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How Cement Operations affect your Cement Sheath Short and Long Term Integrity

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Abstract

The cement sheath is one of the primary barriers to prevent wellbore leakage and failure. The integrity of the cement sheath begins at the cementing operation and what happens there can greatly affect the long term integrity of the well. This study investigates how the operating conditions at the time of cementing affect the short term and long term cement sheath integrity. The operating conditions considered were circulation temperature, internal casing pressure, and cement hydrostatic pressure. Simulations of the cementing operation were conducted to calculate pressure changes behind the casing and to predict short term integrity. The resulting pressures were used in staged finite element simulations to predict the long term integrity of the well after being loaded by various operations. The results show that in certain situations the cementing operation's temperature changes can result in fluid loss, formation fractures, or formation fluid influxes in the short term. In the long term the initial setting conditions can greatly dampen future loading and stress changes which result in a much more resilient wellbore with the only change being based on a simple fluid pressure. In conclusion, the pressure and temperature conditions during the cementing operation can greatly affect the integrity of the wellbore. These simple adjustments can create a resilient wellbore which can serve as an effective barrier throughout the entire life of the well.

Introduction

The primary goals of the cement sheath are to isolate the wellbore from the formation fluids and to support the casing. The cement is designed to prevent fluid flow into adjacent formations and to the surface by creating an impermeable barrier in which formation fluid cannot flow past. In addition, the cement sheath also prevents the wellbore fluids from entering the formation during the drilling operation[1].

The various leakage paths that can occur in the near wellbore region are presented in Figure 1. The leakage paths are divided into two categories, primary and secondary. Primary leakage paths occur due to events and conditions during the primary cementing, while the secondary leakage paths are those that occur after the primary cementing is complete. All of these leakage paths compromise the wellbore integrity and can allow fluid to flow into the annulus or the wellbore. In this study leakage paths #1 (incomplete annular cement job does not reach sealing layer), #5 (channeling in the cement), #7 (de-bonding due to tensile stress on casing-cement-formation boundaries), and #8 (fractures in the cement of formation) will be discussed.

PRIMARY
1. Incomplete annular cementing job, does not reach seal layer
2. Lack of cement plug or permanent packer
3. Failure of the casing by burst or collapse
4. Poor bonding caused by mudcake
5. Channeling in the cement
6. Primary permeability in cement sheath or cement plug

SECONDARY
7. De-bonding due to tensile stress on casing-cement-formation boundaries
8. Fractures in cement and formation
9. Chemical dissolution and carbonation of cement
10. Wear or corrosion of the casing

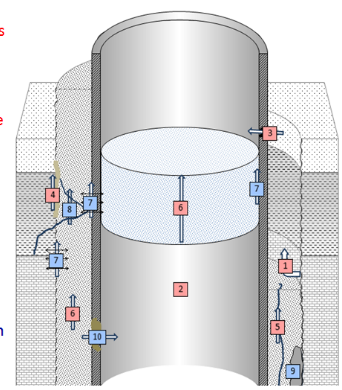


Figure 1: Leakage paths in near wellbore region

Deep water and high pressure high temperature (HPHT) wells have raised concerns about trapped annular pressure becoming a design issue in well completions[2,3]. The issue with trapped annular pressure with thermal loading was discussed by Mitchell and Sweatman[4] who found that in HPHT wells the change in fluid temperature resulted in significant pressure changes along the well. Mitchell and Sweatman[4] found that in an open annulus, where fluid is able to leave the annulus, if the temperature increases the synthetic mud density decreases resulting in a lower pressure and that if the temperature decreases the mud density increases resulting in a higher wellbore pressure. Additionally, Mitchell and Sweatman[4] found that in a closed annulus, where the annulus is closed off and no fluid can leave, that the changing fluid volume with temperature changes results in a pressure development based on the fluid compressibility.

The state of stress within the cement once it sets is the key to determining cement sheath integrity. Nelson and Guillot[1], Thiercelin et al.[5], Bosma et al.[6], Ravi et al.[7], and Simon and Boukhelifa[8] assumed that the initial effective state of stress before shrinkage or expansion in the cement was equal to 0 MPa. Nelson and Guillot[1] used the observations from Cooke et al.[9] and Morgan[10] to determine that the total stress in the cement unloads as the gel strength develops and drops to at least formation pore pressure. Therefore it would be predicted that there is zero effective stress in the cement if the total stress equals the pore pressure. The pressures calculated by Bosma et al.[6] and Ravi et al.[7] also confirm the ideas of Nelson and Guillot[1]. Under these zero effective stress conditions the risk for a shrinking cement to fail under tension is high since the shrinkage stresses could put the cement sheath under tension. However, as pointed out in Gray et al.[11] and Bois et al.[12], assuming zero effective stress with no shrinkage is an insufficient assumption. Gray et al.[11] and Bois et al.[12] both stated that the total stresses within the cement sheath would be equal to the pressure in the cement column. Gray et al.[11] notes that the casing and formation are subjected to cement slurry hydrostatic pressure and according to Newton's Third Law, if a body exerts a force on a second body then the second body exerts the same force back. Bois et al.[12] stated that as the casing expands and contracts during cement setting, the cement is in a plastic fluid state which means it is unable to restrain these movements. Therefore, a negligible stress is developed in the cement sheath. An in-situ stress condition where the cement stress is equal to the slurry hydrostatic pressure and effective stress is taken into account is the most reasonable boundary condition assumption, because a zero effective in-situ state of stress would result in persistent failure and a total stress assumption would result in an overly resilient wellbore[13]. Therefore, the authors suggests that an effective stress in-situ stress condition is the case which best represents the actual setting process.

The objective of this paper is to investigate the effect the decision of having an open or closed annulus has on the cement sheath integrity. The effects of casing and formation expansion with temperature and pressure are considered for both the change of temperature during cement setting and throughout the lifetime of the well. Two very different cases will be investigated. The first case will be a conventional onshore well under the conditions of open and closed annulus using actual well conditions. The analysis will be repeated for a typical HPHT well in the North Sea.

Methodology

The analysis is conducted in two parts. First the changes in pressure of the annular column will be calculated by the various changes in the annular volume and fluid properties. Adams[2] investigated these effects using finite element and analytical modeling by proposing a general formula. Secondly, the long term integrity conducted using the pressure results from the first part as boundary conditions. Figure 2 is a wellbore cross section showing the casing, cement, and formation. The radii and pressures are labeled as they appear in the equations. The volume changes of interest are those of the annular space and the fluid in the annulus. The annular space changes are a function of the casing and formation displacements and the fluid volume changes caused by the thermal expansion of the fluid. Additionally, there are piston compression effects in the closed annulus that must be taken into account to accurately model the section. Once the pressures in the annulus have been determined the long term integrity will be assessed using staged finite-element analysis which will simulate the initial conditions of the well, the drilling conditions, cementing conditions, production conditions, depletion conditions, and the injection conditions. These scenarios will be used to determine the long term integrity of the cased wellbore.

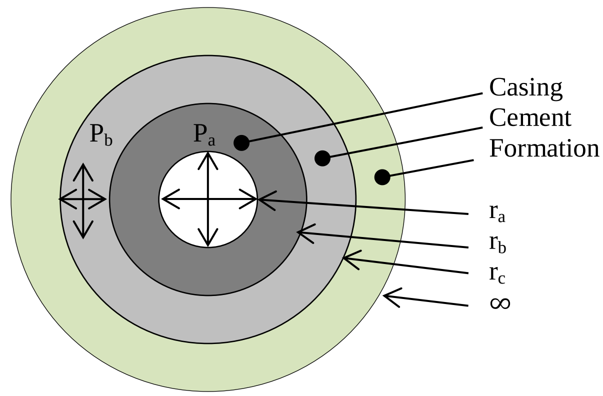


Figure 2: Wellbore diagram for equations

Casing Displacement

The casing displacement is governed by the temperature changes as well as the internal and external pressure changes. The material properties of the casing used are those of typical steel which are provided in Table 1. Equation 1 is the solution for radial displacement of a thick walled cylinder with temperature and pressure compensation given in Timoshenko and Goodier[14].

$$u = \frac{1+v}{1-v}\frac{1}{r}\frac{1}{2}\alpha T(r^2 - ra^2) + C1r + \frac{C2}{r}$$

$$C1 = \frac{(1-2v)(1+v)\left[\left(2(1-v)\left(P_b r_b^2 - P_a r_a^2\right) + ET\alpha(r_b^2 - r_a^2)\right]}{2E(r_b^2 - r_a^2)(1-v)}$$

$$C2 = \frac{(1+v)r_a^2\left[\left(2(1-v)r_b^2(P_b - P_a) + ET\alpha(r_b^2 - r_a^2)\right]}{2E(r_b^2 - r_a^2)(1-v)} \qquad (1)$$

The equations describe u as radial displacement, v as Poisson's ratio, alpha as thermal expansion, T as temperature and P_b and P_a are pressure at outside of the casing and at the outside of the cement sheath, respectively. The displacement of the casing will begin with the expansion due to the temperature change. All pressures experienced at the start of the cement job, such as the internal pressure of the casing and the pressure in the annulus are not taken into account because they are in place during the start of the cement job and the cement goes in under these conditions. The changes in pressure due to annular column height changes, density changes, and compression will be taken into account. These changes occur after the initial pumping of the cement job. The change in volume of the annular space will be based on the outer diameter of the casing and the hole diameter. The inner diameter of the casing changes should be calculated to reflect the changes in casing dimensions.

Table 1: Casing Properties

Young's Modulus, E	29,000ksi
Poisson's Ratio, v	0.3
Linear Thermal Expansion, α	7.3με/°F

Formation Displacement

The formation is modeled as a linear elastic material and the properties are given in Table 2. The formation and therefore wellbore hole diameter will expand and contract with temperature and pressure changes. Equation 2 gives the solution for displacement of an infinite radius hollow cylinder as described by Jo[15].

$$u = C1r + \frac{C2}{r}, \quad C1 = 0, \quad C2 = \frac{P_b r_c^2 (1 - v)}{E} \qquad (2)$$

Due to the formation's low thermal conductivity it will be much more resistant to the temperature changes caused by circulation. Therefore Equation 2 is simplified not to include temperature changes because the formation will be assumed to be at or very close to the formation in-situ temperature.

Table 2: Formation Properties

Young's Modulus, E	3,627ksi
Poisson's Ratio, v	0.27
Linear Thermal Expansion, α	5.6με/°F

Thermal Expansion of Fluid

The thermal expansion of the wellbore fluids is the primary contributor to the increase in pressure of a closed annulus and the reduction of fluid from an open annulus. The volumetric thermal expansions (β) for water and oil based mud are presented in Table 3. The oil-based mud properties are taken form OBM1 from Zamora et al.[16]. The expansion of this fluid in a closed annulus will add to the compressibility pressure increase. In the open annulus the expansion of fluid will result in a lower density of the annular fluids. Equation 3 is used to calculate the change in volume (ΔV) of the annular fluids

$$\Delta V = \beta T V \qquad (3)$$

Table 3: Thermal Volumetric Expansion, β

Water	0.0002140/°F
Oil-Based Mud*	0.0002546/°F

*Calculated from OBM1 from Zamora et al.[16]

Isothermal Compressibility

The compressibility of the fluid is only taken into account in the closed annulus. When the casing and fluid expand with a temperature increases the volume will remain constant. This requires an increase in pressure. The increase in pressure can be calculated using the isothermal compressibility. Since the thermal expansion of the fluid is taken into account in the previous step the problem can be simplified using the isothermal compressibility. Equation 4, gives the change in pressure required.

$$\Delta p = -\frac{\Delta V}{V k_T} \qquad (4)$$

where, k_T is isothermal compressibility. The values of isothermal compressibility are given in Table 4 for water and oil-based muds.

The compressibility is calculated by taking the original volume of the annulus before temperature change and calculating the volume change caused by the casing and the formation because of pressure. Then adding the thermal expansion volume to that volume change gives the initial volume change and initial piston pressure before any relaxation of the casing. Once the change in pressure is calculated the casing and formation displacements must be recalculated with the new pressure using Equations 1 and 2, then a new volume of the annulus is calculated. Then the steps are repeated until there is no additional volume change and the sum of the compressibility pressures are summed to get the final pressure.

The reason for the iteration of calculations is due the fact that when the first volume change is made the pressure will increase. After that pressure increase the casing and formation will expand and pressure will decrease. This pressure decrease will then cause the casing and formation area to decrease, which will then increase pressure. The calculation repeats until there is no volume change between consecutive calculations.

Table 4: Isothermal Compressibility, k_T

Water	3.101μ/°F
Oil-Based Mud*	2.823μ/°F

*Calculated from OBM1 from Zamora et al.[16]

Long Term Modeling

The approach followed in this study is based on replicating the life of the well by including all loading steps occurring throughout the wells life. Figure 3 shows a schematic of the borehole cross section and the loads (mechanical and thermal) that are applied on them. Details of the steps followed in numerical simulations are also illustrated on the right side of Figure 3. The mesh for finite element study was constructed in HyperMesh™ software[17] and the actual finite element simulations were conducted in Abaqus™ software[18]. The three-dimensional mesh has one and five meter length in *z* and (*x*,*y*) directions respectively and is composed of first order elements. The decision on model geometry was based on preventing unintentional boundary effects in the model as a result of the temperature distribution reaching the boundary of the model. The numerical model also assumes homogeneity in all materials including casing, cement and formation. Although heterogeneous considerations can be more realistic it is outside the scope of this study. The main goal from numerical models is to propose a robust multi-stage modeling approach for near wellbore integrity situations and to capture the effect of dynamic loads on the near wellbore area.

The staged finite-element model uses the property of superposition to build the model initial conditions before the next step of loading is implemented. The advantage of building the model in several steps is to observe and record stress and deformation changes after each loading[11].

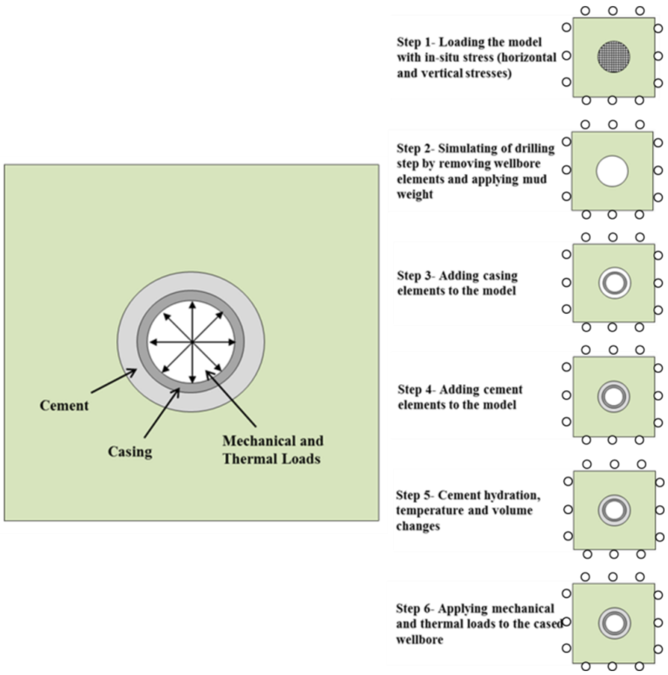


Figure 3: Staged finite element model steps

Details of the staged finite element steps modified from Nygaard et al.[19] to include a cement hydration step are followed in the numerical simulations and are as follows:

Step 1. Loading the model with in-situ stress: In this step two horizontal stresses (minimum and maximum) and overburden stress are applied to the all elements in the model. Additionally, an initial temperature reservoir temperature was applied to all the nodes.

Step 2. Drilling step: In this step wellbore elements are removed from the model, and mud pressure is applied to the wellbore face. Stress equilibration was achieved at the end of the step and near wellbore state of stress was imposed. This step simulates the drilling process of the borehole.

Step 3. Running Casing: Casing elements were introduced to the model at this step with mud pressure applied to the inside and outside of the casing. Linear-elastic behavior was assumed for the casing elements.

Step 4. Cementing: At this stage, cement elements were introduced to the model. The cement elements were fully bonded to the formation. These elements were also activated with zero deformation but under initial hydrostatic slurry pressure. The cement is not yet hardened and its internal stress will be equal hydrostatic pressure. This status is defined as initial conditions for the cement elements before loading step starts. Mohr-Coulomb softening material model is applied for cement elements, which is essential for predicting plastic failure in cement when thermal and mechanical loads are applied to the model.

Step 5. Hydration: After the cement is in place, hydration of the cement begins. The hydration includes a decrease in temperature from the elevated temperature of hydration that develops while the cement is in slurry state and develops no strain. Shrinkage of the cement occurs as a volumetric strain, according to Sabins and Sutton[20] who found that 95% of shrinkage occurs after the initial set. Pore pressure is reduced in this step. For this analysis shrinkage and pore pressure changes neglected.

Step 6. Applying pore pressure, thermal, and mechanical loads: After cement and casing were set, the final stage is to apply thermal and mechanical loads for the cased wellbore. Mechanical loads were applied by using distributed load on casing surface and thermal load was defined by putting thermal boundary conditions on casing nodes. One day's worth of temperature change using a transient model was simulated to allow the boundaries to remain at their initial temperature. The elements used for casing, cement and formation have features for coupled thermal-displacement analysis with the options to define thermal conductivity, thermal expansion and specific heat values.

Cement Properties

The cements that will be used in the analysis are described in Table 5. The mechanical and thermal properties important to this analysis are the slurry density, Young's Modulus, Poisson's Ratio, linear thermal expansion coefficient, and cement tensile strength. The slurry density is used in the calculation of annular column pressure. The Young's Modulus and Poisson's Ratio are used to describe the cement's mechanical response to mechanical and thermal loadings. The thermal expansion coefficient is used to describe the strain response due to thermal loading. The tensile strength is used to identify failure of the cement in tension. The properties found in Table 5 are experimentally derived using laboratory experiments for each composition.

Table 5: Cement mechanical and thermal properties

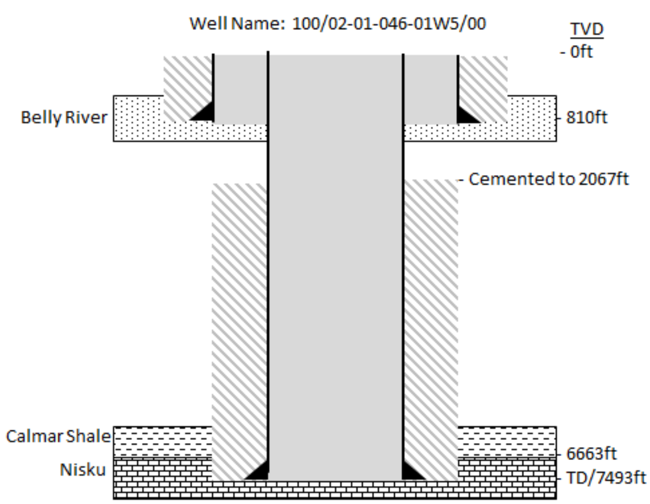
	Neat	Barite
Slurry Density, ρ, ppg	16	17.5
E, ksi	1403	1212
υ	0.214	0.22
α, με/°F	5.4	4.0
Tensile Strength, To, psi	216	271

Onshore Wabamun Area Case Study

This case study looks at the well 100/02-01-046-01W5/00 as it is described in the Tour Report[21] and Well Ticket[22]. This well was drilled in 1987 and abandoned in 2003. The well has been drilled into the Nisku formation and its integrity was evaluated in the Wabamun Area CO_2 Sequestration Project

(WASP)[23]. This well is used as a typical example of an existing well design which could be repurposed from its original design as a production well to a potential injection well. When a well is to be used for another purpose other than its original purpose, careful consideration must be made of the well's current integrity as well as the effectiveness of the older well design to meet new design criteria. The integrity of the design must be evaluated and this evaluation must begin with the beginning of the life of the well, the cementing job. The well was drilled and cemented using water based drilling fluids and neat cement, 16ppg. The well is sketched in Figure 4. The point of interest to test for leakage and integrity is at sealing formation above the production casing shoe. This point is chosen because it is at this point that loss of integrity or leakage would cause leakage from the sealing formation.

The 7" production casing, 26lb/ft, is set at a TVD of 7493ft in the Nisku formation in an 8 3/4". The casing was cemented to TVD of 7493ft using neat cement. The production casing exits the sealing formation, the Calmar Shale, at TVD of 6663ft, making this the point of interest for the onshore well.



Prod Casing ID	Prod Casing OD	Prod Hole D	Surf Casing ID	Surf Casing OD	Surf Hole D
6.28"	7"	8.75"	8.92"	9.625"	13.75"

Figure 4: Onshore well 100/02-01-046-01W5/00 casing and cement design

The temperature profile for circulation temperature and formation temperature are presented in Figure 5. The formation temperature is taken from well data from the Wabamun area and the casing circulation temperature is taken from Dillenbeck et al.[24]. The study gave the test results for a heat of hydration test for the cement and found that the temperature increases about 27°F[24]. Assuming the circulation temperature is 27°F less than the formation simplifies the problem to a single temperature change. Two supposed situations of the annular space are considered to compare the effect annular pressures has on the cement. One is case when the annulus outside the production casing was closed in when cement was set. The second case is when the fluid in the annulus is freely able to leave the annulus.

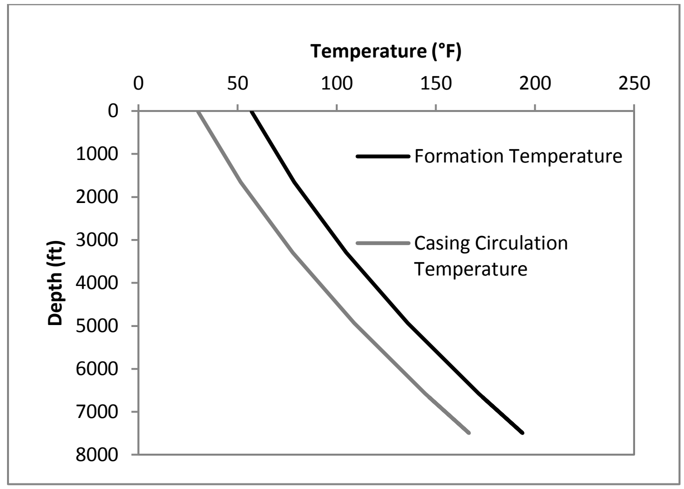


Figure 5: Wabamun formation and circulating temperature profiles

Open and Closed System

In the 100/02-01-046-01W5/00 well in the Wabamun area, the results of the changes from a planned cementing design are given in Figure 6. The density vs depth plot gives the pore pressure and fracture gradients for the well[25]. The gradients are plotted from TD to the surface casing shoe. This plot shows that the use of an open annulus results in a pressure distribution throughout the column which is mostly unchanged from the planned distribution. But in the closed annulus situation the pressure increases due the volume reduction of the annulus and the fluid volume increase resulting in higher compressional pressures. It can be seen by the closed column density line that at the casing shoe there will be leak off into the formation as stated by Adams[2]. The primary difference between these results and the Mitchell and Sweatman[4] results are they assume the wellbore integrity is lost because of the crossing over the fracture gradient of the formation, but the fracture gradient is determined from leak off tests, LOT, which only show the onset of fluid leaking into the formation. It can be seen that once a fluid volume equal to the compression pressure has been leaked off, the pressure in the column will decrease until it no longer crosses the fracture gradient line. In this situation it was found that 0.03bbl of annulus fluid would have to leak off in order to move the column pressure inside the fracture gradient. The fluid loss is almost insignificant which means that there would not be a loss of overall well integrity.

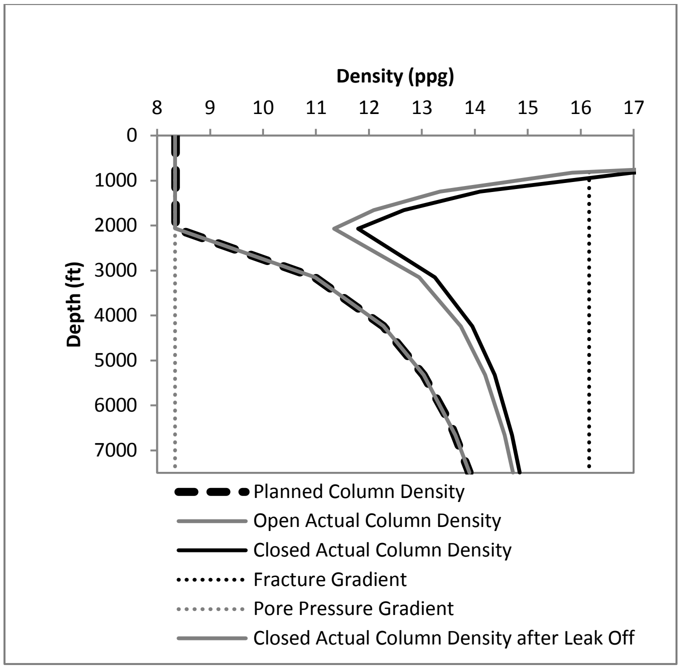


Figure 6: Wabamun onshore density plot of open and closed annulus conditions with fracture gradient and pore pressure gradient

Long Term Results

The simulation loading for the single casing at 6663ft is described in Table 6. Table 6 also gives the production casing and hole diameters used in the model. The production casing cement is given as neat cement for the well. The cement pressure will be determined from the cement type at its associated density. The production cement is cemented from TD to 2067ft, so the cement pressure will be based on 2067ft of fresh water at 8.34ppg and the interval of cement from 2067ft to 6663ft and density of the neat cement, 16ppg. Additionally, the well will be loaded in a separate scenario with a U-tube pressure in which the pressure inside the casing is equal to the outside of the casing at the bottom of the hole. This scenario would simulate a situation where the casing plug was not seated and equalizing pressures of the inner casing and outer casing was used to prevent flow.

The production temperature will be equal to the formation temperature at the bottom of the well in the perforated section at 7493ft with a temperature of 194°F. The production pressure will be equal to the bottom hole pore pressure equal to 3.25ksi. The depletion of the reservoir will be simulated with the same production temperature but a production pressure of half the bottom hole pore pressure.

The injection temperature for CO_2 injection was taken from Ruan et al.[26] who used numerical simulations to approximate the fluid temperatures behind the tubing and at the casing. The injection temperature and formation temperature are given as 82°F and 174°F, respectively. These values are determined from Figure 7 at a depth of 6663ft. The hydrostatic and pore pressure of 2.89ksi is found by using a fresh water density of 8.34ppg and the depth of interest. The injection pressure assumes a 2.9ksi pump pressure at the surface to compress the CO_2 gas to a supercritical state which would result in a CO_2 density near that of fresh water, 8.34ppg.

Table 6: Long term simulation conditions for onshore well

At 6663ft:		
Prod Casing ID	Prod Casing OD	Hole D
6.276”	7”	8 ¾”
In-Situ Vertical Stress	3.34ksi	
In-Situ Max Horizontal Stress	3.19ksi	
In-Situ Min Horizontal Stress	2.90ksi	
Production casing cement	Neat Cement	
Production Temperature	194°F	
Production Pressure	3.25ksi	
Depleted Temperature	194°F	
Depleted Pressure	1.63ksi	
Injection temperature	82°F	
Formation temperature	174°F	
Hydrostatic/Pore Pressure	2.89ksi	
Injection Pressure	5.79ksi	

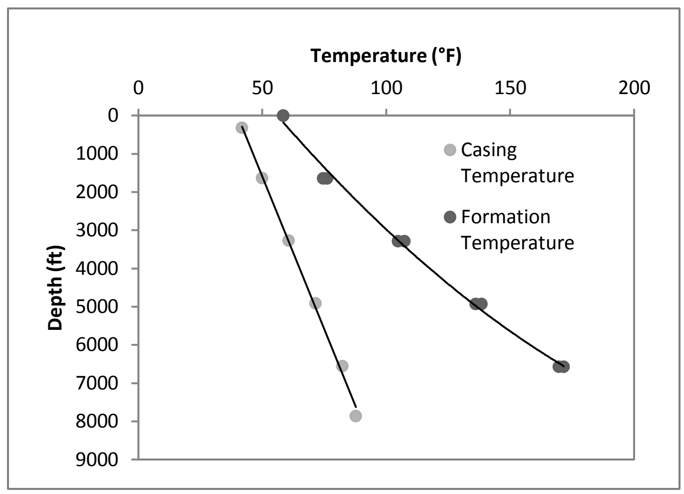


Figure 7: Wabamun formation and CO_2 injecting temperature profiles

The in-situ stresses for each condition were determined in the finite element model. The in-situ stress is a result of the cement column pressure exerted at the depth of interest. This pressure is dependent on if the annulus was open or closed during cementing. In this case the depth of interest is the Calmar shale at 6663ft. The inner casing pressure is dependent on the internal pressure of the wellbore, when a plug is set the internal pressure can be brought to hydrostatic by displacing the cement with fresh water, as done in the Wabamun area. The internal pressure may also be equal to the annular pressure in the case where a plug is not set or fails to set. In this scenario there is a U-tube effect in order to keep flow from occurring. The cement stress is the effective stress so the peak stress in the casing is equal to the stress in the cement minus the pore pressure. From the in-situ stresses, Figure 8 and Figure 9 show the radial and hoop stresses, respectively, along a vertical cut plane through the casing (dark grey), cement (light gray) and formation (green). For the open annulus scenarios, Figure 8 and Figure 9 show no risk of failure under the in-situ conditions.

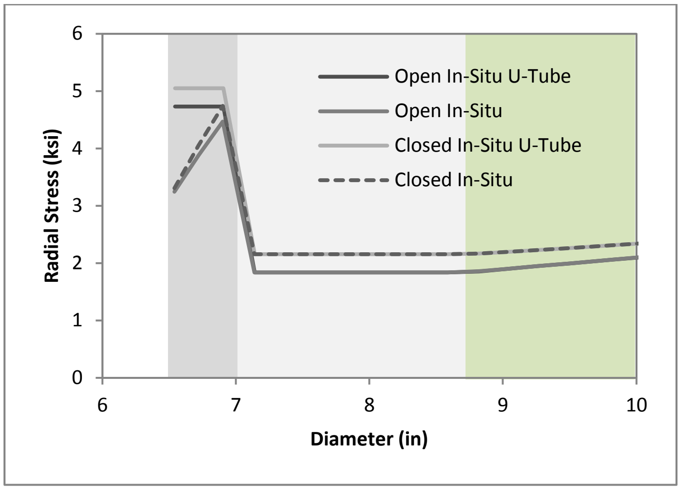


Figure 8: Wabamun onshore in-situ radial stresses

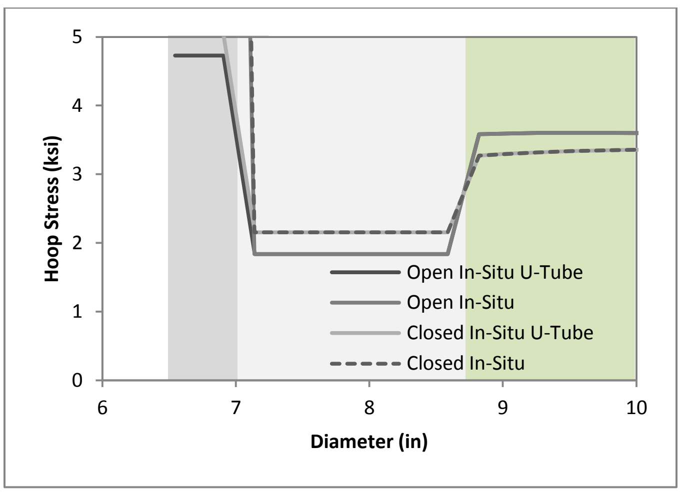


Figure 9: Wabamun onshore in-situ hoop stresses

Under the production conditions described in Table 6, the radial stresses in Figure 10 show that the U-tube conditions have the greatest potential of radial de-bonding. This is due to the larger pressure drop experienced from going from the higher pressure of the U-tube, compared to the hydrostatic condition, down to the production pressure. Figure 11 gives the hoop stresses for production under each scenario. Here the open annulus hydrostatic condition has the greatest potential of tensile failure compared to the other scenarios. All scenarios under production conditions are at no risk of failure.

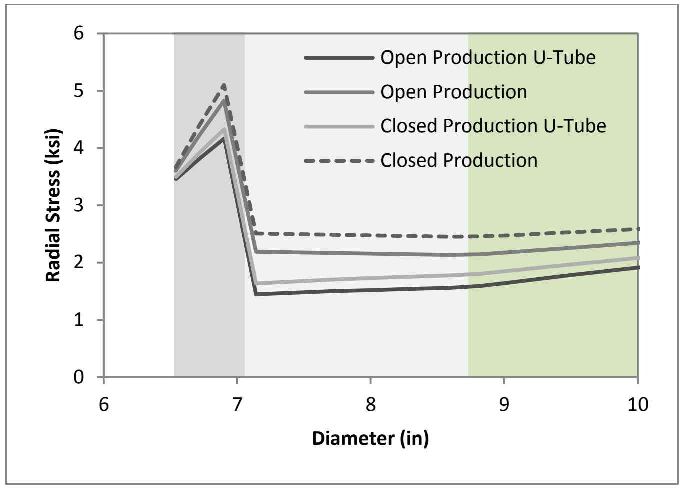


Figure 10: Wabamun onshore production radial stresses

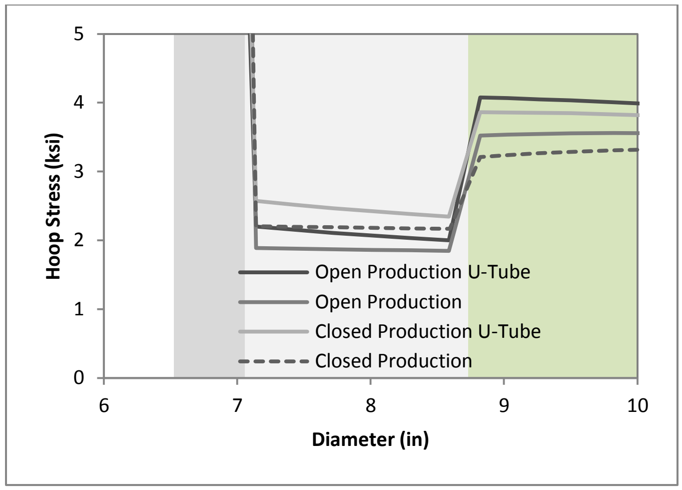


Figure 11: Wabamun onshore in-situ hoop stresses

When subjected to the depletion conditions described in Table 6, the radial stresses in Figure 12 show that the U-tube scenarios for open and closed annulus have the greatest potential of radial de-bonding. Additionally, the depletion conditions have a greater potential of failure than the production conditions, this is due to the decrease in wellbore pressure which is reduced as the reservoir is depleted. Figure 13 gives the hoop stresses for depletion under each scenario. Here the open annulus hydrostatic condition has the greatest potential of tensile failure compared to the other scenarios. Under depletion conditions the reduction in wellbore pressure has reduced the potential of tensile failure of the hoop stress compared to the production conditions. All scenarios under production conditions are at no risk of failure.

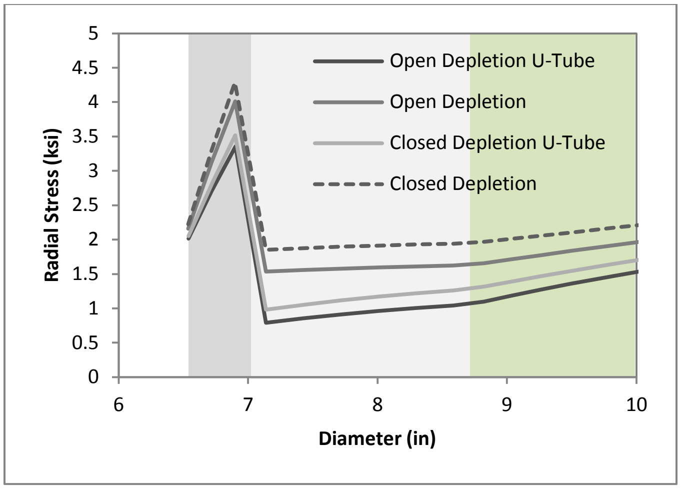


Figure 12: Wabamun onshore depletion radial stresses

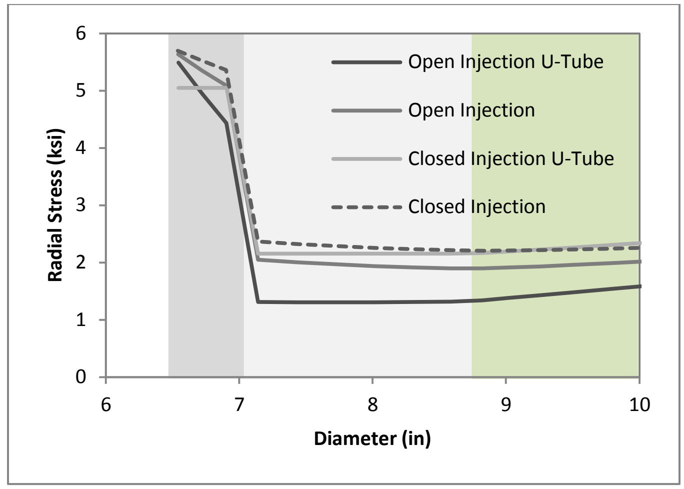


Figure 14: Wabamun onshore injection radial stresses

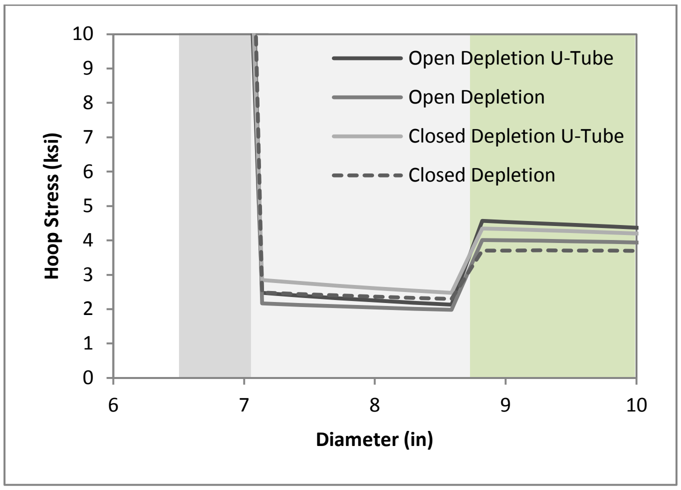


Figure 13: Wabamun onshore depletion hoop stresses

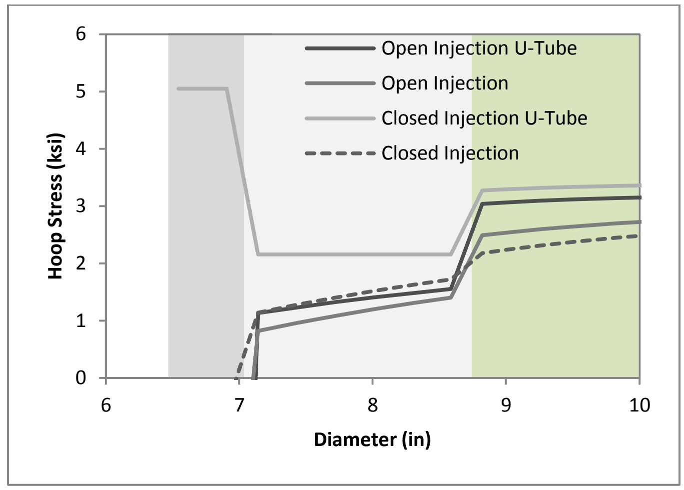


Figure 15: Wabamun onshore injection hoop stresses

Under the injection conditions described in Table 6, the radial stresses in Figure 14 show that the open annulus U-tube condition is at a much greater potential of radial de-bonding compared to the other scenarios. This is due to the higher in-situ stress in the cement column resulting in a smaller pressure increase experienced by this scenario compared to the other scenarios. Figure 15 gives the hoop stresses for injection conditions under each scenario. Here the open annulus hydrostatic condition has the greater potential of tensile failure compared to the other scenarios and the closed injection U-tube has the least potential of all the scenarios for tensile failure in the hoop stress. All scenarios under production conditions are at no risk of failure.

Offshore Case Study

This case study looks at a vertical offshore well which is described below in Figure 16. This well was drilled using a 16ppg oil-based mud and cemented using 17.5ppg cement. The casing of interest is the 9 5/8”, 70.3lb/ft, production casing which has a TVD at 10600ft. The hole diameter for the section is 12 1/4” and intermediate casing is a 13 3/8”, 84lb/ft, casing with a TVD at 7200ft.

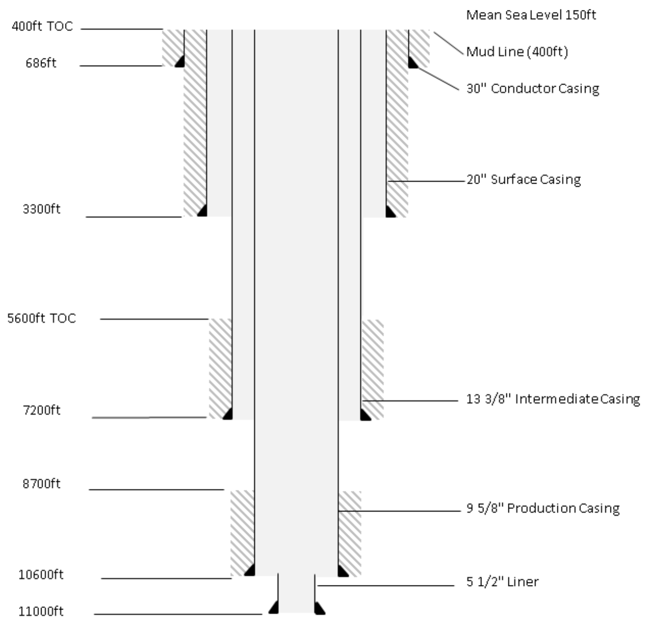


Figure 16: Offshore well design

The bottom hole temperature of 293°F and the temperature gradient will be linearly interpolated to the sea floor at 36°F. The circulation temperature was based on simulation of injection pressure temperature and it was found that for a surface fluid temperature of 41°F the bottom hole injection temperature would be 68°F. The circulation temperature was set to be the same. This profile is shown if Figure 17.

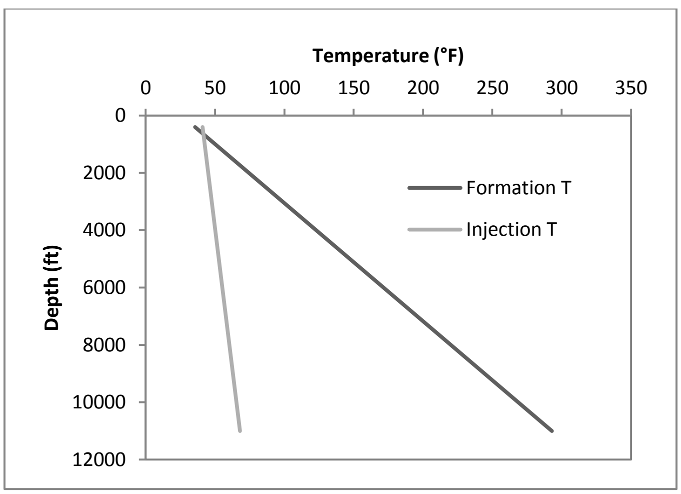


Figure 17: Offshore formation and injection/circulating temperature profiles

Open and Closed System

In the offshore well, the results of the changes from a planned cementing design are given in Figure 18. The density vs depth plot gives the pore pressure and fracture gradients for the well. The gradients are only plotted from the production casing shoe to the intermediate casing shoe. What can be found from this plot is that the use of an open annulus results in a pressure distribution throughout the column that has reduced to the pore pressure gradient. By the pressure dropping to the pore pressure gradient, formation fluid could begin to flow into the well. This flow into the well could lead to channeling in the cement, a poor overall cement job, or a fluid kick behind the annulus ultimately leading to a blowout. In the closed annulus situation the pressure increases due to the volume reduction of the annulus and the fluid volume increase resulting in high compressional pressures. The result of this compression increases the pressure so much that the bottom hole pressure gradient in the annulus is 27ppg. Again, the primary difference between these results and the Mitchell and Sweatman[4] results is that they assume the wellbore integrity is lost because of the crossing over the fracture gradient of the formation. However, in reality one would expect the fluid to leak off into the formation. It can be seen that once a fluid volume equal to the compression pressure has been leaked off the pressure in the column will decrease until it no longer is crossing the fracture gradient line. In this situation it was found that 11.2bbl of annulus fluid would have to leak off in order to move the column pressure inside the fracture gradient. The fluid loss overall is not a significant loss of volume and the integrity of the wellbore would remain intact.

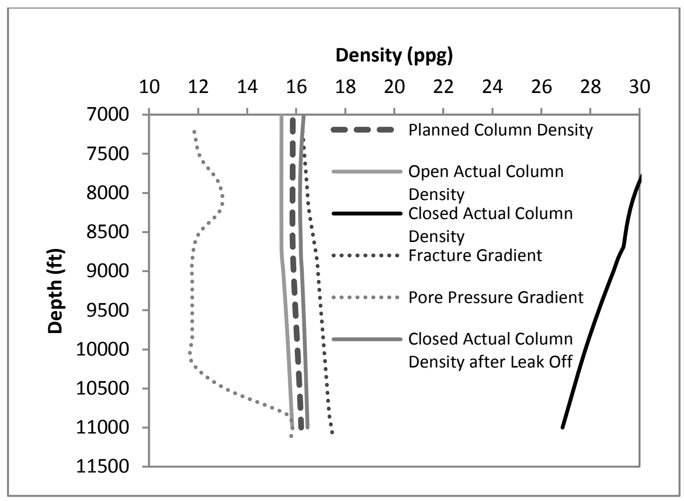


Figure 18: Offshore density plot of open and closed annulus conditions with fracture gradient and pore pressure gradient

Long Term Results

The simulation loading for the single casing at 10600ft is described in Table 7. Table 7 gives the formation's in-situ stresses and the production casing and hole diameters used in the model. The production casing cement is given as neat cement for the well. The cement pressure will be determined from the annular column density. The production cement is cemented to a depth of 8700ft, so the cement pressure will be based on 8700ft of oil-based mud of 16ppg and the interval of cement from 8700ft to 10600ft of neat cement of 17.5ppg. Additionally, the well will be loaded in a separate scenario with a U-tube pressure in which the pressure inside the casing is equal to the outside of the casing at the bottom of the hole.

As previously, this scenario would simulate a situation where the casing plug was not seated and equalizing pressures of the inner casing and outer casing was used to prevent flow. In the case, when a plug is set, the cement will be displaced with the oil based mud, 15.4ppg after temperature compensation.

The production temperature will be equal to the formation temperature at the bottom of the well in the perforated section at 11000ft with a temperature of 293°F. The production pressure will be equal to the bottom hole pore pressure equal to 9.14ksi. The depletion of the reservoir will be simulated with the same production temperature but a production pressure of half the bottom hole pore pressure.

The fracturing injection temperature and formation temperature are given as 67°F and 283°F, respectively. These values are determined from Figure 17 at a depth of 10600ft. The hydrostatic pressure of 4.60ksi is found by using a salt water density of 8.6ppg and pore pressure at 10600ft will be 7.65ksi. The fracturing injection pressure is 11.3ksi as to be able to fracture the reservoir section.

Table 7: Long term simulation conditions for offshore well

At 10600ft:		
Prod Casing ID	Prod Casing OD	Hole D
8.157”	9 5/8”	12 1/4”
In-Situ Vertical Stress	9.99ksi	
In-Situ Max Horizontal Stress	9.76ksi	
In-Situ Min Horizontal Stress	9.07ksi	
Production casing cement	Barite Cement	
Production Temperature	293°F	
Production Pressure	9.14ksi	
Depleted Temperature	293°F	
Depleted Pressure	4.57ksi	
Injection temperature	67°F	
Formation temperature	283°F	
Mud Pressure, 15.4ppg	4.60ksi	
Pore Pressure	7.65ksi	
Injection Pressure	11.3ksi	

The in-situ stresses for each condition were determined in the finite element program. The in-situ stress is a result of the cement column pressure exerted at the depth of interest. This pressure is dependent on whether the annulus was open or closed during cementing. In this case the depth of interest is 10600ft. The inner casing pressure is dependent on the internal pressure of the wellbore, when a plug is set the internal pressure can be brought equal to the mud density at elevated temperature, 15.4ppg, by displacing the cement with oil-based mud. The internal pressure may also be equal to the annular pressure in the case where a plug is not set or fails to set. In this scenario the pump pressure is increased to create a U-tube in order to keep flow from occurring. From the in-situ stresses, Figure 19 and Figure 20 show the radial and hoop stresses along the horizontal distance from the wellbore center (diameter) respectively, the open annulus scenarios are at the greater risk of radial de-bonding of the cement sheath from the casing or formation and tensile failure, but are at no risk under the in-situ conditions.

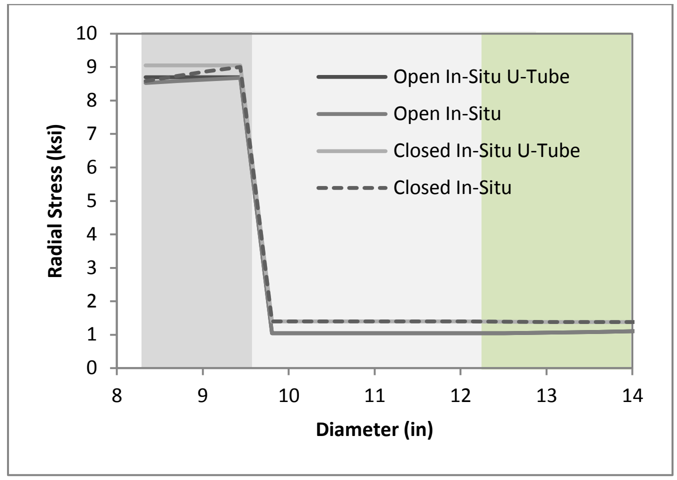


Figure 19: Offshore in-situ radial stresses

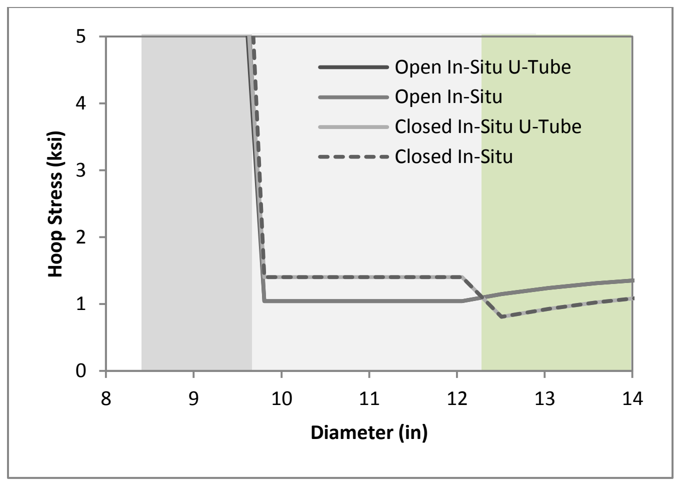


Figure 20: Offshore in-situ hoop stresses

Under the hydraulic fracturing conditions described in Table 7, the radial stresses in Figure 21 show that all scenarios are at a significant risk of radial de-bonding at the casing-cement interface. This is due to the large temperature change experienced from injecting the cool fluids from the surface, through the riser, and down to the reservoir formation. The temperature reduction from 283°F to 67°F causes tensile stresses to develop in the radial and hoop stress directions, ultimately leading to de-bonding if the temperature change is great enough. Figure 22 gives the hoop stresses for injection conditions under each scenario. Here the open annulus scenarios have a great risk of tensile failure. The hoop stress in the open annulus scenarios is at nearly 200psi of tensile stress, this means that if the cement is of poor quality at that depth or that the cement tensile strength is not greater than 200psi then the fracturing of the cement sheath will occur. If fracturing of the cement sheath occurs that would result in the loss of integrity of that well section, the casing would no longer be supported and wellbore fluid flow could not be prevented.

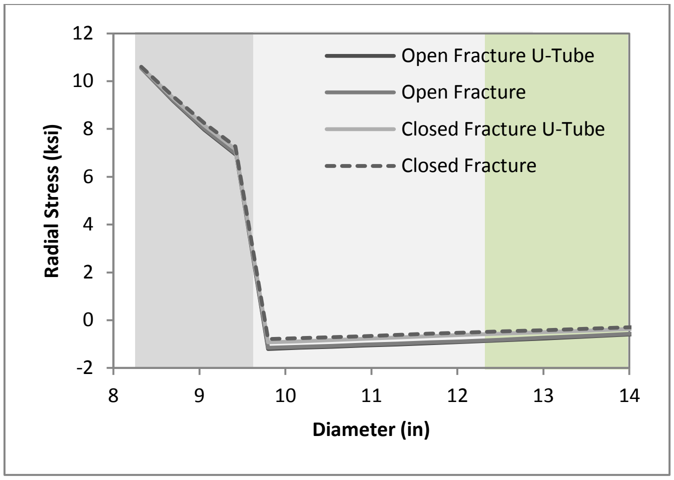


Figure 21: Offshore fracturing radial stresses

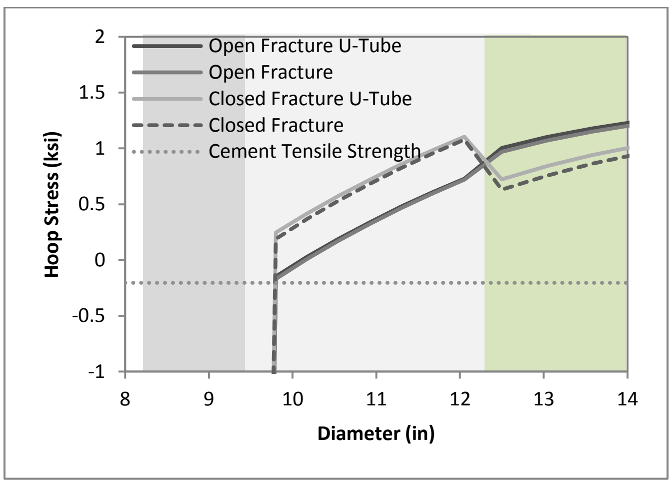


Figure 22: Offshore fracturing hoop stresses

Under the production conditions described in Table 7, the radial stresses in Figure 23 show that the open annulus conditions are at the greatest potential of radial de-bonding. Compared to the radial in-situ stresses the open annulus scenarios have slightly less risk and the closed annulus scenarios have slightly greater risk. Figure 24 gives the hoop stresses for production under each scenario. The closed annulus scenario has the greatest potential of tensile failure in the formation compared to the open annulus scenarios. If the formation were to fracture that would create a leakage path at the outside edge of the cement sheath. All scenarios under production conditions are at no risk of failure.

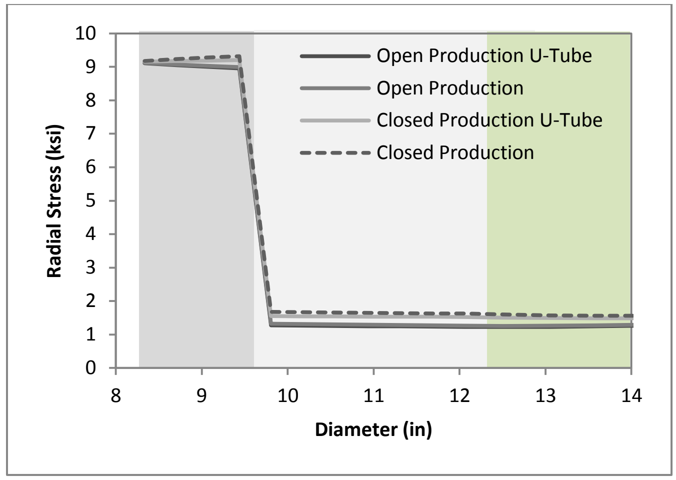


Figure 23: Offshore production radial stresses

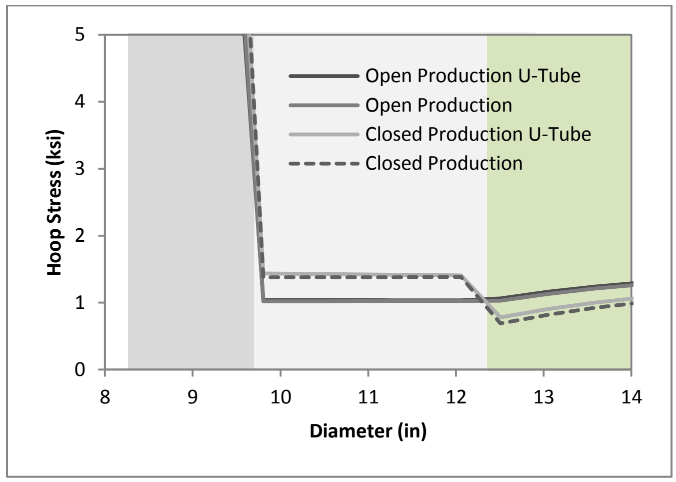


Figure 24: Offshore production hoop stresses

When subjected to the depletion conditions described in Table 7, the radial stresses in Figure 25 show that the open annulus scenarios are at risk of radial de-bonding. If radial de-bonding were to occur at the casing-cement interface then the wellbore fluids could leak into the annulus and possibly to the surface. Additionally, the depletion conditions are at a greater risk of de-bonding than the production conditions, this is due to the decrease in wellbore pressure which is reduced as the reservoir is depleted reducing radial stress. Figure 26 gives the hoop stresses for depletion under each scenario. Here the open annulus conditions have the greatest potential of tensile failure compared to the other scenarios. Under depletion conditions the reduction in wellbore pressure has reduced the potential of tensile failure of the hoop stress compared to the production conditions. The open annulus conditions are at a high risk of radial de-bonding in under depleted conditions, the radial stress is very close to tensile stresses which means that any slight variations in density or pressures could lead to radial de-bonding at the casing-cement interface.

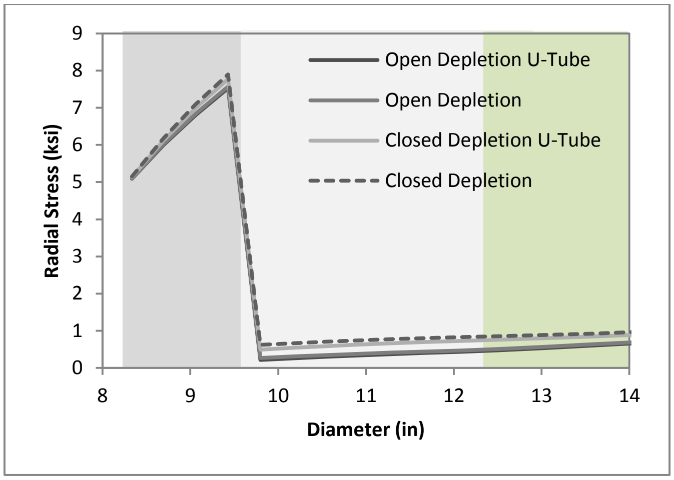


Figure 25: Offshore depleted radial stresses

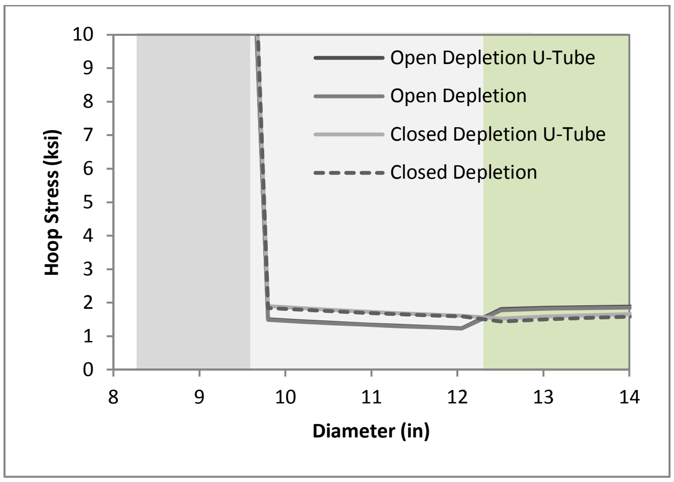


Figure 26: Offshore depleted hoop stresses

Discussion

Short Term Integrity

When the pressure in the wellbore becomes greater than the fracture gradient it is not sign of loss of overall wellbore integrity. Under the conditions where the highest crossover occurs below the previous casing shoe and above the cement top the pressure and excess fluid may leak off into the formation resulting in the pressure reducing until the fracture gradient is no longer crossed. If the greatest crossover of the pressure curve and fracture gradient were to occur below the cement top then there would be an expected loss of cement slurry resulting in a reduction of cement sheath integrity above that point.

If the annulus pressure were to drop below the pore pressure gradient then there is a significant risk of cement sheath integrity loss. The risk of channeling and fluid kick become very high and the integrity of the well is compromised. In a situation where the pressure in the annulus drops in a U-tube well there is a risk that the fluid in the wellbore may flow into the cement sheath in the annulus. This would be caused by the reduction of pressure in the annulus and the higher pressure caused by the pump. While the pumps would eventually correct to the proper U-tube pressure, there may be a risk of channeling or poor cementing at the casing shoe.

Long Term Integrity

In the Wabamun area the closed annulus U-tube scenario had the overall lowest potential risk of all the scenarios, while the open annulus hydrostatic scenario had the greatest potential risk. There was no indication of failure in any of the Wabamun scenarios but the model was run under elastic conditions. If cycling were to occur under these conditions the cement sheath would begin to fatigue and the tensile stresses would occur for the conditions with the lowest radial and hoop stresses first.

In the offshore well it was found that the open annulus scenarios had the greatest risk of failure and may even result in failure under elastic loading during fracturing and depleted reservoir conditions. All scenarios will result in de-bonding under the fracturing conditions. This means that during the hydraulic fracturing job that the fluid injected into the formation can travel between the casing and the cement sheath. The depth that these fluids can travel is not described but the potential is that these fluids could reach the surface, which could cause catastrophic problems for the cased wellbore integrity. The greatest probability of a secure offshore well in this case study is a closed annulus using either the drilling mud or a U-tube as the fluid inside the casing during cementing.

Conclusions

This paper discusses the effects of open and closed annulus cement jobs on the short term and long term integrity of the well. The casing and formation displacement calculations were described as well as the fluid expansion and compression. Staged finite element simulations looked at long term integrity by simulating in-situ, fracturing, production, depletion, and injection conditions.

The results show that, for the two cases studied here, a closed annulus cement job will result in a more resilient cement sheath. While there may be a pressure greater than that of the fracture gradient the fluid pressure would leak off into the formation with similar damage to a LOT. Fracturing of the well can result in many long term problems due to the high risk of de-bonding and tensile fracturing of the cement sheath. Overall there are a variety of complications that can occur if the cement pressures are not monitored and the cement sheath is not designed for the life of the well. The long term simulations must also be updated based on the result of the primary cementing job.

When thermal effects on the fluid and annulus are to be accounted for there are two general conclusions that can be made from these results. The first conclusion is that in a closed system it would be expected that the pressure will increase in the annulus and therefore the pressure will leak off into the formation. The resulting annulus column pressure would be equal to the first intersection with the fracture gradient. The second conclusion is that in an open annulus the fluid density change with temperature controls the annular pressure. The change in height of the cement column with annulus volume change is negligible compared to the fluid expansion.

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Nomenclature

E = Young's modulus
v = Poisson's ratio
μ = Micro (10^{-6})
ε = Strain
α = Linear thermal expansion
u = radial displacement
T = temperature change
$C1$,$C2$ = Integration constants
P_b = pressure change in the annulus
P_a = pressure change inside of the casing
r = Radius of interest
r_a = Inner casing radius
r_b = Outer casing radius
r_c = Inner formation radius
β = Thermal volumetric expansion
Δp = Change in pressure
ΔV = Change in volume
V = Volume
k_T = Isothermal compressibility
x,y,z = Cartesian coordinates
ρ = Cement slurry density
To = Tensile Strength
ID = Inner diameter
OD = Outer diameter
D = Diameter

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