonate formation (back-up target for Winnepegosis)	Possible upper recompletion to the Cooking Lake carbonate formation (back-up target for Winnepegosis)	All pilot wells to be drilled first to allow time to analyze data and choose final completion zone. Then drill and complete all final GW wells.	All pilot wells to be drilled first to allow time to analyze data and choose final completion zone. Then drill and complete all final GW wells.
Fluids					
Surface Drilling Fluid	Water based mud	Water based mud	Water based mud	Water based mud	Water based mud
Intermediate Drilling Fluid	WE to advice. In 8-19 well: Oil based mud	WE to advice. In 8-19 well: Oil based mud	WE to advice. In 8-19 well: Oil based mud	Water based mud	Water based mud
Main Drilling Fluid	WE to advice. In 8-19 well: Oil based mud	WE to advice. In 8-19 well: Oil based mud	WE to advice. In 8-19 well: Oil based mud	Water based mud	Water based mud
Completion Fluid / Inhibitor	To be determined (fresh water preferred over KCl), filtered at 5 microns	WE/ CW&I to advice	WE/ CW&I to advice	Water base	Water base
Packer fluid / Inhibitor	inhibited brine or oil-based fluid. Possible N2 cushion to accommodate thermal contraction and expansion of fluid, which is currently under evaluation	N/A	N/A	N/A	N/A
Injection Fluid (CO2 Composition)	95-99% CO2, 0.15-0.02% CO, 0.01-0.00% N2, 4.27-0.68% H2, 0.57-0.09% CH4, 52 or less ppm H2O	N/A	N/A	N/A	N/A
Fluids Compatibility	BCS has limited clays. WE to discuss with PG/PP to design appropriate mud system. For opn: hydrate inhibitor and injection/formation fluids, acid and formation fluid and zeolites, annular fluid and P/T/leak	none	none	none	none

Well Functional Specification	CO2 INJECTOR WELL (3 min, 5 base, 10 max)	DEEP MMV WELL (1 / CO2 Injector Well)		Groundwater MMV WELL (3 / CO2 Injector Well)	
		Well Type A (DWA): Pressure monitoring	***Well Type B (DWB): Microseismic and pressure monitoring***	***Well Type A (GWA)***	***Well Type B (GWB)***
Completion					
Type (Single, dual, other) incl Initial Well Schematic	single	single	single	single	single
Tubing Size required for inflow performance (PI Curves)	3-1/2" to 4-1/2", pending number of injection wells	Only for pressure monitoring. Hence a well design with minimum 2 7/8" casing could suffice. No tubing completion is envisaged.	Well design should have a tubing completion with geophones cemented outside the tubing and well access below tubing shoe for though tubing logging	1-1/4"	none
Tubing (Bare, coated) Why?	bare carbon steel with premium gas tight connections	J-55 or N-80	J-55 or N-80	galvanized steel drop tube.	none
Metallurgy - Expected Well Conditions	Possible CO2 flow wetted components are from pkr down to TD. Such components should be chrome and CRA coated. Thermal and pressure cycling throughout well life.	not expected that CO2 would reach these wells	not expected that CO2 would reach these wells	similar to water wells on 8-19	similar to water wells on 8-19
Annulus isolation, nipple strategy for production isolation, setting depth	Pkr should be set no more than 15m above top perforation, nipple should be available to isolate BCS to swap tubing strings and to set a downhole gauge in. Annular fluid should be compatible with P&T environment and in case CO2 leaks to backside. Packer should be equipped with an on-off tool for easy tubing retrieval while killing the well on packer plug	Will not be exposed to extended production or injection. May need to protect casing from formation brine via a plug/gauge and inhibited fluid	Will not be exposed to extended production or injection. May need to protect casing from formation brine via a plug/gauge and inhibited fluid	none	none
Minimum completion ID / Location	CW&I	CW&I	CW&I	similar to water wells on 8-19	similar to water wells on 8-19
TRSSSV requirement - setting depth	~100-150m, final depth currently under evaluation	none	none	none	none
Special elastomer requirement (P, T, fluid)	HNBR - greater thermal stability, broader chemical resistance, greater tensile strength than that of a nitrile rubber	none	none	none	none
Special equipment requirements	surface filter spec'd to 5 microns or less, surface heat tracing, surface flow meter, chemical injection port upstream of wellchoke, DTS/DAS on outside of main production casing, casing cathodic protection (t.b.c.)	possibly DAS/DTS, casing cathodic protection, possibly RTCI	geophones, possibly DAS/DTS, casing cathodic protection, possibly RTCI	data logger on battery	data logger on battery
DHPG	permanent, just above the packer with cables running outside the tbg, with nipple option to set a memory BHP in the event permanent BHP fails.	yes	yes	none	none
Surface injection provision	For Tracer or Chemical Injection	no	no	no	no
Reservoir data requirement - functional specification for sensors - accuracy/compatibility, etc	standard	standard	standard	none	none
Artificial lift Requirements & design- ESP/Gas Lift Etc	none	none	none	none	none
Zonal isolation	will need to isolate BCS to be able to pull tbg in future	none	none	none	none
Sandface Requirement (prediction) - Selected Strategy	base case assumes none, currently under evaluation	none	none	5" pre-packed	4" PVC
Stimulation requirements (None/acid/frac/both)	acid compatible with zeolites	none	none	none	none
Wellhead	Suitable for full operating envelope and fluid. In 8-19: • rated till 30.5 MPa (5000 psi) pressure and 121 Deg C temperature. • temperature rating of the WH: LU (-46 Deg C to 121 Deg C) • Material classification: DD-NL • Performance requirement: PR2 • Product specification level for primary components: PSL-3 for secondary components: PSL-2	In all probability the WH will not be exposed to formation fluids. The well not be used for Injecting any fluid but may be used to collect bottom hole samples. WH specs could be relaxed than that for Injectors	In all probability the WH will not be exposed to formation fluids. The well not be used for Injecting any fluid but may be used to collect bottom hole samples. WH specs could be relaxed than that for Injectors	similar to water wells on 8-19.	similar to water wells on 8-19.

Well Functional Specification	CO2 INJECTOR WELL (3 min, 5 base, 10 max)	DEEP MMV WELL (1 / CO2 Injector Well)		Groundwater MMV WELL (3 / CO2 Injector Well)	
		Well Type A (DWA): Pressure monitoring	*Well Type B (DWB): Microseismic and pressure monitoring*	*Well Type A (GWA)*	*Well Type B (GWB)*
Perforating					
Perforation Interval (MD/TVD)	~30m, currently under evaluation	currently under evaluation, for P monitoring purposes only	currently under evaluation, for P monitoring purposes only	N/A	N/A
Special measurements, eg pressure measurement while	P gauge should be included in perforating gun BHA	currently under evaluation	currently under evaluation	N/A	N/A
Gun Type	Preferably TCP. Connex/Stim Gun currently under evaluation	currently under evaluation, small	currently under evaluation, small	N/A	N/A
Gun Size	currently under evaluation (exp: 4 1/2")	currently under evaluation	currently under evaluation	N/A	N/A
SPF	In 8-19: 5 spf, or highest density achievable in each run, currently under evaluation	currently under evaluation	currently under evaluation	N/A	N/A
Perf length, diameter	Deep penetration with big hole size	currently under evaluation	currently under evaluation	N/A	N/A
overbalance / under balance	dynamic underbalanced	currently under evaluation	currently under evaluation	N/A	N/A
Gauge requirements (Fast gauge,etc)	standard	none	none	N/A	N/A
Well Start-Up Requirements					
Artificial Lift	none	none	none	none	none
Injection test, duration, data requirements	~18 hours (but plan for 24-hr operations), using fresh water filtered to 5 microns or less, 100-300 L/m, similar to Radway 8-19 injection test, memory BHP gauge and MPLT	possible production test followed by produced water reinjection to prove pressure communication across a large AOR	possible production test followed by produced water reinjection to prove pressure communication across a large AOR	none	none
Other - Bean Up Rate	currently under evaluation	none	none	none	none
Concept (sep test, abandon)	injection test to prove injectivity, SI till CO2 start-up, Conditoning by displacing wells prior to start-up to CO2 using a CO2 truck, then slowly open pipeline-well choke to ramp-up. Specific wells strategy start-up document available (07-3-ZW-7180-0013)	need to be able to produce with N2 assisted lift	need to be able to produce with N2 assisted lift	none	none
Additional Well Information - Operating Envelope					
Well Life (Years) Max /likely/minimum	50/25/25 (till abandonment)	50/25/26	50/25/26	35/25/27	35/25/27
Steady State Flow Rates CO2 (min - exp - max)	175,000 m3/d - 351,000 m3/d - 900,000 m3/d	N/A	N/A	N/A	N/A
Steady State WHP (min - exp - max)	0.1 MPa (atmospheric) - 5 MPa - 14 MPa	0.1 MPa (atmospheric) - 7 Mpa	0.1 MPa (atmospheric) - 7 Mpa	N/A	N/A
Steady State WHT (min - max)	0 degC (winter) - 18 degC (summer) .	-45 degC (winter ambient) - +35 degC (summer ambient)	-45 degC (winter ambient) - +35 degC (summer ambient)	N/A	N/A
Minimum tbg temperature (JT effect during transient flow)	(-10) degC, currently under evaluation	N/A	N/A	N/A	N/A
Expected Shut-in WHP / WHT	3.5-11.0 MPa / ambient temperatures (-45 degC in winter to 35 degC in summer)	-45 degC (winter ambient) - +35 degC (summer ambient)	-45 degC (winter ambient) - +35 degC (summer ambient)	-45 degC (winter ambient) - +35 degC (summer ambient)	-45 degC (winter ambient) - +35 degC (summer ambient)
Any special load case that needs to be run for Wellcat	adequate pkr envelope and design considering the thermal contraction of the tbg during injection. Casing burst and collapse pressure rating and confirm that it is within the casing failure envelope under all operating condition. (can wellcat model annular fluid designs for us too - noting change in P/T from SI to SS flow?)	None	None	None	None
Well Kill Strategy	set plug in packer to isolate BCS and not have to inject kill fluid. If not feasible, kill the well with sand plug + 5 micron fresh water or gel (to be confimed).			NA. Sub hydrostatic well	NA. Sub hydrostatic well
Deposits	Surface filter to be spec'd to 5 microns or less to be located at each wellpad to prevent pipeline debris from entering and plugging formation.	none	none	none	none

Well Functional Specification	CO2 INJECTOR WELL (3 min, 5 base, 10 max)	DEEP MMV WELL (1 / CO2 Injector Well)		Groundwater MMV WELL (3 / CO2 Injector Well)	
		Well Type A (DWA): Pressure monitoring	*Well Type B (DWB): Microseismic and pressure monitoring*	*Well Type A (GWA)*	*Well Type B (GWB)*
Well Entries					
Workover frequency and requirements	currently under evaluation. Assume initially one well every alternate year. Minimum: once every 5 yrs for CBL and Corrosion logging	none expected	none expected	none expected	none expected
Required well & reservoir surveillance activities. Specify Largest Tool OD for Future Surveillance/Lifecycle issues	thru-tbg logging, MPLT, CBL, USIT, VSP, and tubing changeouts	CBL, USIT, downhole water sampling	CBL, USIT, geophone survey, downhole water sampling	data logger on battery, water sample, pump change	data logger on battery, water sample, pump change
Planned well maintenance activities	CW&I to advice	CW&I to advice	CW&I to advice	CW&I to advice	CW&I to advice
Miscellaneous					
Special objectives	To remain an effective injector with no degradation in well integrity	To monitor P in the Winnipegosis. To monitor for leak outside of storage complex within Winnipegosis.	To monitor P in the Winnipegosis. To monitor for leak outside of storage complex within Winnipegosis.	P and brine composition monitoring	P and brine composition monitoring
Possible new technology application					
Lessons learnt from similar wells	Radway 8-19. Refer to 8-19 AAR report. KCl may be incompatible with BCS brine and lead to solid dropout. BCS has a very limited of swellable clay, therefore fresh water preferred over KCl for well operations	none	none	none	none
QA/QC - identify any special requirements	Cementing, running instrument string behind casing and ensuring good cement job with cement to surface. Refer to 8-19 AAR				

APPENDIX B – CO2 injector well schematic (from Radway 8-19)

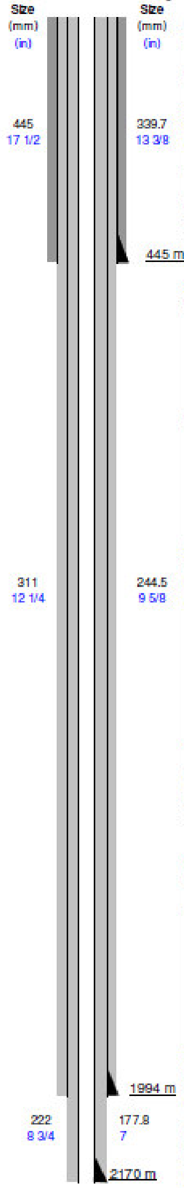
Shell Quest Radway

Well Name:	SCL Radway 8-19-59-20W4	Surface Location:	Lsd 8-19-59-20W4	Drilling Eng.:	Pedro Aleman
Well Licence:	Pending	BH Location:	Lsd 8-19-59-20W4	Phone:	403-691-3065
Type of Well:	Vertical Injection CO2	Ground Elev.:	640.1 m (estimated)	Cell:	403-807-7038
AFE Number:	Pending	KB Elev.:	646.1 m (estimated)	Rig #:	Nabors 78
		Directional Plan:	Vertical	Date Modified:	16-Jun-2010

Formation	Depth (m KB)
Lea Park	206
Colorado	328
Surface Casing	445
2nd White Specks	465
Base Fish Scales	534
Viking	589
Joli Fou	603
Mannville	622
Glauconite SS	754
Ostracod Zone	764
Base Cretaceous - Top Devonian	833
Calmar	833
Nisku	**845**
Ireton	885
Duvernay	1085
Cooking Lake	1154
Beaverhill Lake	1250
Moberly	1264
Christina	1338
Calmut	1379
Firebag	1402
Slave Point	1442
Watt Mountain/1stRed	1459
Muskeg	1470
Prairie Salt	1470
Keg River/Winnipegosis	**1603**
Contact Rapids	1624
Ernestina Lake	1702
Top Upper Lotsberg	1718
Base Upper Lotsberg	1803
Top Lower Lotsberg	1869
Base Lower Salt	1893
Base Devonian/Top Cambrian	1916
MCS - Middle Cambrian Shales	**1943**
Top LMS - Lower Marine Sand	1983
Intermediate Casing	1994
Top BCS * - Basal Cambrian Sand	2057
Precambrian	2095
TD	**2170**

* Zone of interest

Well Schematic



Engineering Information

SURFACE

Risk:	Lost circulation in shallow hole, mud rings, sloughing/ tight hole Potential flows
Evaluation:	Borehole caliper log only. Req'd logging suite to be run at int. depth. Cased: Sonic Scanner - APS - GR
Survey:	Surveys every 150m, surface to section TD
Surface Casing:	13-3/8" (339.7mm) x 107.15kg/m, TN80SS, BTC, R3, SMLS
Cement Program:	Class G to surface: SurfCem 1700+0.50% LCB-1000+1.00% CaCl2
Pressure Test:	15 MPa (BOP rating)
Formation Inegrity Test:	Not required below Surface Casing shoe

Interval 1: 0-445m
Gel Slurry
1020 - 1100 kg/m3

INTERMEDIATE

Risk:	**Potential for significant lost circulation in Nisku** Potential for HC from 555m to TD Sloughing/ tight hole, minor coal, chert pebbles in Viking & Manville Salt/evaporate beds below Slave Point **Potential for Kick in Keg River/Winnipegosis** **Potential for up to 3.5% H2S in Nisku and Ireton formations** (zero flow potential)
Evaluation:	Wellsite geologist SC shoe to TD Gas detector from SC shoe to TD GWD from ~ 1600m (to ID core point) Open: PEX (HNGS-APS)+Dual Density+EMS+Rt Scanner Sonic Scanner, (P,S&Anisotropy)-PPC-GR MDT-GR (Optional) Cased: USIT-CBT-GR-CCL-Temp (0-1982m) CBL (pressure pass) prior to drill-out
Survey:	Surveys every 150m, surface casing shoe to section TD.
Inermediate Casing:	Intermediate casing depth is to be 10m into the LMS 9-5/8" (244.5mm) x 59.53kg/m, TN80SS, LTC, R3, SMLS
Cement Program:	Two-stage program with stage collar and ECP set above Nisku. STAGE 1 PREFLUSH 1: Base Oil STAGE 1 PREFLUSH 2: Superaweep L + 20.0 L / m3 Nowflush 12C STAGE 1 FILL CEMENT: SpectraCem G + 0.80 % LCB-1000 + 0.90 % FL-5 + 0.90 % R-3 STAGE 1 TAIL CEMENT: PozzFume G + 0.10 % R-3 + 0.10 % SPC-12000 + 0.50 % A-11 + 0.50 % CD-32 +0.80 % LCB-1000 + 0.90 % FL-5 STAGE 2 PREFLUSH 1: Base Oil STAGE 2 PREFLUSH 2: Superaweep L + 20.0 L / m3 Nowflush 12C STAGE 2 PREFLUSH 2: Superaweep L + 20.0 L / m3 Nowflush 12C
Pressure Test:	25 Mpa Maximum surface pressure limited to the lesser of frac pressure test,
Coring:	18m from the top of MCS
Formation Inegrity Test:	Not required below Intermediate Casing shoe

Interval 2: 445-Keg River
Invert mud
1050 - 1080 kg/m3

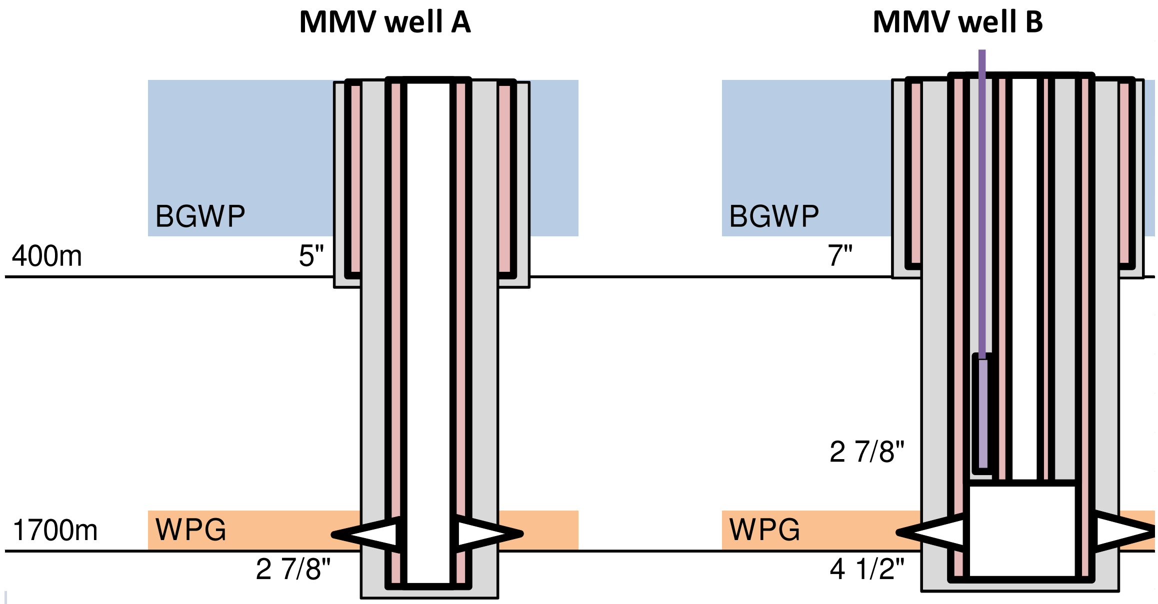
MAIN

Risk:	Granite (quartz, feldspar) in Precambrian Interbedded shales in Cambrian Sands
Evaluation:	Core from immediately below IC shoe into the Precambrian Side wall core may be required +/- six MDT's prior to running liner Open: PEX (HNGS-APS-TLD) + Rt Scanner CMR or MRX-GR Sonic Scanner (P,S&Anisotropy)-PPC-OBMI-GPIT-GR MDT-GR Cased: USIT-CBT-GR-CCL-Temp(0-TD) VSP(zero-offset)-GR(0-TD)~125 level
Survey:	Survey at TD
Pressure Test:	30 Mpa
Injection Casing/ Casing:	7" (177.8mm) / 250m of 38.69kg/m, 22CR-140, NK3SB, R2 + 38.69kg/m, L80, LTC, R3, SMLS to surface
Formation:	98% CO_2, 2% H & CO, < 20 ppm water
Reservoir Pressure:	21 MPa
Coring:	54m from the last 10m of LMS to 3m into the PreCambrian
Cement Program:	PREFLUSH 1: HC Sweep + 48.20 % Barite PREFLUSH 2: Supersweep L + 20.0 L / m3 Nowflush 12C + 28.00 % Barite FILL CEMENT: SpectraCem G + 0.90 % FL-5 + 1.00 % R-3 TAIL CEMENT:PozzFume G + 0.10 % R-3 + 0.10 % SPC-12000 + 0.50 % A-11 + 0.50 % CD-32 + 0.90 % FL-5

Interval 3: Keg River-Int TD
Invert mud
1150 - 1180 kg/m3

Invert system
1050 - 1100 kg/m^2

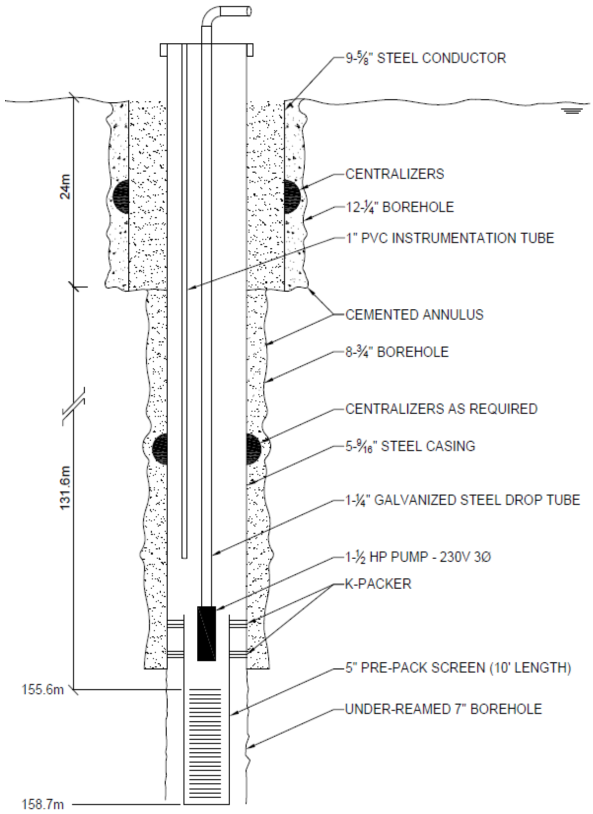
APPENDIX C – Deep MMV well design schematics



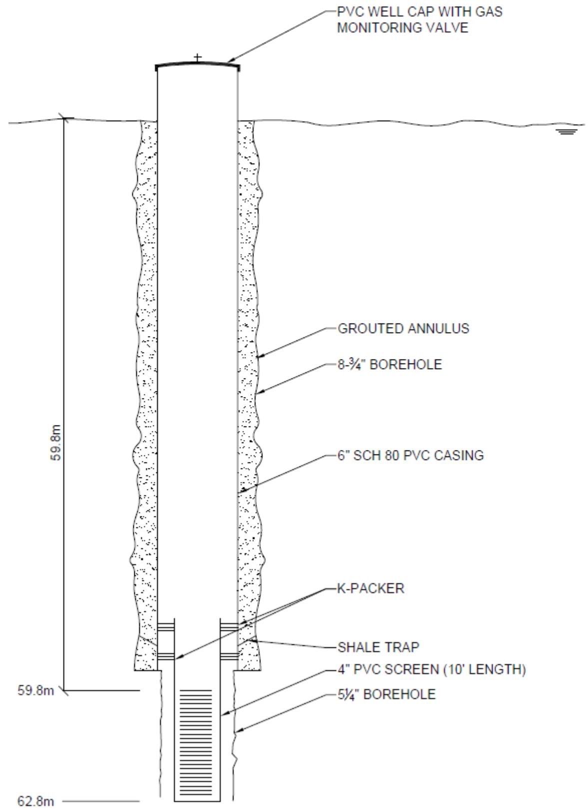
	MMV well A	MMV well B
Strings	5" surface casing 2 7/8" cemented main casing	7" surface casing 4 1/2" main casing 2 7/8" cemented tubing
Objective:	Pressure monitoring in WPG Borehole access (2 7/8")	Pressure monitoring in WPG Cemented geophones (~20m) Borehole access (2 7/8")

APPENDIX D – Shallow groundwater well design schematics

Ground water well A (GWA)



Ground water well B (GWB)



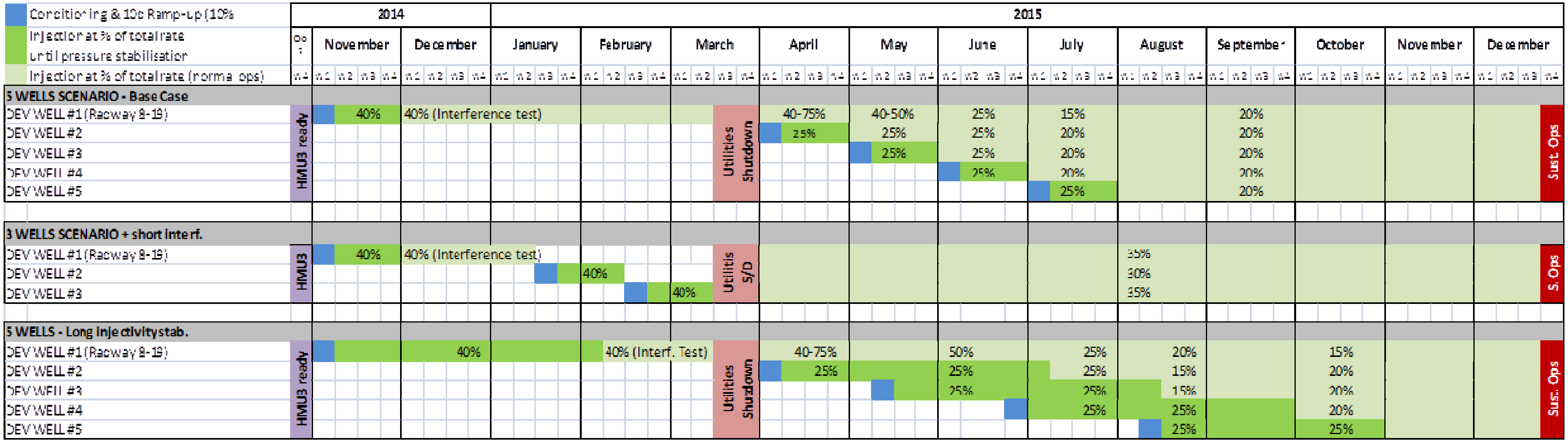
APPENDIX E – Wells Start-Up Strategy (from Ref. 4)

The staggered start-up of the three Hydrogen Manufacturing Units (HMU) in 2014-2015 provides the opportunity to test the integrated capture, transport and injection system prior to the contractual steady state injection deadline of end 2015. The wells start-up strategy aims to achieve several technical objectives to reduce some residual surface and subsurface uncertainties and should support early achievement of the three tests that define "Commercial Operations" and initiate government funding. The wells start-up strategy base case scenario consists of the following:

- Prior to start-up the well will be displaced from water to CO2 with a CO2 truck
- Injection will start as soon as HMU3 is online (Q4 2014) 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
- If stable injectivity requires a longer time than anticipated when starting up an injector (>25 days), the following 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 the beginning of Q4 2015, irrespective of the pressures stabilising or a response noted at adjacent injectors

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.

The following schematic presents the base case start-up scenario, as well as an optmistic and pessimistic case.



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 started at the same rate (40% of total rate) subsequently while the remaining capacity will be spread over the wells previously started up. Injection in the start-up well is to take priority and injection in wells that are already commissioned should never continue at the expense of risking system instabilities that could trip the start-up sequence.

Note: After the Q2 2015 turnaround, the first well should also be ramped up over a few days from 40% to 70% because it will not have been tested at that rate before. Alternatively, the additional 30% could be vented until the third well is started.

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.

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. Consequently, since all wells need to be started-up and injecting at stable pressure before Sustained Operations, the interference test will be kept to a minimum and the start-up of the following injectors will be staggered.

It should be noted that after the Q2 2015 turnaround, the wells that have been already started-up may be shut-in if more capacity is required in other wells. The injection rates (in %) after start-up, in light green, are therefore indicative only and may be changed during the start-up finalisation.