UNIVERSITY OF CALGARY

Energy & Environmental Systems EES iseee

Energy and Environmental Systems Group
Institute for Sustainable Energy, Environment and Economy (ISEEE)

Well Design and Well Integrity

WABAMUN AREA CO_2 SEQUESTRATION PROJECT (WASP)

Author

Runar Nygaard

Rev.	Date	Description	Prepared by
1	January 4, 2010	Well Design and Well Integrity	Runar Nygaard

Table of Contents

INTRODUCTION........5
BACKGROUND........5
DISCUSSION........5
1. WELL DESIGN AND POTENTIAL LEAKAGE PATHS........5
2. EFFECT OF CO_2 INJECTION ON WELL CONSTRUCTION MATERIALS........7
2.1 Cement........7
2.2 Oil Well Cements........8
2.3 CO_2 Effect on Portland Cements........11
2.4 CO_2 Corrosion on Tubulars and Steel Components........17
2.5 Mechanical Effects on Wellbore........18
3. WELL INJECTION DESIGN........19
3.1 Geological Description of Well Location........19
3.2 Casing Design........21
3.3 Cementing Design........22
3.4 Completion Design........23
4. INJECTION WELL COST ESTIMATE........24
5. ABANDONMENT OF WELLS........27
6. EVALUATION OF EXISTING WELLS IN NISKU........29
7. CONCLUSIONS........35
8. REFERENCES........36
Appendix A........38

List of Tables

Table 1: Regular Portland cement briefly described the different classes as specified in API Specification 10A and ASTM Specification C150. 9

Table 2: Brief description of special cements (Meyer, 2008; Schlumberger, 2009; Halliburton, 2009). 10

Table 3: Materials of construction (MOC) for CO_2 injection wells based on US experience (Meyer, 2008). 18

Table 4: Well cost model WASP project injection well. 24

Table 5: Well cost results WASP project injection well. 25

Table 6: Tubular and cementing costs for a vertical well. 26

Table 7: Drilled and abandoned wells in focus area. 33

Table 8: Drilled, cased and abandoned wells. 34

List of Figures

Figure 1: Example of possible leakage paths for CO_2 in a cased wellbore (Celia et al, 2004). 6

Figure 2: Well design and abandonment of wells in the Wabamun Lake area (ERCB, 2007; Watson and Bachu, 2007). 7

Figure 3: Illustration of the chemical reactions zones in cement casing. First Zone $Ca(OH)_2$ dissolves and $CaCO^3$ forms. Second Zone $CaCO_3$ dissolves when $Ca(OH)_2$ is spent (Kutchko et al, 2007). 12

Figure 4: Rate of carbonation for Portland cement from laboratory tests, Barlet-Gouédard et al (2006). 13

Figure 5: Carbonation depth (mm) versus time (days) at 50˚C (Kutchko et al, 2008). 14

Figure 6: Test of Class H Portland cement in CO_2 saturated fluid (Kutchko et al, 2008). 15

Figure 7: Validation of CO_2 durability of different cement systems (Barlet-Gouedard et al, 2008). 16

Figure 8: Photograph of samples recovered from the 49-6 well in Texas. It shows the casing (left), gray cement with a dark ring adjacent to the casing, 5 cm core of gray cement, gray cement with an orange alteration zone in contact with a zone of fragmented shale, and the shale country rock (Carey et al, 2007). 16

Figure 9: Well design for vertical injection well. 20

Figure 10: Vertical and least horizontal stress and pore pressure gradients (Michael et al, 2008). 21

Figure 11: Carbonation depth estimated from laboratory tests after 100 year. 23

Figure 12: Drilling time for vertical well estimated based on three reference wells in the area. 25

Figure 13: Schematic of using metal alloy plug to seal and abandon production zone (Canitron, 2008). 28

Figure 14: Suggested abandonment method for CO_2 injection wells. 29

Figure 15: Age distribution of wells drilled through Nisku in the study area. Gray wells are drilled and abandoned, white wells are drilled and cased wells. 30

Figure 16: Flow chart for identifying wells which are candidates for re-entering and conduct workover operations to improve leakage integrity. 31

Figure 17: Outline of the study area where horizontal lines are Ranges West of 5 and Vertical squares are Townships. The highlighted area is the focus area where all 27 wells where studied in detailed. Twelve additional wells where randomly selected (indicated in green). 32

Figure 18: Spatial distribution of all wells penetrating Nisku in the study area. 34

INTRODUCTION

BACKGROUND

To successfully inject CO_2 into the subsurface to mitigate green house gases in the atmosphere, the CO_2 must to be trapped in the subsurface and not be allowed to leak to the surface or to potable water sources above the injection horizon. Potential leakage can occur through several different mechanisms, including natural occurrences or along wells. To avoid leakage from injection wells, the integrity of the wells must be maintained during the injection period and for as long as free CO_2 exists in the injection horizon. In addition to injection wells, monitoring wells will most likely be required to observe the plume movement and possible leakage. The Environmental Protection Agency (EPA) in the United States has stated that its goal is to be able to account for 99% of the CO_2 injected (NETL, 2009).

The experience from more than 100 CO_2 enhanced oil recovery (EOR) projects over the last 30 years has shown that CO_2 can be successfully transported and injected into a reservoir in the subsurface (Moritis, G. 2008). CO_2 EOR projects, along with wells drilled in H_2S-rich environments and high-temperature geothermal projects, have delivered developments for improved well designs and materials, such as improved tubing and types of cement.

However for CO_2 sequestration, the time aspect is very different than for typical EOR projects. The CO_2 should be safely stored and prevented from rising to the surface or to formations higher up in the geological succession in the foreseeable future. That has been translated loosely into the 1000 year well integrity problem.

In addition to the new injection and monitoring wells, saline aquifers are seen as attractive storage sites for CO_2, but are often located in areas where oil production and a large number of wells exist. In the province of Alberta alone, there already exists more than 350,000 wells and around 15,000 are drilled each year (ERCB, 2009). The integrity of existing wells that penetrate the capping formation also needs to be addressed to avoid CO_2 leakage.

The study’s first objective was to identify a wellbore design that will effectively secure long-term well integrity for new CO_2 injection and monitoring wells. The second objective was to evaluate the leakage risk of existing wells within the Wabamun CO_2 storage project area.

DISCUSSION

1. WELL DESIGN AND POTENTIAL LEAKAGE PATHS

After CO_2 is injected into the subsurface, the CO_2 plume may move upwards or sideways because of pressure difference and buoyancy. Wells are an obvious pathway for CO_2 to escape the reservoir formation. There are several possible pathways (see Figure 1). CO_2 can leak along the interfaces between the different materials, such as the steel casing cement interface (Figure 1a), cement plug steel casing (Figure 1b), or rock cement interface (Figure 1f). Leakage can also occur through cement (Figure 1c) or fractures in the cement (Figure 1d and 1e). In addition to these smaller scale features, leakage can occur when wells are only cemented over a short interval or the cement sheet is not uniformly covering the entire circumference of the well. Casing corrosion can also lead to casing failure and large leakage pathways.

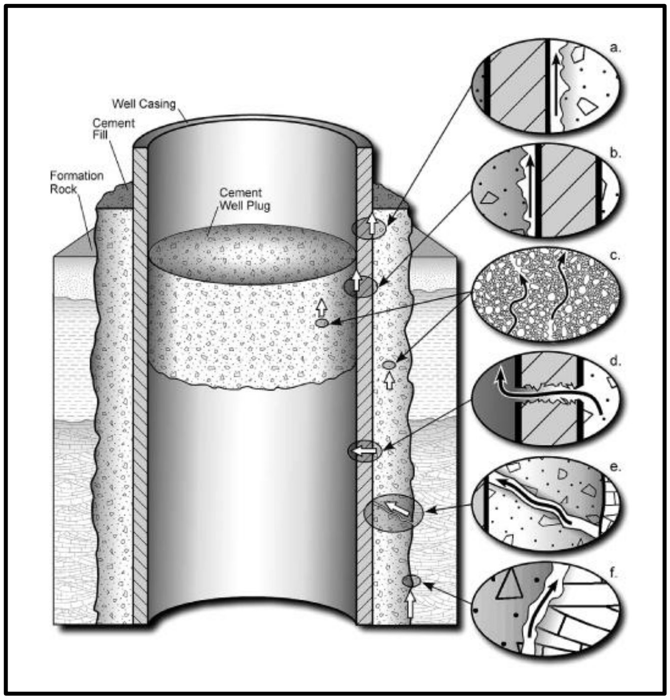


Figure 1: Example of possible leakage paths for CO_2 in a cased wellbore (Celia et al, 2004).

Different types of wells and the status of a well gives rise to different leakage scenarios. For instance, in the case of an exploration well the main section of the hole is drilled but not cased. After drilling, the well is abandoned with cement plugs set across the porous formations (Figure 2). The main leakage path is caused by problems that occurred while the cement plugs were set, or the plugs are missing. Cement plugs are quite thick and therefore a properly set plug provides a thick barrier for the CO_2 to penetrate. A cased well has cement in an annulus between the formation and the steel casing, which protects the outside of the casing. The cement sheet for cased wells is thin compared to abandonment plugs, since the thickness of the cement is limited to the annular space between the casing and the rock formation. Cased wells may also have casing exposed directly to the formation because the casing is not always cemented to the surface. When cased wells are abandoned (i.e., production or injection wells), a cement plug is set over the producing interval or a bridge plug is used with or without a cement plug over top. The cased well with a short cement interval inside the casing represents another possible leakage path (Figure 2).

Several recent studies have investigated the integrity of wells around the world. They have identified that out of 316,000 wells analyzed in Alberta—4.6% have leaks. Gas migration occurred in 0.6% of the wells and surface casing vent flow (SCVF) in 3.9% (Watson and Bachu, 2007). In a subset of 20,500 wells, 15% leaked with drilled and abandoned wells making up 0.5% and cased wells 14.5%. The reported leakage occurred mainly from formations shallower than those suitable for CO_2 injection and related to thermal operations. In the Norwegian sector of the North Sea, between 13 and 19% of the production wells experienced leakage, while 37 to 41% of the injectors experienced leakage (Randhol and Carlsen, 2008; NPA, 2008). Further, estimates from the Gulf of Mexico indicate that a significant portion of wells have sustained casing pressure, which is believed to be caused by gas flow through cement matrix (Crow, 2006). In a study of the K-12B gas field in the Dutch sector of the North Sea where CO_2 is injected, 5% of tubulars where degraded because of pitting corrosion (Mulders, 2006).

The main observation from these studies is that cased wells as more prone to leakage than drilled and abandoned wells, and injection wells are more prone to leakage than producing wells.

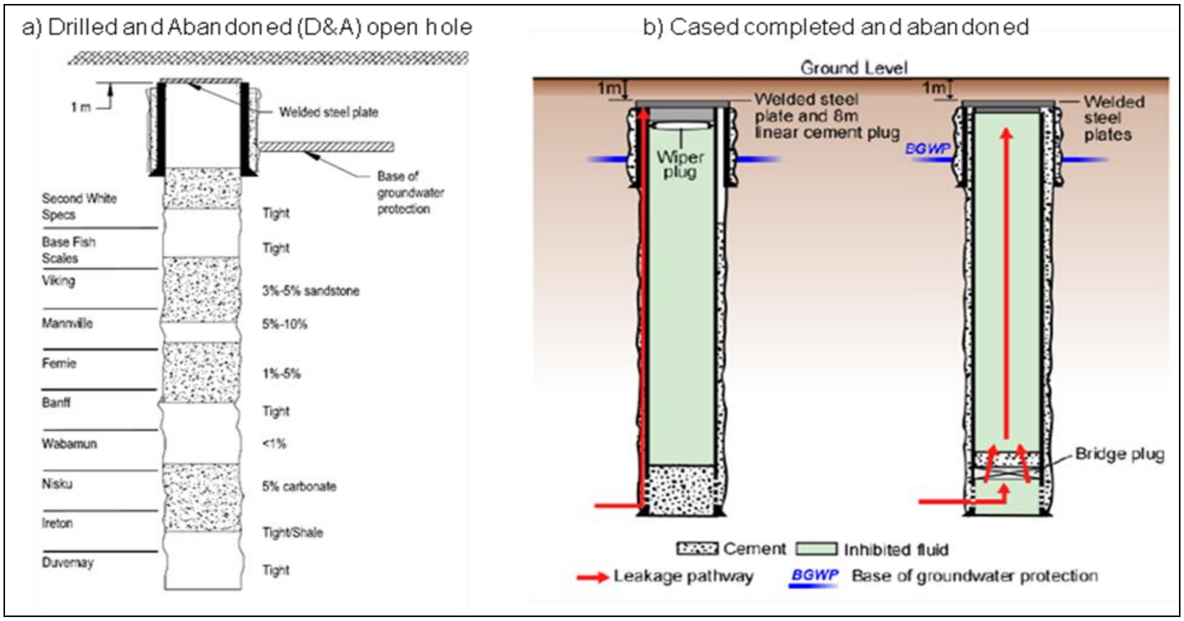


Figure 2: Well design and abandonment of wells in the Wabamun Lake area (ERCB, 2007; Watson and Bachu, 2007).

2. EFFECT OF CO_2 INJECTION ON WELL CONSTRUCTION MATERIALS

CO_2 can react with the different materials used to construct a well. When it reacts with cement, the cement's strength is reduced and its permeability increased. CO_2 can also corrode steel. This chapter summarizes the effect CO_2 has on the various materials used in well construction and how these problems can be mitigated.

2.1 Cement

Cementing can be divided into two broad categories, primary and remedial. Primary cementing is used during regular drilling operations to support the casing and stop fluid movement outside the casing (zonal isolation). Cement also protects the casing from corrosion and loads in deeper zones, prevents blow outs and seals off thief and lost circulation zones. The cement sheath is the first barrier around a wellbore that the CO_2 will encounter.

The well construction process only allows one chance to design and install a primary cementing system. A less than optimal cement sheath can significantly reduce an injection well's value by not preventing CO_2 from leaking into shallower formations. To solve the problem, the injection process must be interrupted to perform costly remedial cementing treatments. In a worst case scenario, failure of the cement sheath can result in the total loss of a well.

During the drilling phase of a well, the cement sheath must withstand the continuous impact of the drill string, particularly with directional wells. During well completion when the drilling fluid is replaced by a relatively lightweight completion fluid, the negative pressure differential can cause de-bonding at the casing cement and/or cement formation interfaces. The cement sheath must withstand the stresses caused by the perforating operation and resist cracking from the extreme pressure created by the hydraulic fracturing operation.

The key to good cementing is good operational practices. The two most important factors to good cementing is to centralize the casing by frequently mounting centralizers on the casing and to reciprocate and/or rotate the casing during the cementing operation. It is important to run the casing at a speed that will not fracture the formation. After the casing is in place, common cement failures occur in one of two ways: poor primary cementing or cement failure after setting. Poor primary cementing occurs because a thick mud filter cake lines the hole and prevents good formation bonding. Proper displacement techniques, such as pre-flush, spacers and cement plugs, may not be sufficient because the conventional cement is not the best displacement fluid. Secondly, gas can invade the cement while it sets. During gelling and prior to complete hydration, conventional cement slurry actually loses its ability to transmit hydrostatic pressure to the formation and fluids from the formation migrate freely into the cement. This forms channels that can create future gas leaks. Cement failure after setting occur from mechanical shock from pipe tripping, expansion of the casing and compression of the cement during pressure testing, or expansion and contraction of the pipe due to cycles in injection pressure and temperature.

2.2 Oil Well Cements

Oil well cement consists of clinker material containing various calcium silicates and iron and aluminum compounds. Regular cement used in the petroleum industry is Portland cement, which contains at least two-thirds calcium silicates. The clinker is made from a blend of burned (calcined) limestone and clay. The clinker is ground to a powder and a small amount of gypsum ($CaSO_4*H_20$) is often added to increase strength and slow setting time. The American Petroleum Institute (API) has classified different cement types (denoted from A to H) for different temperature and pressure (depth) ranges. Today, Types H and G are the most common. The different cement types are briefly described in Table 1. Some of these types have variations for increased sulfate resistance. In addition to the regular Portland cement, oil well cement slurry contains different additives that change the density, viscosity, filtration properties and setting time of the cement.

Additives are used with API Portland cements to modify the properties of the cement slurry. They fall into five main categories.

1) Density reduction materials: reduces cement density and prevents fracturing of the formation. Examples are Bentonite and other clay minerals, such as Pozzolans and nitrogen (used in foam cement).
2) Weight materials: increases the slurry’s density. Examples are Barite, Hematite and sand.
3) Viscosifiers: reduces the viscosity of the cement slurry and prevent fracturing while the cement slurry is pumped. Examples are sodium chloride and calcium lignosulfonate (lignosulfonate works also as retarder).
4) Filtration control: prevents leakage of the cement slurry into porous and permeable formations by using caustic soda or calcium hydroxide.
5) Accelerators and retarders: modifies the time it takes to harden the cement (setting time). Accelerators reduce the setting time (i.e., the time before the cement develops strength and seals off fluids). Examples of accelerators are calcium chloride, sodium chloride and potassium chloride. Retarders increase the setting time and are mainly based on organic compounds, such as calcium lignosulfonate or cellulose.

Table 1: Regular Portland cement briefly described the different classes as specified in API Specification 10A and ASTM Specification C150.

API Class (ASTM type)	Description
Class A (Type I)	Portland cement for situation where no special properties are required. Class A cement is available only in ordinary (O) grade. Applicable for depth from surface down to 6000 ft. (1830 m) depth.
Class B (Type II)	Portland cement with sulfate-resistant properties to prevent deterioration of the cement from sulfate attack in the formation water. Processing additions may be used in the manufacture of the cement, provided the additives meet the requirements of ASTM C465. Available in both moderate sulfate-resistant (MSR) and high sulfate-resistant (HSR) grades. Applicable for depth from surface to 6000 ft. (1830 m) depth.
Class C (Type III)	Class C cement is used when high early strength and/or sulfate resistance is required. Processing additions may be used in the manufacture of the cement, provided the additives meet the requirements of ASTM C465. This product is intended for use when conditions require early high strength. Available in ordinary (O), moderate sulfate-resistant (MSR), and high sulfate-resistant (HSR) grades. The depth range is 6000 to 10,000 ft. (1830 to 3050 m).
Class G	No additions other than calcium sulfate or water, or both. Shall be blended with the clinker during manufacture of Class G cement. Class G is a basic well-cement and available in moderate sulfate-resistant (MSR) and high sulfate-resistant (HSR) grades. Depth range is 10,000 to 14,000 ft. (3050 to 4270 m). Class G is ground to a finer particle size than Class H.
Class H	No additions other than calcium sulfate or water, or both. Shall be blended with the clinker during manufacture of Class H cement. This product is for use as basic well cement and is available in moderate sulfate-resistant (MSR) and high sulfate-resistant (HSR) grades. Surface to 8,000 ft. (2440 m).

In addition to the API or ASTM classified cement, various special types of cement materials can be used for cementing wells (see Table 2). Many of these special cements are developed for specific applications. Some are a dry blend of API cements with a few additives, while others are cements containing other chemical characteristics. The composition of these cements is controlled and often kept confidential by the supplier.

Table 2: Brief description of special cements (Meyer, 2008; Schlumberger, 2009; Halliburton, 2009).

Name	Description
Pozzolanic-Portland Cement	Pozzolanic materials are often dry blended with Portland cements to produce lightweight (low density) slurries for well cementing applications. Pozzolanic materials includes any natural or industrial siliceous or silica-aluminous material, which in combination with lime and water, produces strength-developing insoluble compounds similar to those formed from hydration of Portland cement. The most common sources of natural pozzolanic materials are volcanic materials and diatomaceous earths (from silica fossils). Artificial pozzolanic materials are usually obtained as an industrial byproduct, or natural materials such as clays, shales and certain siliceous rocks. Adding pozzolanic materials to API or ASTM cements reduces permeability and minimizes chemical attack from some types of corrosive formation waters.
Gypsum Cement	Gypsum cement is blended cement composed of API Class A, C, G or H cement and the hemi-hydrate form of gypsum ($CaSO_4$ $0.5H_2O$). In practice, the term “gypsum cements” normally indicates blends containing 20% or more gypsum. Gypsum cements are commonly used in low temperature applications because gypsum cement set rapidly, has early high strength, and has positive expansion (approximately 2.0%). Cement with high gypsum content has increased ductility and acid solubility, and because of these characteristics, is not considered appropriate for CO_2 service.
Microfine Cement	Microfine cements are composed of very finely ground cements of either sulfate-resisting Portland cements, Portland cement blends with ground granulated blast furnace slag, or alkali-activated ground granulated blast furnace slag. Microfine cements have an average size of 4 to 6 microns, and a maximum particle size of 15 microns, which make them harden fast and penetrate small fractures. An important application is to repair casing leaks in squeeze operations, particularly tight leaks that are inaccessible by conventional cement slurries because of penetrability.
Expanding Cements	Expansive cements are available primarily for improving the bond of cement to pipe and formation. Expansion can also be used to compensate for shrinkage in neat Portland cement.
Calcium Aluminate Cement	High-alumina cement (HAC) or calcium aluminate cements (CAC) are used for very low and very high temperature ranges. Several high alumina cements have been developed with alumina contents of 35 to 90%. The setting time for calcium aluminate cement is controlled by the composition and no materials are added during grinding. These cements can be accelerated or retarded to fit individual well conditions, however, the retardation characteristics differ from those of Portland cements. The addition of Portland cement to this cement causes very rapid hardening; therefore, they must be stored separately. Calcium aluminate phosphate cement blended with a few additives produce cements that are highly resistant to the corrosive conditions found in wells exposed to naturally occurring wet CO_2 gas or CO_2 injection wells.

Name	Description
ThermaLock™	ThermaLock cement is specially formulated calcium phosphate cement that is both CO_2 and acid resistant. This cement is well suited for high temperature geothermal wells. ThermaLock has been laboratory tested and proven at temperatures as low as 60°C and as high as 371°C.
Latex Cement	Latex cement is a blend of API Class A, G or H with polymer (latex) added. A well distributed latex film may protect the cement from chemical attack in some corrosive conditions, such as formation waters containing carbonic acid. Latex also makes the hardened cement elasticity and improves the bonding strength and filtration control of the cement slurry.
Resin or Plastic Cements	Resin and plastic cements are specialty materials used for selectively plugging open holes, squeezing perforations, and the primary cement for waste disposal wells, especially in highly aggressive acidic environments. A unique property of these cements is their capability to be squeezed under applied pressure into permeable zones to form a seal within the formation.
Sorel Cement	Sorel cement is magnesium oxychloride cement used as a temporary plugging material for well cementing. The cement is made by mixing powdered magnesium oxide with a concentrated solution of magnesium chloride. Sorel cements have been used to cement wells at very high temperatures (up to 750°C).
EverCRETE™ CO_2	EverCRETE CO_2 is marketed as CO_2-resistant cement that can be applied for carbon capture and storage, as well as CO_2 enhanced oil recovery projects. EverCRETE cement has proven highly resistant to CO_2 attack during laboratory tests, including wet supercritical CO_2 and water saturated with CO_2 environments under downhole conditions. It can be used both for standard primary cementing operations, as well as plugging and abandoning existing wells.

2.3 CO_2 Effect on Portland Cements

Since the cement sheath in a wellbore will be the first material exposed to the injected CO_2 in the subsurface, the stability of the cement in a CO_2 rich environment has drawn a lot of attention. When CO_2 is in contact with regular Portland cement, the latter is not chemically stable. CO_2 gas in water will reach equilibrium with the water through the following reaction:

$$CO_2 + H_2O = HCO_3^- + H^+ = CO_3^{2-} + 2H^+$$

Regular Portland-based cements contain $CO(OH)_2$, which reacts with CO_2 when water is present to form solid calcium carbonate through the following chemical reaction:

$$Ca(OH)_2 + CO_3^{2-} + 2H^+ = CaCO_3 + 2H_2O$$

This process is named cement carbonation. Even if this process alters the composition of the cement, it leads to lower porosity in the cement because calcium carbonate has a higher molar volume (36.9 cm^3) than $Ca(OH)_2$ (33.6 cm^3) (Shen and Pye, 1989). For cement sheath integrity, this reaction actually improves the cement's properties and the carbonation is therefore a self healing mechanism in the carbonate. Bachu and Bennion (2008) performed two sets of flow experiments for 90 days at 60°C on a Class G cemented annulus. First set of experiments used CO_2 saturated brines and the second set used ethane instead of CO_2. The CO_2 flushed sample had the lowest permeability, which was probably caused by the carbonation.

In a CO_2 sequestration project, the supply of CO_2 around the wellbore will continue the carbonation process as long as $Ca(OH)_2$ is present in the cement. The calcium carbonate is also soluble with the CO_2, even though it is more stable than $Ca(OH)_2$. Experiments by Kutchko et al (2007) showed that when all $Ca(OH)_2$ has reacted in the carbonation process, the pH will drop significantly (Zone 1 on Figure 3). When the pH drops, more of the CO_2 will react with water and form HCO_3- (Zone 2 on Figure 3). The abundance of HCO_3- will react with the calcium carbonate to form calcium (II) carbonate, which is soluble in water and can move out of the cement matrix through diffusion (Kutchko et al, 2007). The final reaction that occurs in Zone 3 (close to the cement surface) is calcium silicate hydrate reacting with H_2CO_3 to form calcium carbonate ($CaCO_3$) according to the following chemical reaction:

$$3\ H_2CO_3 + Ca_3Si_2O_7 * 4H_2O = 3\ CaCO_3 + 2\ SiO_2 * H_2O + 3\ H_2O$$

The volume of calcium silicate hydrate is larger than the calcium carbonate and this reaction will increase the porosity of the cement in Zone 3, which is the closest to the reservoir formation containing the CO_2.

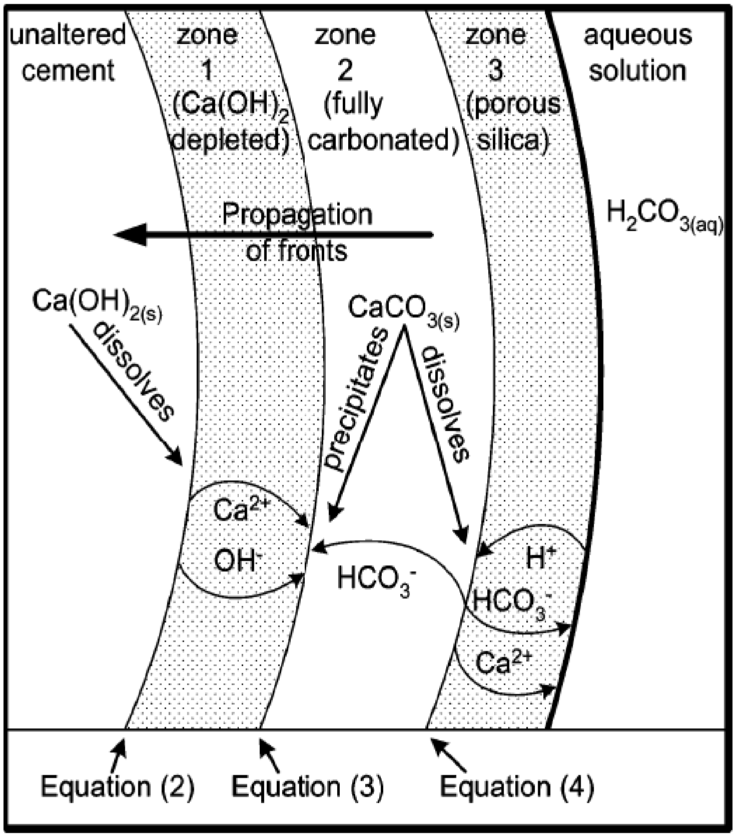


Figure 3: Illustration of the chemical reactions zones in cement casing. First Zone $Ca(OH)_2$ dissolves and $CaCO^3$ forms. Second Zone $CaCO_3$ dissolves when $Ca(OH)_2$ is spent (Kutchko et al, 2007).

The effect of CO_2 alterations on Portland cement containing calcium silicate hydrates and calcium hydroxide was studied in both laboratory experiments and field tests. Barlet-Gouedard et al (2006) tested a Portland cement API Class G in both CO_2 saturated water and supercritical CO_2 at 90°C. The rate that carbonation occurred is shown in Figure 4. For wet supercritical CO_2 conditions, the rate of the alteration front can be calculated based on:

$$\text{Depth of } CO_2 \text{ alteration front (mm)} = 0.26 \times (\text{time in hours})^{1/2}$$

For example, the carbonation process will have penetrated 10 mm into the sample after 60 days or 100 mm after 17 years. Kutchko et al (2008) performed similar experiments on a Class H Portland cement slurry at 50°C with a CO_2 saturated brine (Figure 5 and 6). The results for CO_2 supercritical brine at 50°C showed a slower alteration front within the cement. The curve fit estimating alteration depth based on Kutchko et al (2008) results for supercritical CO_2, which is shown as:

$$\text{Depth of } CO_2 \text{ alteration front (mm)} = 0.016 \times (\text{time in days})^{1/2}$$

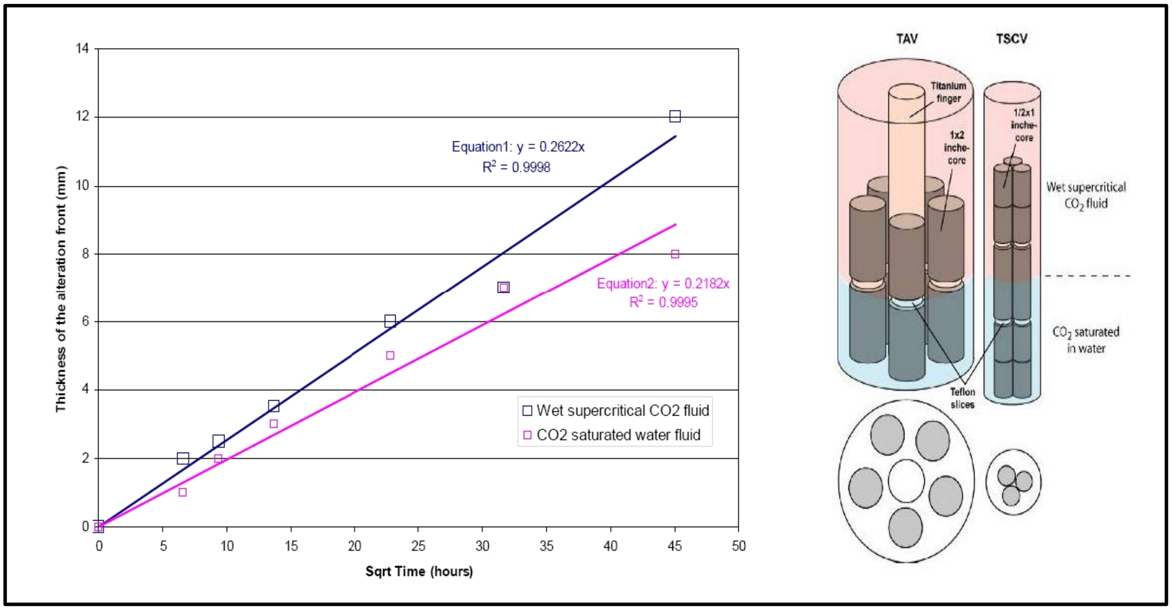


Figure 4: Rate of carbonation for Portland cement from laboratory tests, Barlet-Gouédard et al (2006).

In this example, the carbonation process will have penetrated 10 mm after 1000 years and 100 mm after 100,000 years. The main difference between these experimental procedures, excluding the cement type and temperature, is that Barlet-Gouedarad et al (2006) used de-ionized water while Kutchko et al (2008) used 0.17 molar NaCl brine. Barlet-Gouedard et al (2008) performed additional experiments with a 4 molar NaCl brine to simulate downhole formation water conditions. It was observed that the carbonation rate was a tenth of the carbonation rate found in the 2006 experiments and the results where more in agreement with Kutchko et al (2008) and field experiments. The experiments clearly documented that increased salinity reduces the carbonation rate. Another difference between these experiments is that Kutchko et al (2008) used neat cement (API Class H), while Barlet-Gouedard et al (2006, 2008) used cement blends. Kutchko et al (2008) tested cement samples with bentonite additives. This sample showed a much higher degree of carbonation, similar to Barlet-Gouedard et al (2006). Another interesting observation is that any fracture or weakness in the cemented sample showed a higher degree of carbonation.

Milestone et al (1986) showed that increasing the content of silicate in the cement and a reduction of $Ca(OH)_2$ content resulted in a deeper carbonation front in the tested cement specimen, and increased the porosity in the cement at a faster rate. However, a 20% silica content is often needed in the cement mixture to get below the API recommended 0.01 mD permeability threshold. Silica also increases the compressive strength of the cement. High-strength silicate-rich cements samples that were exposed to CO_2 for 10 months lost 60% of their volume, while the samples without silicate lost 35% (Milestone et al, 1990). Even though a reduction in silica enhances the CO_2 resistance of the cement, it is difficult to obtain for Portland-based cement mixtures. The carbonation for cement attacked by supercritical CO_2 was also increased by an increase in the partial pressure of the CO_2 and an elevated temperature (Onan, 1984).

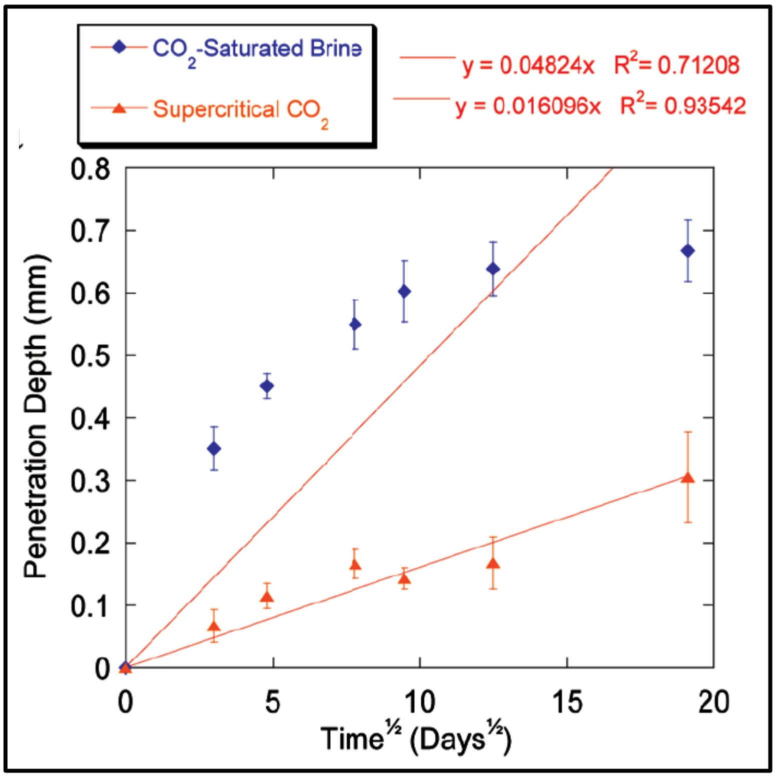


Figure 5: Carbonation depth (mm) versus time (days) at 50˚C (Kutchko et al, 2008).

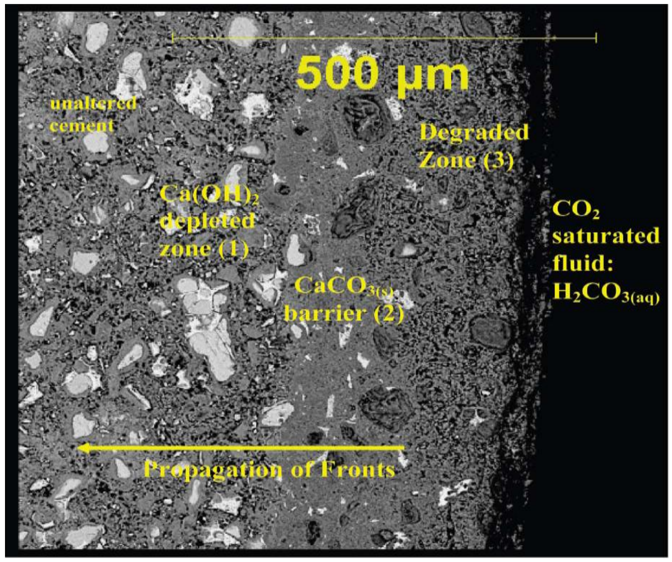
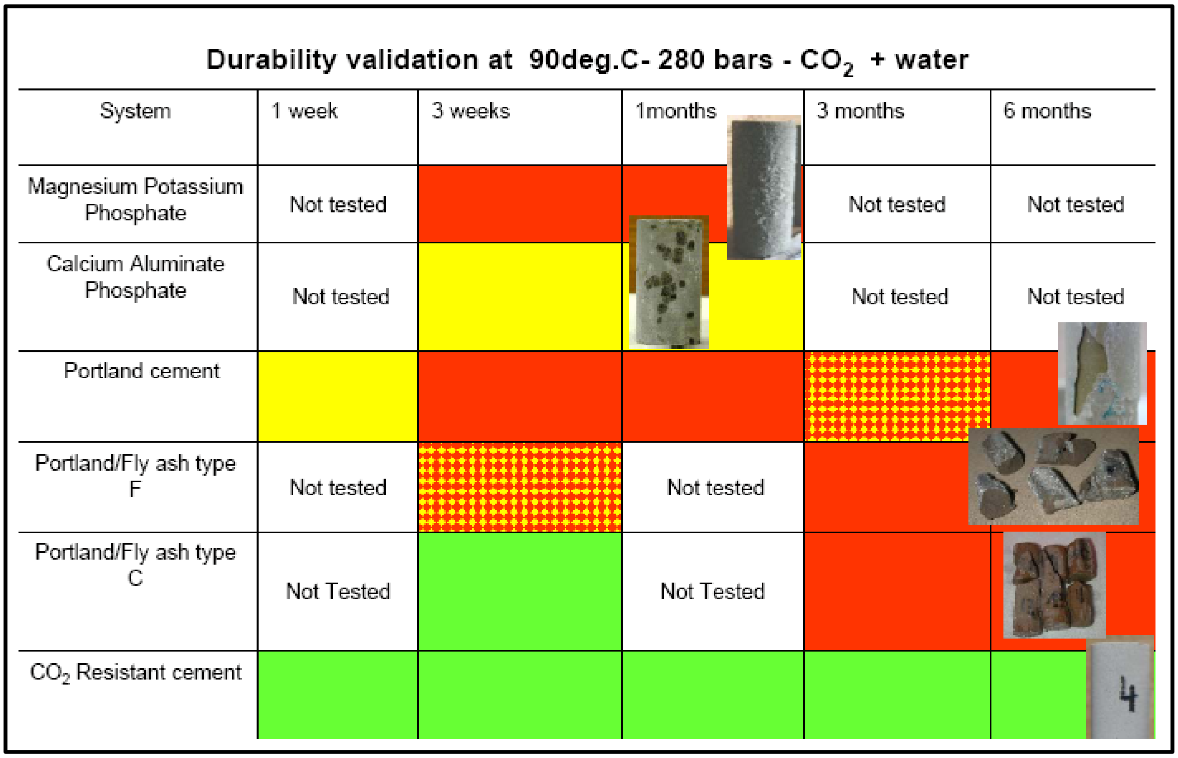


Figure 6: Test of Class H Portland cement in CO_2 saturated fluid (Kutchko et al, 2008).

Barlet-Gouedard et al (2008) summarized their CO_2 durability experiments for different cement mixtures (see Figure 7). The results indicate that only the Schlumberger proprietary EverCrete™ is stable towards long-term CO_2 attack. The Thermalock™ from Halliburton was not part of the study.

In the SACROC unit in West Texas, a 240 m thick limestone reservoir at 2000 m deep with a temperature of 54°C and a pressure of 18 MPa has been flooded with CO_2 (Carey et al, 2007). The 49-6 well was drilled in 1950 and cemented with a Type A Portland cement without additives. The well went on production and experienced CO_2 breakthrough in 1975. It continued to be a producer for the next 10 years and was converted to an injection well for the next 7 years. During its active years, a total of 110,000 tonnes of CO_2 passed through the well. Samples of the casing, cement and adjacent caprock were taken from about 4 to 6 m above the caprock reservoir contact (Figure 8). The cement was found to be partly carbonated. The cement that was in contact with the shale rock was heavily carbonated. The cement close to the casing had pure carbonate like a vein filling. No obvious proof of direct CO_2 interaction with the shale was found. The permeability of the cement was found to be higher than pristine Portland cement. SEM imaging showed that $CaCO_3$ had precipitated in the void spaces.



Durability validation at 90deg.C- 280 bars - CO_2 + water

System	1 week	3 weeks	1months	3 months	6 months
Magnesium Potassium Phosphate	Not tested			Not tested	Not tested
Calcium Aluminate Phosphate	Not tested			Not tested	Not tested
Portland cement					
Portland/Fly ash type F	Not tested		Not tested		
Portland/Fly ash type C	Not Tested		Not Tested		
CO_2 Resistant cement					

Figure 7: Validation of CO_2 durability of different cement systems (Barlet-Gouedard et al, 2008).

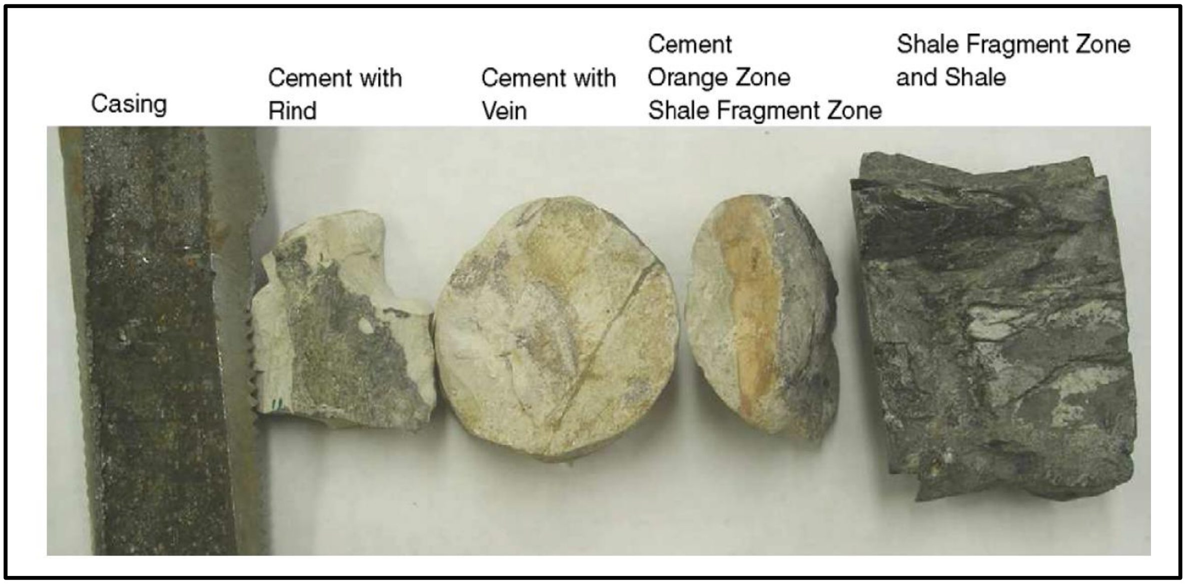


Figure 8: Photograph of samples recovered from the 49-6 well in Texas. It shows the casing (left), gray cement with a dark ring adjacent to the casing, 5 cm core of gray cement, gray cement with an orange alteration zone in contact with a zone of fragmented shale, and the shale country rock (Carey et al, 2007).

It was generally concluded that the structural integrity of the Portland cement was adequate to prevent a significant transport of fluids. However, it is believed that CO_2 had migrated along the cement casing and cement shale interfaces for some time.

Shen and Pye (1989) examined geothermal wells and the carbonation by CO_2 of Class G cement. To stabilize Portland cement at high temperatures, silica flour was added. In geothermal well cements there is little or no $Ca(OH)_2$, so the C-S-H phases can be attacked directly by the CO_2. The CO_2 content for the wells were 12,200 ppm CO_2 (0.20 mol/kg), while the temperatures were in the range of ~ 200 to 300°C. They found that the carbonation was dependant on temperature, CO_2 concentration and location. Both carbonated and uncarbonated cement had fractures and fissures, which was probably caused by the thermal cycles in the well. Shen and Pye (1989) found that the number of shutdowns correlated with the increase in permeability. This fits with the observed fractures, where sharp changes in temperature led to the deformation in the cement and likely caused the fracturing of the cement. There was no correlation evident between the extent of the carbonation and porosity. However, temperature and the amount of calcium carbonate formed in the cement due to CO_2 showed a clear relationship.

Krilov et al (2000) studied wells exposed to 180°C and 22% CO_2. After 15 years of service, the performance of the wells dropped. Debris was found downhole in the wells. Krilov et al (2000) found CO_2 to be the main reason of the degradation. They performed tests at simulated downhole conditions and concluded that the loss of compressive strength and cement integrity was caused by high temperature and CO_2 concentration.

2.4 CO_2 Corrosion on Tubulars and Steel Components

Steel products in wellheads, casing and completion strings are subjected to corrosion in an acidic environment. The main corrosion reaction in carbon steel is:

$$Fe\ (s) + 2H^{+}\ (aq) \rightarrow Fe^{2+}\ (aq) + H_2\ (g)$$

where the solid iron dissolves into iron ions in solution to create a corroded surface on the steel. The basic requirement for this reaction to occur is water. When CO_2 is used for enhanced oil recovery, most likely water alternated with CO_2 gas (WAG) or recycled CO_2 is injected. In capture and sequestration projects, dry CO_2 (with CO_2 purity above 95%) will be injected and therefore, corrosion problems are not expected to be any more severe for CO_2 storage as compared to regular CO_2 EOR operations.

For the last 35 years, wellhead and completion tubing materials for CO_2 enhanced oil recovery projects has been developed in the US based on industry practice. The materials used for the different components are summarized in Table 3 (Meyer, 2008). In the United States, the oil and gas industry operates over 13,000 CO_2 EOR wells, has over 3500 miles of high-pressure CO_2 pipelines, injects over 600 million tons of CO_2 (11 trillion standard cubic feet) and produces about 245,000 barrels of oil per day from CO_2 EOR projects. Meyer (2008) summarizes the technological advancement as follows:

- Corrosion resistant materials, such as stainless and alloy steels (e.g., 316 SS, nickel, Monel, CRA), for piping and metal component trim. Use of corrosion protection of the casing strings via impressed and passive currents and chemically inhibited (e.g., oxygen, biocide, corrosion inhibitor) fluid in the casing tubing annulus.
- Use of special procedures for handling and installing production tubing to provide tight seals between adjacent tubing joints and eliminate coating or liner damage.

- Use of tubing and casing leak detection methods and repair techniques, using both resin and cement squeeze technologies. Also the insertion of fiberglass and steel liners.
- Formulation and implementation of criteria unique to well sites in or near populated areas, incorporating fencing, monitoring and atmospheric dispersion monitoring elements to protect public safety. Current industry experience shows that when these technologies and practices are used, EOR operators can expect wellbore integrity at levels equivalent to those seen for conventional oil and gas wells.

Table 3: Materials of construction (MOC) for CO_2 injection wells based on US experience (Meyer, 2008).

Component	MOC
Upstream Metering & Piping Runs	316 SS, Fiberglass
Christmas Tree (Trim)	316 SS, Nickel, Monel
Valve Packing and Seals	Teflon, Nylon
Wellhead (Trim)	316 SS, Nickel, Monel
Tubing Hanger	316 SS, Incoloy,
Tubing	GRE lined carbon steel, IPC carbon steel, CRA
Tubing Joint Seals	Seal ring (GRE), Coated threads and collars (IPC)
ON/OFF Tool, Profile Nipple	Nickel plated wetted parts, 316 SS
Packers	Internally coated hardened rubber of 80-90 durometer strength (Buna-N), Nickel plated wetted parts

2.5 Mechanical Effects on Wellbore

Randhol and Cerasi (2009) provide a recent review of mechanical factors that can influence the integrity of the wellbore cement sheath. They pointed out that fractures in the cement sheath can occur from de-bonding of cement and fracturing at the rock formation interface, which is generally caused by water activity in the shale and cement. If the filter cake or mud is not properly removed, channeling of the cement can occur. Normal cement tends to shrink if no additives are used to prevent it. This creates poor bonding between the cement and the casing or formation, as well as fractures within the cement itself.

During injection, changes in temperature and pressure will lead to stress exposure in the injection wells, which conventional Class G cement is not suited for (Pedersen et al, 2006). Potential deformation caused by uplift of the reservoir during injection may rise to deformation loads on casing and cement and possible fractures (Orlic et al, 2008). Adding elastomeric and fibre materials to the cement can improve the amount of deformation that cements can tolerate (Randhol and Cerasi, 2009).

3. WELL INJECTION DESIGN

3.1 Geological Description of Well Location

The well design in this report is based on injecting CO_2 into the dolomitic Nisku formation. Currently there has been no decision made as to a specific location, so the information described below is for a generic well within the study area. The top of the Nisku formation is assumed to be 1890 m deep. The depth to the top of the Nisku formation in the Wabamun Lake area ranges from less than 1600 m in the northeast to deeper than 2200 m in the southwest. The formation is on average 72 m thick, typically ranging from approximately 60 to 100 m, but thinning to less than 40 m in the northwest. It is capped by the Calmar formation shale ranging in thickness from 5 to 15 m. The caprock is overlain by the upper Devonian-Lower Cretaceous aquifers (Figure 9). Ultimately, the thickness of the Colorado and Lea Park aquitards above these aquifers will act as a final barrier to any vertically migrating CO_2 (Figure 9). However, the Devonian Lower Cretaceous aquifer system contains several oil and gas fields in the area. Therefore, to prevent CO_2 migrating towards existing production, it is important to determine if the Calmar may be breached during or after injection.

The reported Sv gradient in the area is 23 kPa/m and the average fracture gradient in the Wabamun Lake study area is 20 kPa/m (Figure 10). This translates to a maximum allowable injection pressure of 33.4 MPa at 1890 m, which is 90% of the fracturing pressure at that depth and is lower than the area average of 37 MPa for well depths from 1850 to 1900 m (ERCB Directive 051, 1994).

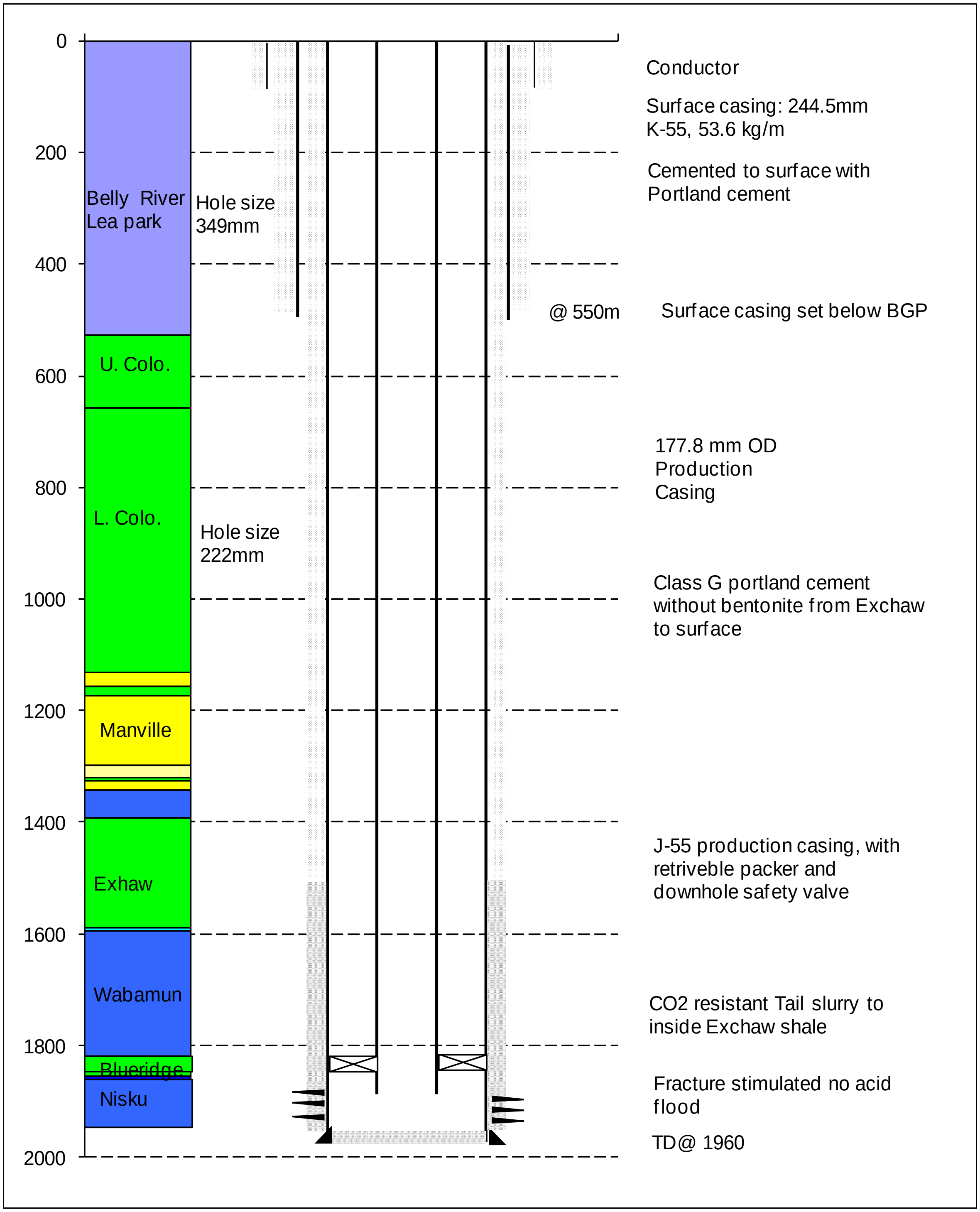


Figure 9: Well design for vertical injection well.

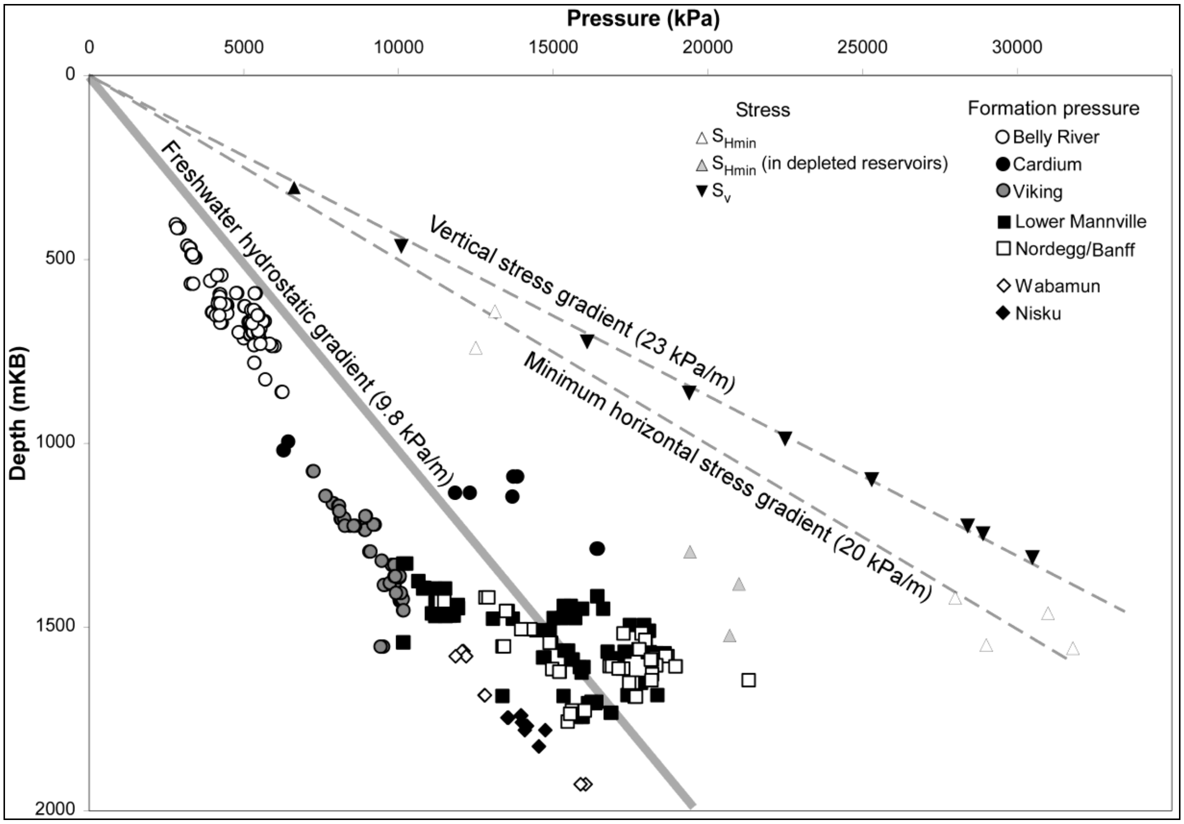


Figure 10: Vertical and least horizontal stress and pore pressure gradients (Michael et al, 2008).

3.2 Casing Design

A CO_2 injection well in Alberta is classified as a Class III well. Class III wells are used for the injection of hydrocarbons, inert gases, CO_2 and acid gases for the purpose of storage or enhancing oil recovery from a reservoir matrix (ERCB directive 051, 1994). A Class III well is required to have cement across usable ground water, but there is no requirement to have surface casing below base ground water protection. The base ground water protection is below 450 m for the area, so if the surface casing is set below the water protection zone a conductor is required. The Nisku formation has below normal hydrostatic gradient, but some of the formation higher up is pressurized in the area (Figure 10). The maximum pressure recorded in the Nordegg/Banff is 19,000 KPa (when disregarding the one outlying point in Figure 10). For a fluid pressure gradient of 11.8 KPa/m, the surface casing depth has to be 400 m for a 1960 m deep well to satisfy ERCB directive #8. With surface casing, the well can be drilled to TD with a mud gradient between 11 and 18 KPa/m. However, exact mud weight cannot be determined before the final well location is set.

In the selected casing design, the surface casing is set below the ground water protection area. The rationale for setting the surface casing is to get a second leakage barrier from the wellbore through both casing strings. Setting the surface casing this deep requires a conductor to be set (Figure 9). The production casing will be cemented and perforated down to TD.

The casing material selection strategy is to avoid having the casing come in contact with wet CO_2. To prevent CO_2 from coming in contact with the casing, completion tubulars, chemical inhibitors in the completion fluid used to fill the annular space, and cement outside the casing will be used as barriers. This approach prevents the casing from being in direct contact with the injected CO_2, except in the perforated Nisku interval, where regular carbon steel will be sufficient.

3.3 Cementing Design

For the current well design, there are two or three possible cementing operations. First, the conductor may be cemented in place, then the surface casing is cemented from a depth of around 550 m to the surface. The production casing is cemented from the injection horizon to the surface. Cementing operations should have verified returns. To reduce to possibility of escape paths, all annular spaces between the casing strings and the hole annulus should be cemented.

It is unlikely that the surface casing will come in contact with carbon acid (H_2CO_3) from the deeper part of the injection formation, since there are several porous formations where the CO_2 will escape (e.g., Wabamun Group), therefore specialty cement is not required. The carbonation reaction is temperature dependant and also reduces the carbonation rate at surface casing depths. Cement slurry consisting of API Class G cement may include an accelerator for reducing the setting time for the low temperature of the surface casing. Typically 2% calcium chloride is added to the cement slurry as an accelerator. Good cementing practices are most important for getting good leak-free cement. Therefore operational practices should include a pre-flush with water, add scratchers or wipers on the casing, add centralizers for each stand (three joints) of casing and rotate the casing string during the injection of cement. And lastly, the cement should return to the surface.

During the injection phase, cement will only encounter dry CO_2. However after the injection phase and all the free CO_2 around the wellbore is dissolved in the brine, the wellbore will be attacked by carbonic acid (H_2CO_3). The carbonic acid will only attack the reservoir portion of the production casing, therefore special consideration of CO_2 cement needs only to be considered for the reservoir, primary seal and a safety zone above the reservoir. If the pressured CO_2 escapes along the cement and through the caprock, it will bleed off into the permeable and low-pressured Wabamun Group. Therefore as mentioned above, special CO_2 cement should not be necessary for anything shallower than the Wabamun Group.

The laboratory studies of cement discussed in Section 4 shows that Portland cement is subjected to carbonation when H_2CO_3 is present. Even though the carbonation itself is not a process that is inherently bad for well cement since it reduces its permeability, a continuing source of H_2CO_3 will increase porosity and permeability of the cement (Section 4). Two of the carbonation rate results presented in Section 4 are plotted in Figure 11. As indicated on the figure, the carbonation depth will be 1 mm or 200 mm after 100 years dependant on the salt concentration of the brine. With only a 22 mm thick cement sheet outside the casing in the well, a CO_2-resistant cement slurry should be selected. The more expensive CO_2-resistant cement is suggested as tail slurry with a cement top in the Exshaw shale above the normal pressured and permeable Wabamun Group. Regular cement should be sufficient over the CO_2-resistant cement. However since two different cement slurries will be used, a CO_2-resistant cement that is compatible with regular Portland cement has to be used to prevent flash setting (Section 4).

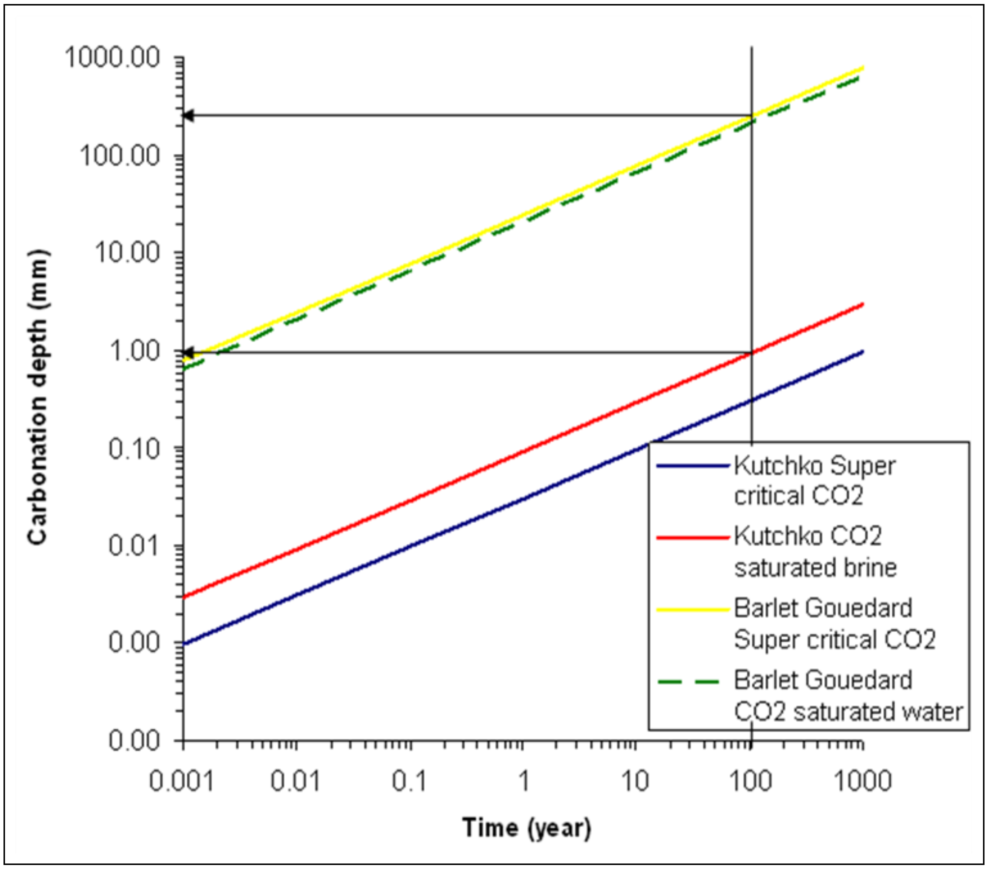


Figure 11: Carbonation depth estimated from laboratory tests after 100 year.

3.4 Completion Design

Corrosion problems have been minimal with dry CO_2 (Meyer 2008; Hadlow, 1992). Since the injected CO_2 will most likely have been transported through carbon steel pipelines, it should not be necessary to change completion materials for the injection wells. The cost estimate is based on a Christmas tree wellhead combination with J55 60.3 mm production tubing. The combined wellhead has casing annulus valves to access all annular spaces to measure the pressure between the casing strings and between the casing and production tubular. Above the Christmas tree is mounted a CO_2 injection valve and an access valve for running wirelines from the top. The production tubing is set on a retrievable packer above the injection horizon to ease the changing of the tubing if pitting is identified during regular inspections, and to seal off the annular space between injection tubular and casing. A safety valve/profile nipple can be used to isolate the wellbore from the formation to allow the tubing string to be replaced. Injection will be conducted through the perforated casing. In the base case there is no stimulation method used, but hydro fracturing may be an option. Using acids to improve injectivity is not recommended because of the possible damage to the cement sheath and casing.

4. INJECTION WELL COST ESTIMATE

This chapter provides a cost estimate for drilling and completing an injection well in the Nisku formation based on the given injection well design. The well assumes a Nisku formation top at 1890 m TVD and a total depth of 1960 m TVD. This well is used as the reference well for estimating well costs for vertical and horizontal wells for various depth ranges. Table 4 outlines the different items of the cost model. In the well cost, it is assumed that the drilling will be conducted during the summer and thereby the PTAC well cost report for summer 2008 was extensively used to identify the costs for the different line items (PTAC 2008). In the basic well design, a 5-day injection test was included but no stimulation fracturing. The time depth curves for three recently drilled wells were used to establish rate of penetration times for the different formations (Figure 12). Average casing running and cementing times were taken from the reference wells. Based on the thickness of the formations at our given location, a drilling time depth curve for our well was constructed (Figure 12). The well will be drilled in 14.9 days (12.7 days without coring the Calmar and Nisku formations).

Table 4: Well cost model WASP project injection well.

Well Cost Model WASP Project Injection Well	
Drilling Cost	
Well fixed costs	Survey, Surface rights, Well design, Site preparation and restoration, Rig move and mobilization
Depth-based well cost	Casing, cementing, mud, logging, and coring
Time-based drilling costs	Loaded rig rate, including rig, fuel, personnel, and equipment rentals
Fixed drilling cost	Total bit costs
Completion Cost	
Completion fixed costs	Wellhead, packer, valves, perforation and wireline runs
Depth-based completion costs	Tubulars and completion fluids
Time-based completion costs	Total rig rate for service rig including, boiler, personnel, engineering services and laboratory analysis
Five-day injection test	Cost associated with five-day injection test

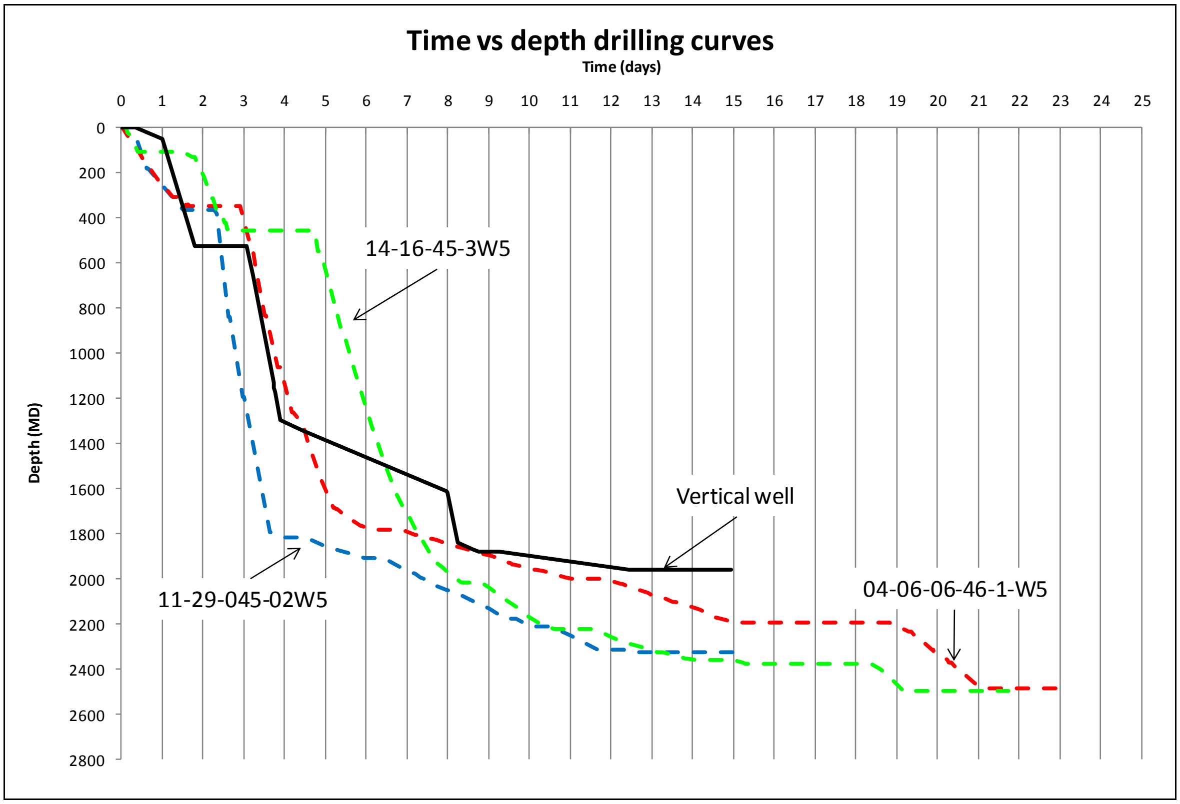


Figure 12: Drilling time for vertical well estimated based on three reference wells in the area.

The estimated cost for drilling the injection well is $1.32 million, with drilling cost $0.93 million and completion cost $0.33 million including 5% contingency costs (Table 5). Table 6 shows the cost for tubulars and cementing. The detailed line-by-line cost including its source is shown in Appendix A.

Table 5: Well cost results WASP project injection well.

Single Vertical Well Cost	Item Cost
Drilling Cost	**$ 932,993**
Well fixed costs	168,920
Depth based well costs	400,708
Time based drilling cost per day	330,365
Fixed drilling cost	33,000
Completion Cost	**$ 325,633**
Completion fixed costs	38,000
Depth based completion costs	83,793
Time based completion costs	138,840
5 day Injection test	65,000
Total Well Cost	**1,258,626**
Total Well Cost Plus 5% Contingency	**$ 1,321,557**

Table 6: Tubular and cementing costs for a vertical well.

Casing, Tubular and Cementing Costs for a Vertical Well					
Type		Conductor	Surface Casing	Production Casing	Production Tubing
Casing depth	m	**50**	**550**	**1,960**	**1890**
Cost	$/m	92	92	72	36
Scratchers, centralizers float and guiding shoe	$/m	2.6	2.6	2.6	
Crew	$/m	6	6	3	
Cement cost and rentals	$/m	62	62	19	
Cement costs	$/m			18	
CO_2 resistant cement	$/m			27	
Total cost casing	**$**	**8,130**	**89,430**	**190,076**	**68,040**

5. ABANDONMENT OF WELLS

When a well is drilled and if it is a dry exploration well, it will be immediately abandoned. Current abandonment practices are to cement all porous zones with a cement plug (Figure 4 left). The cement plug has to be minimum of 30 m (or 60 m for plugs deeper than 1500 m) and extend a minimum of 15 m above and below the porous zone being covered (ERCB Directive 20, 2007). Unacceptable plugs, which are located too low (less than 8 m coverage into non-porous formations) or too high or misplaced (i.e., does not cover the intended porous zone), have to be circulated/ drilled out and a new cement plug set. To protect groundwater, a plug must be set from 15 m below the groundwater base to 15 m above the surface casing shoe. If a casing string is covering the base of groundwater protection zone, remedial cementing and or cement plugs have to cover the zone.

For a well that has production casing, the abandonment procedure is more customized. All non-saline water sources have to be protected and hydraulic isolation must exist between porous zones. This rigorous requirement has been in place since 2003. There are five different options to abandon cased wells using plugs, packers or cement plugs. The three main types are 1) bridge plug set above the perforations with cement over top the plug, 2) squeeze cement in the perforations, and 3) cement plug across perforations. All methods have one common requirement, and that is to have at least 8 m of cement inside the casing that has been pressure tested to 7000 kPa.

At the surface, casing strings are cut 1 to 2 m below the surface and a steel plate is welded to prevent access to the casing strings. This is done after the well is tested for gas migration and surface casing vent flow.

Squeezing cement into openings in casing as remedial cement is often not successful because of the cement's high viscosity. Metal alloy that expand (~ 1%) upon solidification has recently been suggested for remediate cementing and cement plugs (Canitron, 2008). The alloy is placed in the wellbore and a heating tool melts it. The alloy flows to fit the openings of the casing and the volume inside the casing. The expansion helps to avoid micro-fissures that cement can experience because of its shrinkage. Alloy is also claimed to not go through a weak transitional phase during solidification like cement does, and it bonds stronger against clean steel than pure Portland cement. Molten alloy has low surface tension and viscosity and is claimed to fill small fissures and perforations efficiently (Figure 13). Alloys should be CO_2 resistant.

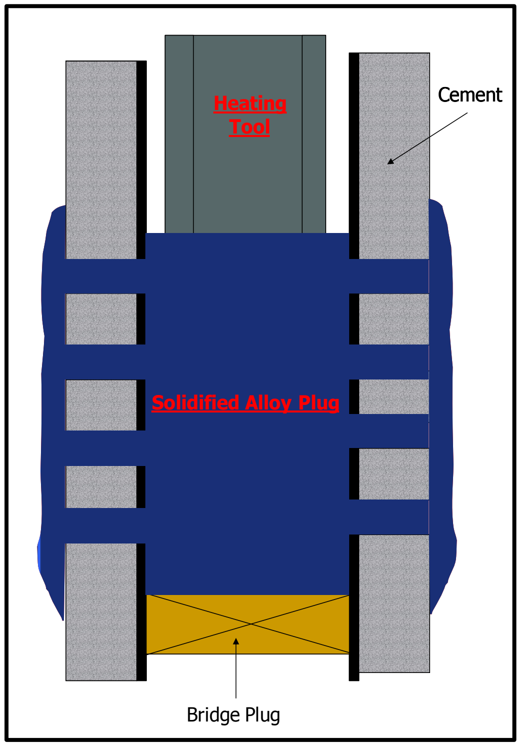


Figure 13: Schematic of using metal alloy plug to seal and abandon production zone (Canitron, 2008).

Removing the casing in certain areas is another method to mitigate leakage caused by poor bond or de-bonding between casing and cement. If wells are plugged and abandoned permanently, both Gray et al, 2007 and Carlsen and Abdollahi, 2007 (Figure 9) suggest the casing steel be removed before installing the final cement plugs. This will remove the most-likely leakage path along the casing. Besides, CO_2 can attack both steel and cement and create leakage paths. In the West Texas field case, it has been seen that reactions have occurred at the casing cement interface and the cement formation interface. Before the final cement squeeze and plug is set, a CO_2-resistant polymer may be injected in the near well bore region to prevent CO_2 from coming in contact with the cement after injection. Cements that are resistant to CO_2 are recommended to seal the reservoir as the cement will be exposed to CO_2 in the future. An open hole completion will reduce the need for milling the casing and may be a simplified solution where appropriate.

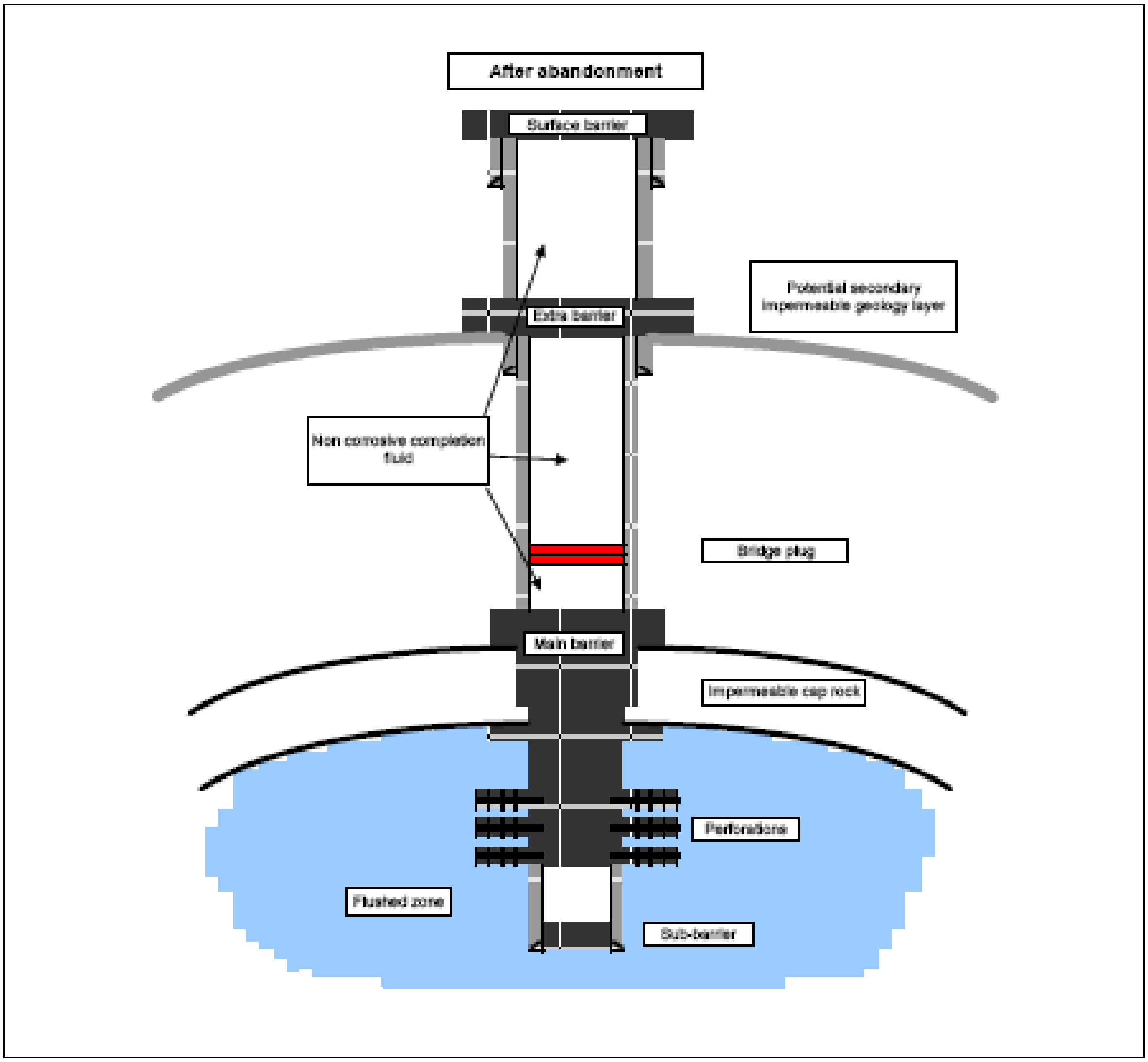


Figure 14: Suggested abandonment method for CO_2 injection wells.

6. EVALUATION OF EXISTING WELLS IN NISKU

A second objective for this study was to evaluate the leakage risk of existing wells within the Wabamun CO_2 storage project area. To identify the number of wells to include in the study, it was assumed that the Calmar seal will hold and only the wells penetrating the Calmar and Nisku formations are at risk. In the area there are 95 wells that penetrate the Nisku formation. Figure 15 presents the age distribution of when these wells were drilled. The wells is classified as either D&A—drilled and abandoned (grey colour) or DC—drilled and cased (white colour). The earliest well was drilled in 1948 and the newest in 2005.

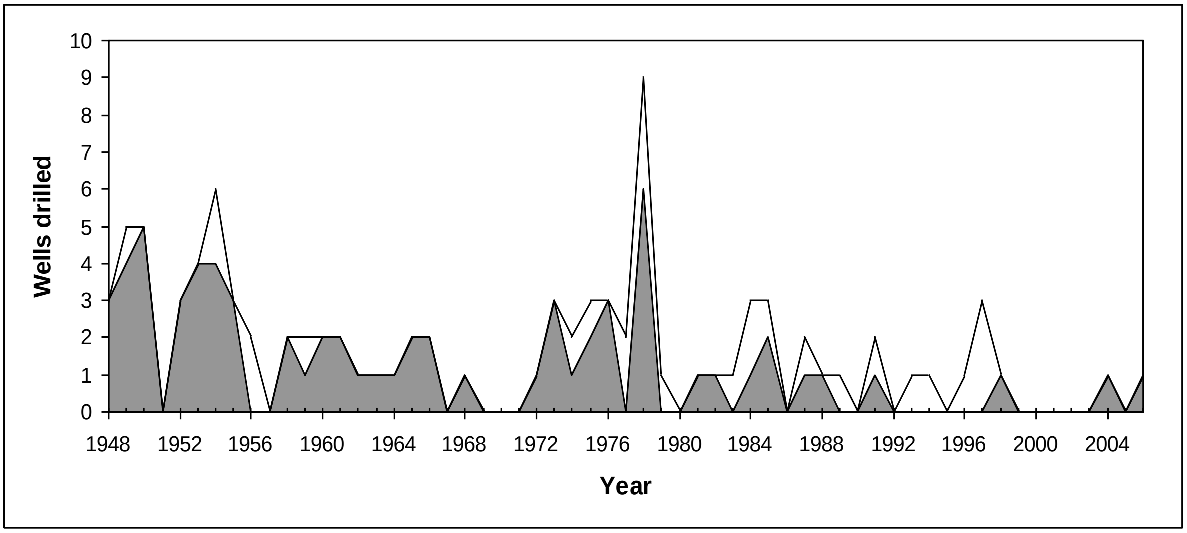


Figure 15: Age distribution of wells drilled through Nisku in the study area. Gray wells are drilled and abandoned, white wells are drilled and cased wells.

The approach taken was to determine if the wells were in an unacceptable condition and a re-abandonment or workover was required. A flow chart was developed to determine which wells were within the pressurized plume area and were candidates for workovers (Figure 16). The first decision in the flow chart is if the wells are drilled after 2003. For these wells, the stricter requirements for zonal isolation were in place and the wells should have little likelihood of leakage. Active wells with cement through Calmar are considered safe, since these wells have their production regularly monitored. Any CO_2 breakthrough would be identified at the wellhead for these wells.

Non-active wells are either suspended or abandoned. Suspended wells in the pressure plume area should be abandoned, or if they currently have a cement sheath through the Calmar seal, should be monitored. The rationale is that older suspended wells may not have the necessary protection around ground water resources. Since cement was not required, carbon steel in casing is not long-term CO_2 resistant and may create a leakage path. Wells abandoned after 1995 are tested for surface casing vent flow and gas migration and is expected to have sufficient integrity.

For earlier abandoned wells, they are either cased and abandoned or plugged or abandoned. Cement in open hole cement plugs in abandoned wells are pure cement or contain a low amount of additives (2% CaCl, 2% bentonite). If open hole plugs exist through caprock wells, the wells should have sufficient seal with a carbonation rate of less than 1mm/10 year. Wells with production casing tend to have higher additive content (2% CaCl, up to 50% bentonite) and thickness of 26 to 57 mm. Higher carbonation rates (e.g., 1mm/year) will expose casing to CO_2 corrosion in a matter of years when wet CO_2 is present. Produced sections with perforations and stimulation through hydraulic fracturing and/or acidizing creates fractures that may have caused increased permeability of the cement sheath. Further bridge plugs with capped cement has shown to be prone to leakage inside the casing. Produced zones can be expected to have low cement integrity for CO_2 brine exposure. If CO_2 enters inside the casing, it can reach the surface. Therefore cased and abandoned wells need further action if cement types and length both inside and outside the casing cannot be verified.

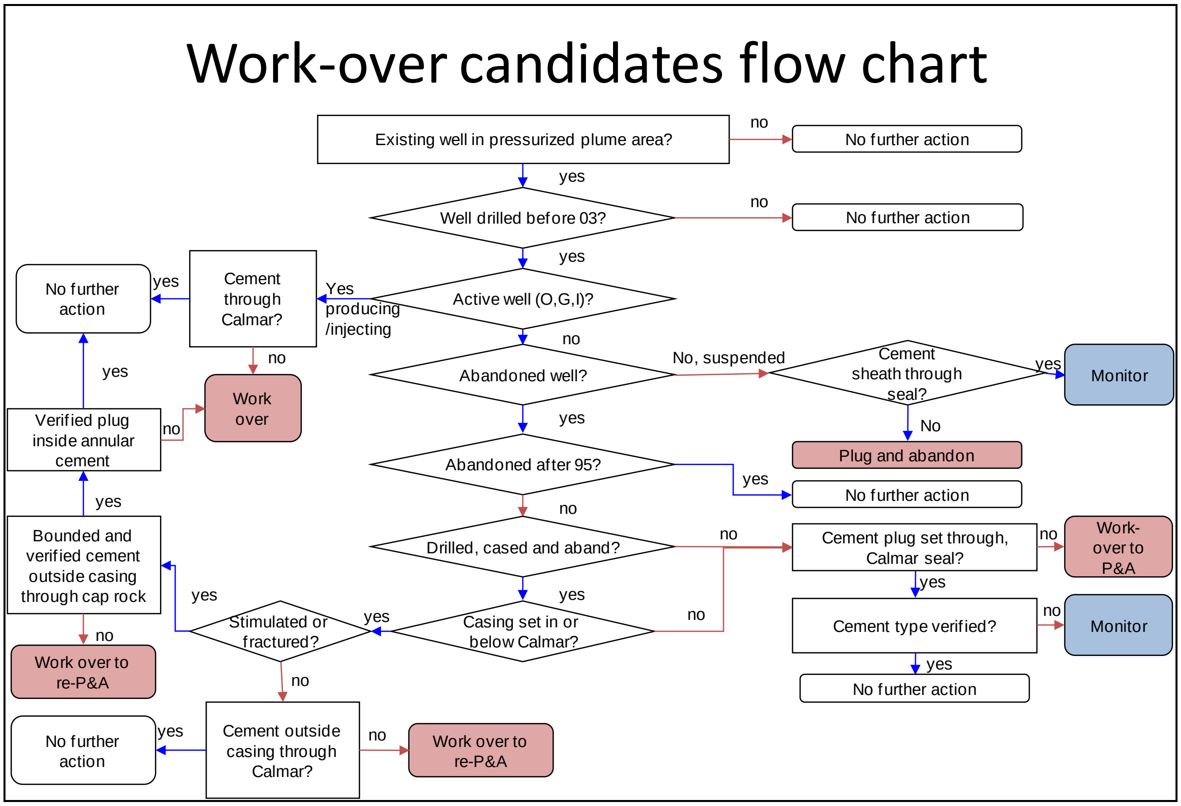


Figure 16: Flow chart for identifying wells which are candidates for re-entering and conduct workover operations to improve leakage integrity.

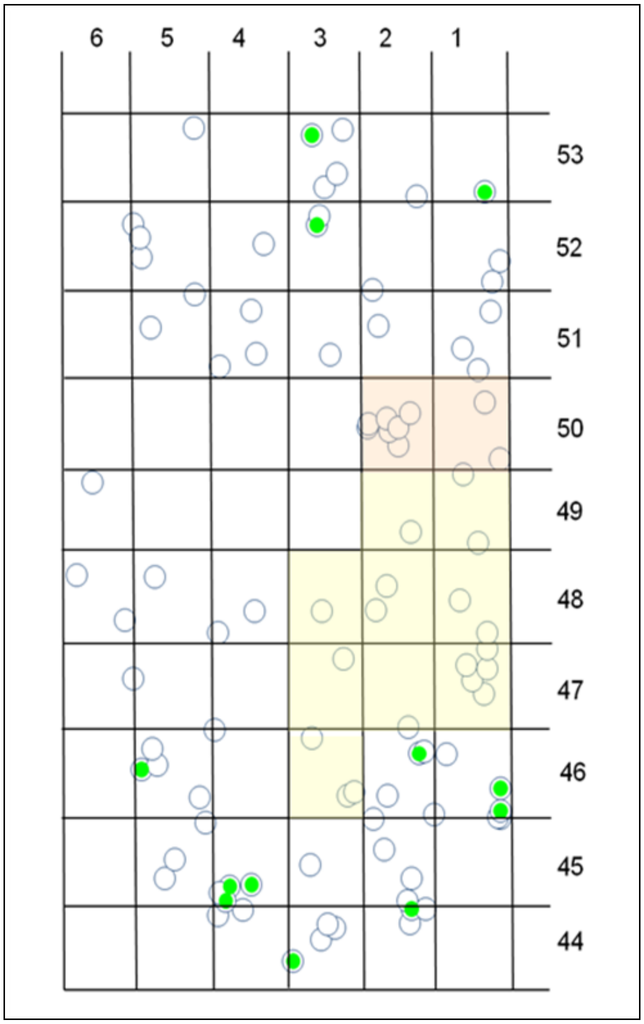


Figure 17: Outline of the study area where horizontal lines are Ranges West of 5 and Vertical squares are Townships. The highlighted area is the focus area where all 27 wells where studied in detailed. Twelve additional wells where randomly selected (indicated in green).

The flow chart was applied to 27 wells inside an 11 township area (the high-graded focus area) (Figure 17). Based on the analysis of 2 out of 17 drilled and abandoned wells, they did not have a verified cement plug through the Calmar and need to be re-abandoned with a new cement plug set (Table 7). For the cased and abandoned wells, 2 out of 8 did not have verified cement inside and outside the casing and therefore require re-abandonment (Table 8). For most of the drilled and cased wells, the production casing was set above the Calmar formation and therefore the well had a verified pure cement plug through the Calmar seal. A small random sample of 12 wells was analyzed for the area to get within a 25% uncertainty range. For those 12 wells, none required workovers. Figure 18 gives the current situation for all wells in the whole WASP study area.

Table 7: Drilled and abandoned wells in focus area.

Well ID	Year Abandoned	Workover Needed?	Plug Length in Nisku (m)	Plug Length Above Nisku (m)
100/11-12-046-03W5/00	1953	no	16.76	51.80
100/16-12-046-03W5/00	1948	yes	0.00	0.00
100/11-33-046-03W5/00	1953	no	66.16	11.60
100/10-22-047-01W5/00	1964	no	16.44	15.00
100/08-26-047-01W5/00	1973	no	13.76	39.00
100/16-35-047-01W5/00	1973	no	14.94	41.40
100/04-36-047-03W5/00	1949	yes	0.00	0.00
100/16-02-048-01W5/00	1952	no	13.12	24.10
100/08-17-048-02W5/00	1984	no	58.90	191.10
100/04-11-049-01W5/00	1950	no	20.46	27.70
100/16-33-049-01W5/00	1954	no	20.14	13.40
100/15-11-049-02W5/00	1950	no	51.08	6.10
100/16-01-050-01W5/00	1952	no	13.50	26.80
100/15-26-050-01W5/00	1949	no	76.20	15.20
100/15-10-050-02W5/00	1948	no	0.00	45.70
100/16-16-050-02W5/00	1960	no	32.30	68.30
100/02-26-050-02W5/00	1954	no	73.80	32.90

For the existing wells that require workovers, the shallow cement plugs will have to be drilled out so that the existing wellbores can be re-entered. New cement plugs will be set through the Nisku and Calmar formations. This workover operation should be conducted safely since the expected downhole pressures are known from the original drilling operation. However, if the wells are within the pressurized plume created by CO_2 injection, wellheads and old casing strings may not have the integrity to handle the elevated pressure. The existing wells will not be CO_2 compliant and the complexity and cost required to abandon these wells will be higher because of the higher pressures and the presence of CO_2. Therefore it is recommended that these wells be re-abandoned before CO_2 injection commences.

Table 8: Drilled, cased and abandoned wells.

Well ID	Year Abandoned	Workover Needed?	Cased in Nisku	Plug Length in Nisku (m)	Plug Length Above Nisku (m)
100/09-10-047-01W5/00	1987	yes	yes	Outside cement to Inside Manville (1592 TVD)	Plug @ 950 m md)
100/12-27-047-01W5/00	1965	No	no	15.3	45.7
100/06-02-047-02W5/00	1961	No	no	0.0	12.8
100/02-21-048-01W5/00	1962	No	no	16.8	16.7
100/02-28-048-02W5/00	1955	No	no	8.3	24.7
100/04-20-050-02W5/00	1958	no	no	84.4	16.8
100/05-20-050-02W5/00	1965	no	no	44.8	11.6
100/02-22-050-02W5/00	1955	yes	no	0.0	0.0

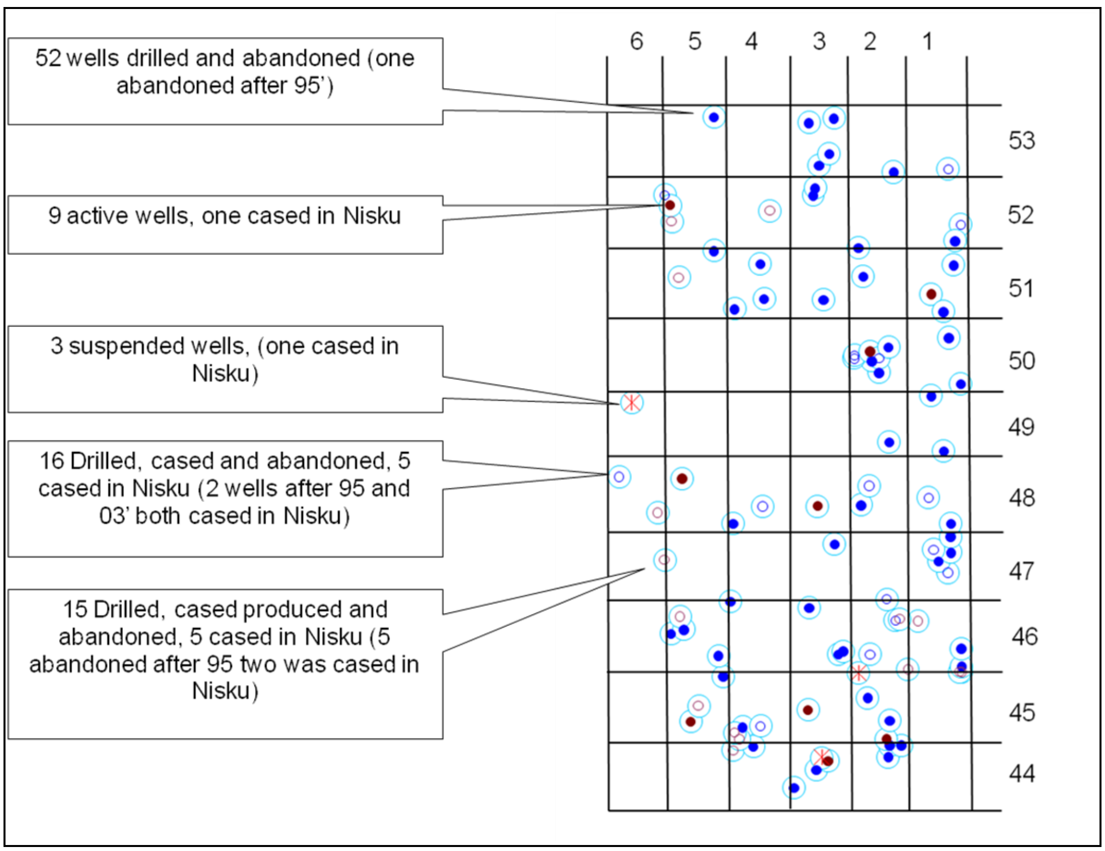


Figure 18: Spatial distribution of all wells penetrating Nisku in the study area.

7. CONCLUSIONS

The well design does not require fundamental changes for a CO_2 injector when compared to regular well designs, since dry CO_2 is expected to be injected into the study areas formation. The cost of one vertical injection well is estimated to be around $1.3 million CAD.

When analyzing the exiting well population, only 4 out of 27 wells are workover candidates. This result makes well leakage from existing wells less of a problem than first anticipated. For the existing wells, only a few have production casing through the Nisku, which is more prone to leakage. The other wells have cement plugs through the caprock with a cement type that will prevent leakage from the Calmar. For existing wells that requires workovers, they need to be performed before pressurizing the reservoir area. The cost and complexity to abandon these wells will increase when the pressures are higher and when CO_2 is present.

The literature survey identified that current well design and abandonment methods should be sufficient to prevent leakage from injection wells. However, there are still some unanswered question relating to the effect thermal and pressure cycles will have on cement sheath integrity in CO_2 injection wells.

8. REFERENCES

Bachu, S and Bennion, B, 2008. Experimental assessment of brine and/or CO_2 leakage through well cements at reservoir conditions, International Journal of Greenhouse Gas Control. Volume 3, Issue 4, July 2009, p. 494–501.

Barlet-Gouédard V, Rimmelé G, Goffe, B and Porcherie, O., 2006. Mitigation strategies for the risk of CO_2 migration through wellbores. SPE paper 98924. Proceedings of the 2006 IADC/SPE Drilling Conference, Miami Florida, 21–23 February 2006.

Barlet-Gouédard V, Ayache B, Rimmelé G, 2008. Cementitious Material Behaviour under CO_2 environment. A laboratory comparison. 4th Meeting of the Well Bore Integrity Network, Paris, France, 18–19 March 2008.

Carey J., Wigand M., Chipera S., Wolde G., Pawar R, Lichtner P., Wehner S, Raines M., and Guthrie G., 2007. Analysis and performance of oil well cement with 30 years of CO_2 exposure from the SACROC Unit, West Texas, USA, International Journal of Greenhouse Gas Control, p. 75–85.

Carlsen M. and Abdollahi, J., 2007. Permanent, abandonment of CO_2 storage wells, Sintef report 54523200.

Celia, M. A., S. Bachu, J. M. Nordbotten, S. Gasda, H. K. Dahle, 2004. Quantitative estimation of CO_2 leakage from geological storage: Analytical models, numerical models, and data needs, In, E.S.Rubin, D.W.Keith and C.F.Gilboy (Eds.), Proceedings of 7th International Conference on Greenhouse Gas Control Technologies. Volume 1: Peer-Reviewed Papers and Plenary Presentations, IEA Greenhouse Gas Programme, Cheltenham, UK.

Canitron, 2008. Alloy Squeeze technology, A New Method for Casing Repair and Vent Gas Flow Shut Off, Industry presentation given 17 March 2008, Calgary, AB.

Crow, W. 2006. Studies on wellbore integrity. Proceedings of the 2nd Wellbore Integrity network Meeting, Princeton, New Jersey, 28–29 March 2006.

ERCB, Directive 51, 1994, Injection and Disposal Wells-Well Classifications, Completions, Logging and Testing Requirements, March 1994.

ERCB Directive 20, 2007, Well abandonment guide, December 2007.

ERCB, 2009. www.ercb.ca.

Gray, K., Podnos, E. and Becker E., 2007. Finite Element Studies of Near-Wellbore Region During Cementing Operations: Part I. Production and Operations Symposium, 31 March–April 2007, Oklahoma City, Oklahoma, U.S.A. SPE-106998.

Hadlow, R.E., 1992. Update of Industry Experience with CO_2 Injection, 67th SPE Annual Technical Conference and Exhibition, 4–7 October 1992, Washington, D.C., SPE-24928.

Halliburton, 2009. www.halliburton.com.

Krilov Z, Loncaric B and Miksa Z, 2000. Investigation of a Long-Term Cement Deterioration under a High-Temperature, Sour Gas Downhole Environment, SPE 58771.

Kutchko BG, Strazisar BR, Dzombak DA Lowry GV, and Thaulow N, 2007. Degradation of wellbore cement by CO_2 under geologic sequestration conditions, Environ Sci. Technol. 41, p. 4787–4792.

Kutchko BG., Strazisar BR, Lowry GV, Dzombak DA, and Thaulow N, 2008. Rate of CO_2 Attack on Hydrated Class H Well Cement under Geologic Sequestration Conditions, Environ. Sci. Technol., 42, p. 6237–6242.

Meyer, 2008. API special reports, Summary of Carbon Dioxide Enhanced Oil Recovery (CO_2 EOR) Injection Well Technology, 62 p.

Milestone, N. and Aldridge L., 1990. Corrosion of Cement Grouts in Aggressive Geothermal Fluids, Geothermal Resources Council Transactions, 14, p. 423–429.

Milestone N., Sugama T, Kukacka LE, and Carciello N, 1986. Carbonation of Geothermal Grouts – Part 1: CO_2 Attack at 150°C, Cement and Concrete Research, 16, p 941–950.

Moritis, G., 2008, SWP advances CO_2 sequestration, ECBM, EOR demos: Oil & Gas Journal, v. 106.37, p. 60–63.

Mulders F., 2006. Studies on Wellbore Integrity, Proc. 2nd Wellbore Integrity Network Meeting, Princeton, New Jersey, 28–29 March 2006.

NETL, 2009, Project solicitation innovative and advanced technologies and protocols for monitoring/verification/accounting (MVA), simulation, and risk assessment of carbon dioxide (CO_2) sequestration in geologic formations, U.S. Department of Energy (DOE) DE-FOA0000023-01.

Onan D. D, 1984. Effect of Supercritical CO_2 on well cement, SPE paper 12593, p. 161–172

Orlic B and Benedictus T, 2008. Some geomechanical aspects of well integrity, 4th Meeting of the Well Bore Integrity Network, Paris, France, 18–19 March.

Pedersen RO, Scheie A, Johnson C, Hoyos JC, Therond E and Khatri DK, 2006. Cementing of an offshore disposal well using a novel sealant that withstands pressure and temperature cycles, SPE 98891. IADC/SPE Drilling Conference, Miami, Florida, USA, 21–23 February 2006.

PTAC, 2008.

Randhol, P. and Carlsen, I.M. 2008. Assessment of Sustained Well Integrity on the Norwegian Continental shelf. Fourth meeting of the IEA-GHG Wellbore Integrity Network, 18–19 March 2008, Paris, France.

Randhol, P. Cerasi, P. 2009. CO_2 Injection Well Integrity. Sintef report. 31.6953.00/01/08.

NPA, 2008. Norwegian Petroleum Safety Authority, 2008. Well integrity survey phase 1. www.ptil.no.

Schlumberger, 2009. www.slb.com

Shen, J and Pye. D., 1989, Effects of CO_2 attacks on Cement in High Temperature Applications, SPE/IADC 18618, presented at SPE/IADC drilling conference, New Orleans, LA, 28 February–3 March 1989.

Watson, T.L. and Bachu, S. 2007. Evaluation of the Potential for Gas and CO_2 Leakage along Wellbores. SPE 106817. E&P Environmental and Safety Conference, 5–7 March 2007, Galveston, Texas, U.S.A.

APPENDIX A

Appendix A: Vertical well cost model WASP project injection well						
Line cost Item description	**Cost**		**# Units based on well design**	**Cost per Unit**	**Units**	**Source**
Well fixed costs	**168,920**					
Survey, Surface rights, Well design	16,500	$				
Surface lease	2,500	$	1	2500	$ /hectar	PTAC 2008 well study average hectar cost
Surveying	3,500	$	1	3500	$/day	PTAC 2008 well study
License and application fee	500	$	1	500	$/licen se	PTAC 2008 well study
Detailed engineering	10,000	$	80	125	$/hour	PTAC 2008 well study for hourly rate
Site preparation and restoration	104,000	$				
Road	20,000	$	2	10,000	$/km	PTAC 2008 well study, typical road length evaluated based on existing road density in Wabamun area
Site preparation	40,000		4	10,000	$/day	PTAC 2008 well study
Restoration	40,000		4	10,000	$/day	PTAC 2008 well study
Special construction	0					
Company man supervision	4,000		4	1000	$/day	PTAC 2008 Well study
Rig move and mobilization	48,420	$				
Rig move	38,400		20	1920	$/load	Cost per load assuming 8 hour per 100km, 80 km from Edmonton to Wellsite
Rig permit	500	$	1	500		PTAC 2008 Well study
Rig mobilization	9,520	$	1	9,520	$/day	PTAC 2008 Well study
Appendix A page 2						
Depth based well cost	**400,609**	$				
Conductor	8,130					Details in report
Surface casing and cementig	89,430	$				Details in report
Intermediate surface casing and cemen	0	$				
Production casing and cementing	190,076	$				Details in report
Production liner	0	$				
Mud	30,589					
Surface mud and chemicals	4,187	$	84	$50	$	PTAC 2008 Well study
Main mud and chemicals	18,112	$	121	$150	m3	PTAC 2008 Well study
Mud removal	6,037	$	121	$50		PTAC 2008 Well study
Waste management	2,253	$		$2,253		PTAC 2008 Well study
Logging	25,480	$				
	25,480	$	1,960	$13.00	$/m	PTAC 2008 Well study
Coring	56,903	$				
Time Based drilling costs	**330,365**	$	12.70		Days	From ROP evaluation
Time based drilling cost per day	26,013					
Loaded rig rate	21,338	$/day				
Rig rate	11,900	$/day		11675		PTAC 2008 Well study
Rig insurance	100	$/day	1	100		PTAC 2008 Well study
Fuel	1,500	$/day		1500		PTAC 2008 Well study
Personell						
Drilling supervisor	1,250	$/day	1	1250		PTAC 2008 Well study
Well site geologist	-	$/day	0	1000		PTAC 2008 Well study
Driller	1,008	$/day	2	$42		CAODC May 2009
Assistant Driller	888	$/day	2	$37		CAODC May 2009
Derrickhand	864	$/day	2	$36		CAODC May 2009
Motorhand	756	$/day	2	$32		CAODC May 2009
Floorhand	720	$/day	2	$30		CAODC May 2009
Leasehand	672	$/day	2	$28		CAODC May 2009
Accomodation cost	1,680	$/day	12	$140		CAODC May 2009
Crew transportation	180	$/day	12	$15		Assumed
Mud logging	775	$/day	1	$775		Fully loaded cost (PTAC 2008)
Wac truck	1,600	$/day	1	$1,600		PTAC 2008 Well study

Appendix A Page 3					
Rentals	4,675	$/day			
Well site trailer	450	$/day	2	225	PTAC 2008 Well study
Solid equipment	175	$/day	1	175	PTAC 2008 Well study
Sump pumps	800	$/day	1	800	PTAC 2008 Well study
Tank rental	1,000	$/day	1	1000	PTAC 2008 Well study
Down hole tool rental	1,300	$/day	50	26	PTAC 2008 Well study
water and trucking	950	$/day	1	950	PTAC 2008 Well study
Fixed drilling cost	**$ 33,000**				
Total bit costs	$ 33,000				
Conductor	-	$			
Surface hole	5,000	$	1	5000	PTAC 2008 Well study
Intermediate hole	-	$			
Production hole	28,000	$	2	14000	PTAC 2008 Well study
Production liner					
Total drilling costs	**932,893.61**				
Completion fixed costs	38,000	$			
Well head	14,000	$	1	14000 $	PTAC 2008 Well study
Packer	12,000	$	1	12000 $	PTAC 2008 Well study
Safety valve	12,000	$	1	12000 $	PTAC 2008 Well study
Perforating	8,000	$	1	8000 $	PTAC 2008 Well study
Wireline	10,000	$	5	2000 $	PTAC 2008 Well study
Depth based completion costs	83,793	$			
Tubular	68,040	$			PTAC 2008 Well study
Completion fluids	15,753	$	14.3	1100 $/m3	PTAC 2008 Well study
Time based completion costs	138,840	$	8		PTAC 2008 Well study
Rig rate fully loaded	17,355				
Service rig	7,500				PTAC 2008 Well study
Boiler	1,950				PTAC 2008 Well study
CSA	800				PTAC 2008 Well study
Crew transport	780				PTAC 2008 Well study
Hauling and trucking	1,500				PTAC 2008 Well study
Vacuum truck	1,450				PTAC 2008 Well study
Vater and trucking	1,000				PTAC 2008 Well study
Completion supervision	1,500				PTAC 2008 Well study
Fluid analysis	500				PTAC 2008 Well study
Engineering services	375				PTAC 2008 Well study
Appendix A Page 4					
5 day Injection test	65,000	$	5	5500	Estimate for additional injection testing equipment, crew and analysis
Total Completion costs	**325,632.76**				
Total well cost, 5% contingency	**1,321,453**				