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DESIGN OF DEEP GEOTHERMAL WELL USING THE AFRICAN UNION CODE OF PRACTICE FOR GEOTHERMAL DRILLING: A CASE STUDY OF OLKARIA, KENYA

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ABSTRACT

This report presents the design of a high-temperature deep geothermal well in Olkaria field, using the revised code of practice for deep geothermal wells, *The African Union Code of Practice for Geothermal Drilling* (AUS, 2016), with a focus on well OW-49. Furthermore, this study will also provide a well design for a hypothetical 4500 m deep geothermal well that will serve as a guideline for future deep drilling projects. The well, OW-49 was drilled to a depth of 3650 m and designed using the New Zealand Standard code of practice for deep geothermal wells (NZS 2403:1991) (NZS, 1991). A review of the well design was done using the revised code basing the design considerations on the exact conditions of the well. Design calculations on casing loads were done to establish the best casing selection for the well by first establishing whether the current well casing design is adequate in terms of strength. The current casing design for well OW-49 comprises of a 20″, 94 lb/ft K55 surface casing, a 13⅜″, 54.5 lb/ft K55 anchor casing and a 9⅝″, 47 lb/ft K55 production casing. The revised design results conservatively in deeper casings and one additional casing string. Additionally, determination of the most suitable wellhead for the well was done. Finally, the report gives the well design for a hypothetical 4500 m deep geothermal well with an emphasis on casing specifications, drilling programme, cementing programme and wellhead specification.

1. INTRODUCTION

Drilling of geothermal wells in Olkaria, Kenya has greatly accelerated in the recent past due to the need to meet the country's ever growing demand for energy, in line with vision 2030 of the government of Kenya. The vision envisages to increase the generating capacity to 5000 MWe by 2030. The Kenya Electricity Generating Company Limited (KenGen) has formulated a strategy to generate 2,500 MWe to the national grid by 2025, of which geothermal energy is a major component, constituting 2,410 MWe.

The well design for the wells drilled in Olkaria is a regular diameter type for production and re-injection wells. The New Zealand Standard code of practice for deep geothermal wells, NZS 2403:1991 (NZS,

1991) has been the main code of practice used in the designing of these wells. However, this standard was replaced in 2015 with a revision, NZS 2403:2015 (NZS, 2015). The African Union Standard (AUS, 2016) code of practice for geothermal drilling is another standard that came into force in 2016, incorporating the revised New Zealand standard, NZS 2403:2015. This standard is specifically tailor-made for the countries of Eastern Africa.

A typical production well is drilled to a depth of 2000-3000 m and can either be drilled vertically or directionally. There has been growing interest from scientists at Olkaria to investigate whether there is a geothermal resource beneath 3000 m and an attempt was made by drilling well OW-49 to 3650 m. The well was drilled in 2014 before the African Union Code of Practice (AUS, 2016) came into force and results from this well confirmed the existence of geothermal energy below 3000 m, therefore the resolve is to drill deeper wells at Olkaria.

This study will use the African Union Code of Practice (AUS, 2016) for geothermal drilling to review the design of OW-49 using the stratigraphy and exact reservoir conditions identified as a reference well and thereafter design a hypothetical 4500 m vertical well as a guideline for future deep geothermal well drilling at Olkaria.

2. LITERATURE REVIEW

2.1 Geothermal well design

Devereux (1998) describes well design as a stepwise process undertaken by an engineer before drilling to define the desired final status of the well. In the well design phase due consideration is given to:

a) Subsurface conditions between the wellhead and well target, mostly the geological formations and reservoir conditions of the area under drilling;
b) Directional requirements;
c) Determination of safe well casing shoe depths for each casing string;
d) Selection of casing diameters, connections, materials and performance properties; and
e) Determination of wellhead specifications and selection of component materials.

A good well design yields a well that is safe to operate and with a reasonable long life. Numerous efforts to improve on well design have been done in recent years through the revision of the existing standard, which has led to the creation of the New Zealand NZS 2403:2015 Standard (NZS, 2015) and the African Union Code of Practice for Geothermal Drilling (AUS, 2016).

2.2 Geology

The geological formation of an area under drilling provides key information required in the well design process, specifically on the rock strata, rock competency, the nature of rock alteration, faulting or fracturing, fracture pressures and lithologies that are potentially composed of unstable formations. Figure 1 shows the geology, well design and depths of the casing strings of OW-49.

*0-40 m: Pyroclastic***.** This zone is comprised of a layer of loose, unconsolidated clastic materials, consisting of soil, pumice, tuff, obsidian, rhyolitic glass, volcanic ash and lithic rock fragments. This zone is a soft formation and the likelihood of it caving in is high.

40-500 m: Rhyolite. This formation is mainly rhyolitic lavas with minor intercalations of tuff. This formation is medium hard and is generally massive and dense. Minor losses may occur and the formation is competent.

500-800 m: Trachyte. This zone is mostly trachyte dominant. The rock in this zone is medium hard to hard and displays a moderate intensity of alteration with a few loss zones observed.

800-3300 m: Trachyte, tuff and basalt. This zone is mostly trachyte with tuff and basalt intercalations signifying different episodes of magma fractionation. This zone is moderately altered and massive with circulation losses expected. The formation is medium hard, showing moderate to high intensity of alteration.

3300-3650 m: Trachyte with syenitic and granitic intrusion. The rock mainly consists of trachyte. Mostly syenitic and granitic intrusions occur in this zone. Formation is massive, relatively fresh and competent. Alteration is slight and a minimal circulation loss is expected.

An alteration mineralogy report provides information on the indicative formation temperature that influences the decision on where to set the production casing during the drilling process.

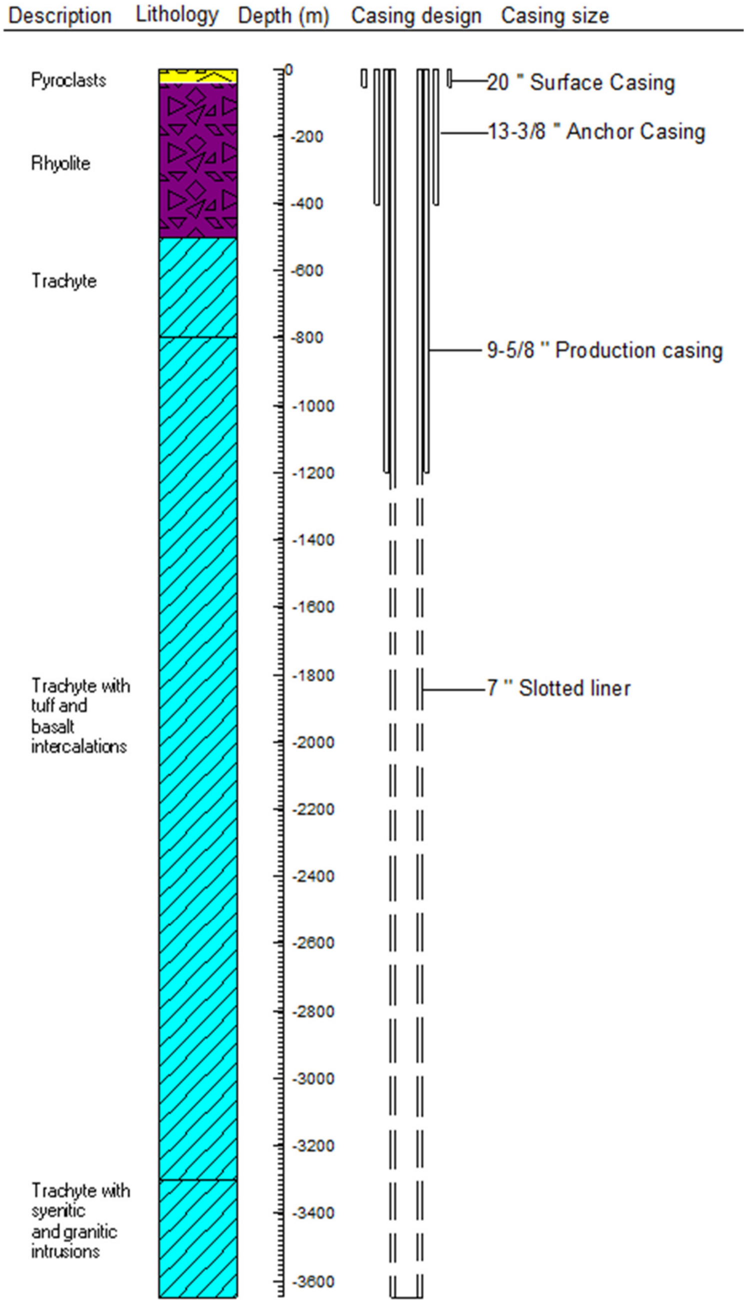

FIGURE 1: Well design of OW-49 and geological Cross-section (KenGen, 2014)

2.3 Casing design

Casings are designed to primarily allow a well to be drilled safely, by providing the structural integrity of the well against forces imposed during drilling, and to meet the purpose of the well without requiring a workover throughout the well's life. For economic reasons, the casing design should be done in a cost effective manner without undermining safety, since the cost of the casing contributes significantly to the overall cost of a well.

A good casing design for a geothermal well should account for the anticipated conditions during the drilling and operation of the well, which may compromise the safety and eventually the life span of a well. This is done to ensure that the casing selected for a particular well has a considerable margin of strength to accommodate anticipated stress regimes at all depths throughout the well. Factors considered include (AUS, 2016):

- External and internal loads that may lead to casing failure;
- Anchoring of wellheads during drilling and operation of the well;
- Resistance against erosion, corrosion or fracturing;
- Safe containment of well fluids;
- Control against subsurface aquifer contamination; and
- Resistance against hydrogen embrittlement in environments rich in hydrogen sulphide gas.

Casing strings are a major component of the well design. They are comprised of several concentric steel casings that are run in a well and held in position by a cement bond formed between the casing wall and the well formation or between two casing strings. The steel casings are selected from API spec 5CT and API spec 5L. Under the API standards, casings are classified according to manner of manufacture, grade of steel, joint type, length range and wall thickness. The casing grade defines the strength of casing steel against burst and axial tensile loads, while the strength against collapse is mainly attributed to the wall thickness of the casing (Finger and Blankenship, 2010). It is also a requirement that casing sizes selected should provide adequate clearance between two casing strings to allow satisfactory cementing.

The casing joints are normally connected to one another by threaded connections, though there are also welded casing connections specifically for large diameter casings. The selection of the connection may be governed by strength requirements, cost and leak resistance. API buttress threads are the most commonly used but there are also special cases where premium connections such as Tenaris Blue and Metal One Geoconn are used, as was the case for the Iceland Deep Drilling Project (IDDP-2) in Iceland.

A typical geothermal well has the following casing strings:

- *Conductor pipe:* Runs to a shallow depth and offers a firm foundation platform. It provides protection against the washing out of the loosely held top formation.
- *Surface casing:* Runs to provide protection against collapse of weak formations and for prevention of blowouts at shallow depths. It also supports the blowout preventer for the safe drilling of intermediate holes.
- *Anchor casing:* Runs deeper with the primary purpose of resisting forces imposed by kicks, circulation losses and problematic formations. It also supports the blowout preventer for facilitation of safe drilling of the subsequent sections of the wellbore and later the final production wellhead. The casing can also serve as the production casing in large diameter well design.
- *Production casing:* This casing provides a barrier between the cold and hot zone of the well. It also offers a conduit for reservoir fluid movement to the surface.
- *Liner casing:* This is a slotted or perforated casing that is set inside the production casing and allows flow of reservoir fluid into the well.

The casing program for well OW-49 is comprised of a 20″ surface casing, 13⅜″ anchor casing, 9⅝″ production casing and 7″ slotted liners. The same program will be followed for the well design in this report.

2.4 Casing depth selection

The decision to determine the minimum casing depth for a high-temperature well is greatly influenced by information gathered from nearby wells on temperature and pressure versus depth. The other criterion used are:

- Based on the New Zealand Standard NZS 2403:2015 (NZS, 2015): The minimum casing shoe depth is calculated to be the depth where the formation has sufficient effective containment pressure equal to the maximum design pressure expected in the next open hole section. This is

the same principle applied in the African Union Code of Practice for geothermal drilling (AUS, 2016).
- Boiling point curve method that is commonly used in Iceland. It assumes the same bottom hole pressure from the boiling point curve of an adiabatically boiling column of water. The curve acts as the lower margin for the determination of minimum casing depth.

2.5 Wellhead design

A permanent wellhead is a major component of a geothermal well. It is located at the surface and its purpose is to contain the maximum fluid pressure and temperature exposure from a well. It comprises of a master valve, casing head flange, expansion spool, gaskets, kill valves and bolts, whose design specifications should conform to API Spec 6A or API 6D. A good wellhead design dictates that the materials used for the construction of the wellhead components should be suitable for use under all expected service temperatures and pressures. The master valve is often selected from pressure ratings of the flanges selected which should conform to ANSI B16.5 and to API 6A.

Factors considered during wellhead design include:

- Protection against corrosive environment;
- Reduction of wellhead rise and fall during operation;
- Surface pipeline attachment to the wellhead; and
- Orientation of waste sumps to the wellhead equipment.

Wellhead selection is covered in chapter 6.4.

3. DESIGN CONDITIONS

Well temperatures and pressures at depth form the basis of the selection criteria for the number of casing strings, setting depths, casing material, drilling fluid and cementing program.

3.1 Design premise for OW-49

The design conditions are based on the well test results of OW-49, which describe the exact reservoir conditions of the well. The shut in temperatures and pressures for the different heating periods are plotted against depth with the boiling point depth (BPD) curve and the corresponding hydrostatic pressure profile also displayed.

The temperature in a static well is assumed to follow the boiling point depth curve (BPD) down to the critical point, which is at around 3500 m depth, depending on the pressure balance in the system. Similarly, the pressure assumes a hydrostatic column of pure water at the BPD down to the depth of the critical point.

3.2 Design premise for a hypothetical 4500 m deep geothermal well

The conceptual model for Olkaria field has described the lithology of the field to be mainly made of pyroclastics, rhyolite, basalt, trachyte and granitic formations. For the determination of the fracture pressure of the hypothetical well, a similar lithological profile of OW-49 will be assumed to a depth of 3650 m. Beyond that depth, the formation will be assumed to comprise of granitic rock.

Hole (2008), states that for cases where there is no clear understanding of the reservoir fluid, an assumption of the reservoir fluid is approximated to a column of water at boiling temperature throughout its depth. However, the depth should be taken from the water level, i.e. a pressure balance of the system. The water level for Olkaria field is at approximately 300 m depth, which forms the basis for the boiling point for depth (BPD).

It is also assumed that the temperature of the well will continue to increase with depth following the BPD curve to the critical point of 374.15°C and 221.2 bar at a depth of around 3500 m, although this depth will be adjusted according to the pressure balance of the system. Similarly, the pressure will also follow the hydrostatic condition to the critical point. Due to a lack of firm guidance as to what trajectory the temperature would take below the critical point, one scenario is to assume a 100°C/km gradient (Thórhallsson et al., 2010).

3.3 Minimum casing depths for OW-49

The pressure plots for the different heating periods were plotted in order to determine the point where pressures in the well remained unchanged, commonly known as the pivot point/depth which forms the basis for this well design. Temperature and pressure logging runs for OW-49 were done after heating periods of 6 days, 15 days and 83 days from the day the well was capped with an ANSI class 900 master valve. The plots obtained from the results for temperatures and pressures for the individual runs are shown in Figures 2, 3, and 4.

The pivot point/depth was found to be 160 bars at 2600 m from the pressure profiles, as shown in Figure 5. The hydrostatic pressure curve at boiling point was adjusted to pass through the pivot point in order to obtain a curve representing the boiling pressures in the well. Equally, the boiling point depth curve was adjusted to show the corresponding temperatures for the hydrostatic pressure curve. According to

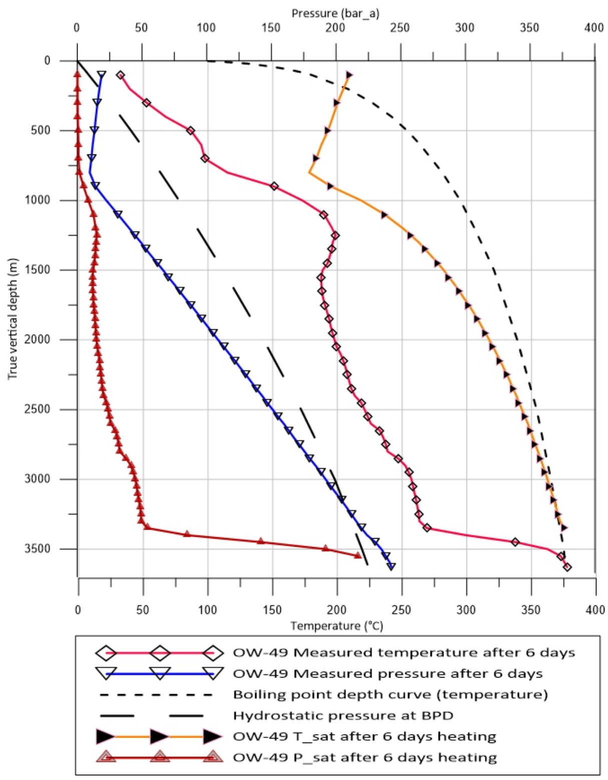

FIGURE 2: OW-49 temperature and pressure profiles after 6 days of heating

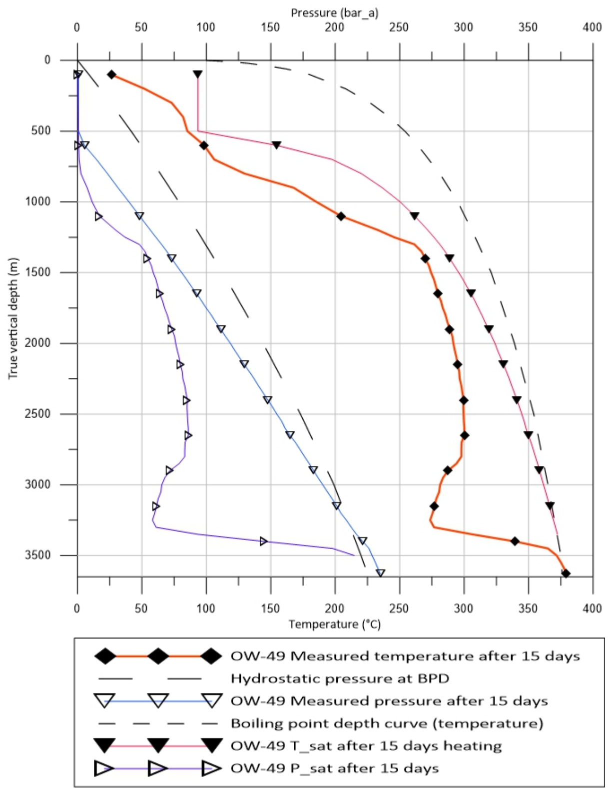

FIGURE 3: OW-49 temperature and pressure profiles after 15 days of heating

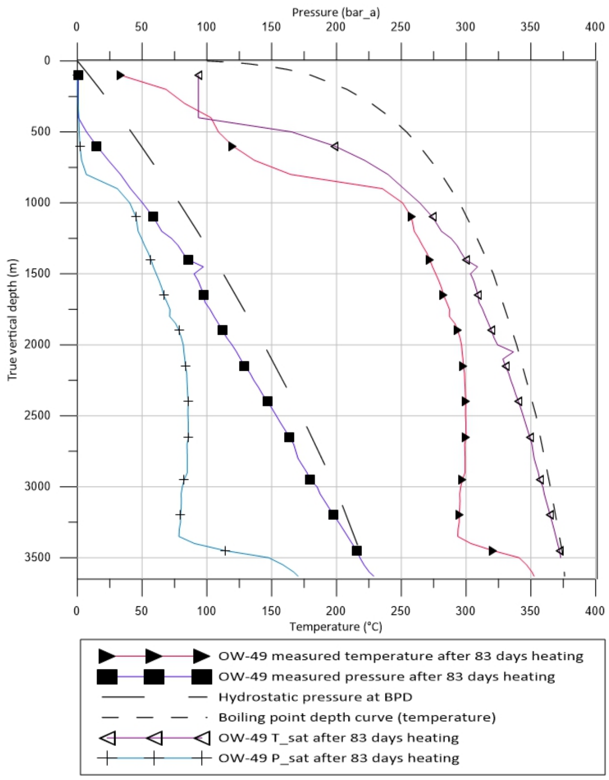

FIGURE 4: OW-49 temperature and pressure profiles after 83 days of heating

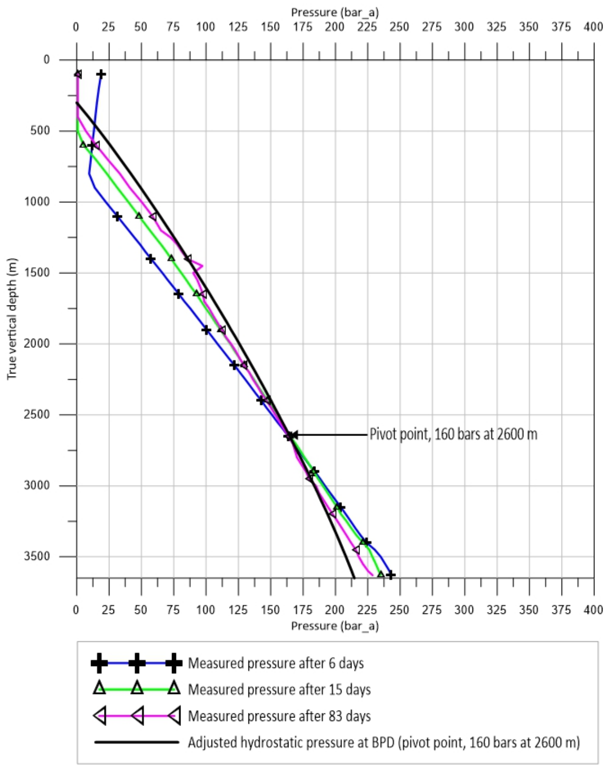

FIGURE 5: OW-49 pressure profiles and adjusted hydrostatic pressure at BPD

the African Union code 2016, the resulting pressure curve gives the lower boundary for the determination of the minimum casing depths of the well.

The upper boundary, which is represented by the effective containment pressure (fracture pressure) is computed using the Eaton formula (African Union, 2016) described in Equation 1 (for definitions of parameters, see Nomenclature at the end of this report),

$$P_{frac} = P_f + \frac{v}{1-v}\left(S_v - P_f\right) \tag{1}$$

where

$$S_v = \rho \times g \times h \tag{2}$$

Figure 6 shows the minimum casing determination of well OW-49 using the African Union code (AUS, 2016). It is established that the minimum casing depth for the production, anchor and surface casings should be set deeper at 1500 m, 800 m and 400 m, respectively. However, the casings were set at 1202 m, 404 m and 55 m. This is a clear indication that the new revision of the standard results in deeper casing depths (Ngigi, 2015). It is important to ensure that the colder part of the reservoir is sealed off from the hotter part of the reservoir to avoid mixing of high-enthalpy fluids with lower-enthalpy fluids, which has resulted in problems such as corrosion in the past, examples of this are from Iceland (Karlsdóttir and Thorbjörnsson, 2013) and Los Humeros in Mexico (Gutiérrez and Viggiano, 1990). Consequently, the casing design of deeper casings becomes more demanding. It is also worth noting that a change in depth selection of one casing affects the depth selection of the other casings.

3.4 Minimum casing depths for the 4500 m deep well

Figure 7 shows well pressure results for superheated/saturated steam column from 4500 m along with the maximum design pressure gradient and an estimated formation fracture gradient. The formation

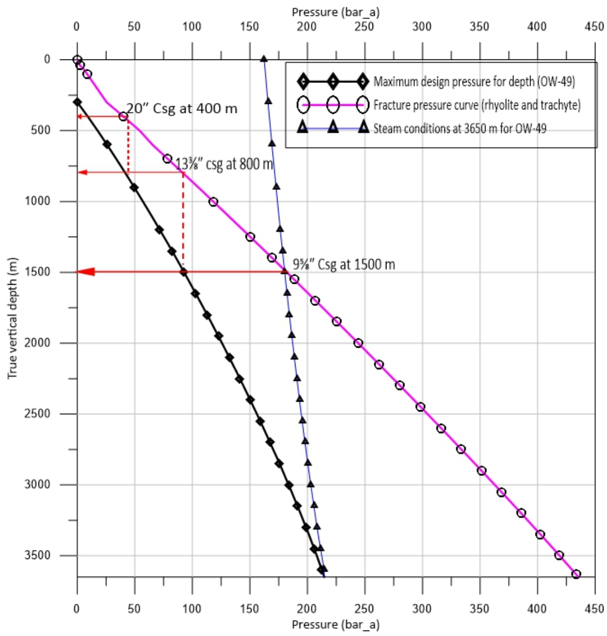

FIGURE 6: Minimum casing depth determination for OW-49 using the African Union Standard (AUS, 2016)

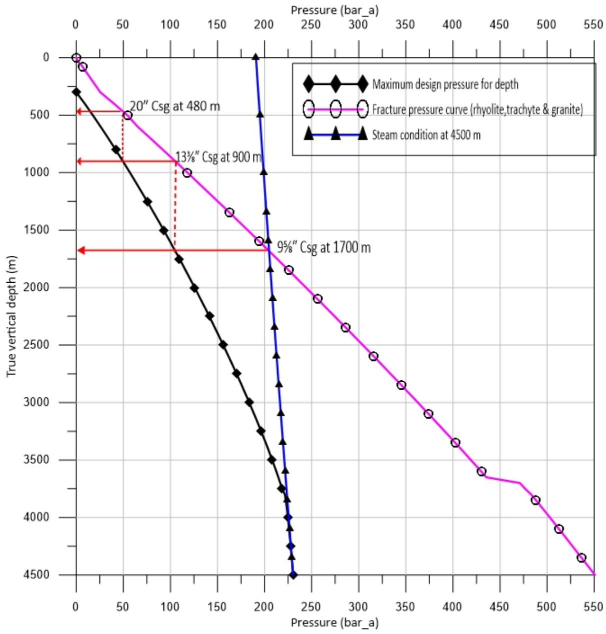

FIGURE 7: Minimum casing depth determination for the 4500 m deep well

fracture gradient is calculated using the Eaton formula. The pressure below the critical point is calculated by assuming a temperature gradient of 100°C/km.

It is established that the minimum casing depth for the production, anchor and surface casings should be set at 1700 m, 900 m and 480 m respectively. In addition, a conductor casing should be incorporated in the design to enable safe drilling for the surface casing by providing protection against the collapse of the top sections of the well.

4. DRILLING PROGRAMME

A drilling programme provides a clear guideline on the best and safest practices of drilling a geothermal well. However, modifications in the programme can be made during the drilling process to suit the prevailing conditions. Drilling challenges experienced over the years while drilling geothermal wells at Olkaria field has resulted in a design of drilling programmes that are suited for the field. The following guidelines are based on the experience in the field.

4.1 Drilling fluids and hydraulics

Drilling fluids are selected according to reservoir pressures and temperatures and the planned drilling techniques. They include water, water based bentonitic or polymer muds, aerated water or mud, stiff foam, mist or air.

4.1.1 Conductor casing hole: 36"

The conductor hole will be drilled using a 36" tri-cone bit with water based mud. Drilling mud at low pumping speed should be used during spud-in of the well in order to prevent massive washouts. Cleaning of the well bore requires high flow rates of the drilling fluid which cannot be achieved for this section due to the large cross section area of the well. For this reason, the drilling mud should be adjusted to a higher density and viscosity as a measure to achieve the minimum hole cleaning requirements. For a case where circulation losses cannot be regained with loss of circulation materials, drilling blind with water and mud with high viscosity gel sweeps at every connection shall be done.

4.1.2 Surface hole: 26"

The surface hole will be drilled using a 26" tri-cone bit with water based mud. Use of loss of circulation materials is recommended should loss of circulation of drilling fluid be experienced. Drilling blind is also recommended should the loss of circulation persist, however, sweeps of mud with high viscosity gel should be done at every connection.

4.1.3 Intermediate hole: 17½"

The intermediate hole will be drilled using a 17½" tri-cone bit with bentonite mud at a flow rate of 3600 l/m. Drilling with water and high viscosity gel sweeps at every drill pipe connection is recommended where major circulation losses are encountered.

Foam is to be utilized as the drilling fluid in this section in the event of a hole cleaning problem. It is anticipated that temperatures in this section are relatively low which means that the water inflow conditions allow the establishment of a stable foam circulation. An initial fluid concentration of 0.5% soap is recommended but can be increased to 1% for a case where severe heating or poor hole cleaning is noticed.

4.1.4 Production hole: 12¼"

The production hole will be drilled using a 12¼" bit using water-based mud that is chemically treated to maintain the desired viscosity, gel strength and water loss properties at a flow rate of 3900 l/m. Stiff foam is recommended in case of major circulation losses. The drilling fluid can be switched to aerated fluid should it become impossible to drill with foam due to high temperatures.

4.1.5 Main hole: $8^1/_2$"

The main hole will be drilled using $8^1/_2$" polycrystalline diamond bit using aerated water and foam at a water flow rate of 3300 l/m and 1800 scfm. Down hole temperatures may be high and the temperature of the ingoing fluid should be maintained at a maximum of 40°C, which is the maximum recommended operating temperature for the pumps. The pH of the circulating fluid should be maintained at about 10 using caustic soda.

4.2 Well control

It is imperative to always keep the formation fluid pressures in check while drilling a geothermal well as a safety measure against blow outs that may develop from a kick. Kicks arise in situations where the formation fluid pressures exceed the drilling fluid pressure and may result in a blow out if not controlled. Consequently, it is important to maintain the right mud weight where drilling mud is used as the drilling fluid.

Blow out preventers (BOPs) are the second barrier put in place in well control. For this well design, the 29½″, 21¼″ and 13⅝″ BOPs will be used for all phases of drilling following the cementation of the conductor casing.

The 29½″, 500 psi rated BOP stack shall be installed after the cementing of the 30″ conductor casing and shall be used while drilling the 26″ section of the well. The 21¼", 2000 psi rated BOP stack consisting of a single blind ram and an annular preventer shall be installed after the cementing of the

20″ casing. Both the ram and the annular BOP shall be tested for pressure leakage at 300 psi for 10 minutes before drilling out cement at the shoe. This BOP shall be used while drilling the 17½″ section of the well.

The 13⅝", 3000 psi rated BOP stack consisting of a 3000 psi rated annular and double gate ram preventers will be installed after the cementing of the 13⅜″ casing. The rams shall be tested for pressure leakage at 200 psi and 1000 psi for 10 minutes each. A pressure test of the annular preventer to 1000 psi for 10 minutes will also be done. This BOP shall be used while drilling the 12¼″ and 8½″ sections of the well.

4.3 Casing running procedure

Running of casing shall be done after it has been established that the hole is free from any form of obstruction or cuttings at the bottom of the well that may otherwise hinder the smooth flow of the process. The running of the casing shall entail:

1. Sequential running of casing starting with the guide shoe, float collar and the rest of the casing. A thread lock shall be used at the bottom three joints, whereas a casing dope will be used for the rest of the casing connections.

2. Centralizers shall be placed as follows:
   - One centralizer at the middle of shoe joint;
   - One at 2 m above the float collar; and
   - One after every three casing joints to surface.

3. Running of casing shall be done at a relatively safe speed but slower near the bottom.

4. The last three joints shall be run slowly and make-up of the landing joint with a circulating swage and a chicksan hose shall be done.

5. Circulating through the casing shall be done to clean the well bore.

6. The casing shall be landed at the correct height with a landing joint and properly centralized with the rotary table.

4.4 Cementing program for the 4500 m well

The design of a cementing programme seeks to ensure that the total length of the annulus outside the casing is completely filled with good quality cement. For this well, the conductor casing, surface casing, anchor casing and production casing will be fully cemented back up to the surface. Calculation of slurry volumes for each casing string shall provide allowances for over gauge hole and losses to the formation.

There are several cementing methods that are commonly used in cementing, namely:

Single stage cementing: This involves pumping a determined amount of cement slurry through the casing and displacing it out to the annulus through the casing shoe. Two plugs, namely the bottom and top plugs held in a cementing head are used in this method. The bottom plug, which is made of a rapturing membrane, is released first before pumping of cement slurry commences and later the top plug is released before pumping of the displacing fluid starts. A limiting factor with this method is that the cement volume cannot be adjusted where cement slurry returns are not received at the surface after displacement.

Multiple stage cementing: With this method the placement of cement slurry around the casing string is done in stages at selected time intervals. This is most applicable for cases where there is limited pumping time due to high temperatures in the well, high risk of formation fracture due to high hydraulic pressure head of cement and for cases where only a certain portion of the well requires cementing. Regular two stage, continuous two stage and three stage cementing are the three commonly used multistage methods.

Inner string cementing: This method involves pumping cement slurry through a drill pipe string attached to either the float collar or casing shoe by means of a stab-in receptacle. It is commonly used to cement large diameter casings run below 1000 m. A major drawback of this method is that too much time is spent on running the cementing string to and from the well in long casing strings. It can also generate high external pressure at the casing shoe.

Reverse circulation method: The cement slurry is pumped through the annulus and displaced into the casing by use of a drilling fluid. It is commonly used where lost circulation zones or fragile formations occur near the shoe, but cement is required to seal off an upper interval. This method has several advantages which include reduced hydraulic horsepower, reduced equivalent circulating density (ECD), shorter slurry thickening times, improved compressive strength development and reduced downhole pressures, which works as an advantage for not fracturing the formation and puts less load on the casing (Hernández and Bour, 2010). A major drawback of this method is that fluid placement is largely uncontrolled and the shoe is never cemented (Nelson and Guillot, 2006).

Inner string is recommended for cementing the conductor and surface casings owing to the short length of the casing strings which means that less time will be taken to run the cementing string to and from the well. The single stage method will be used for cementing the anchor and production casing strings. High temperatures are expected deeper in the well which dictates that less time should be taken after landing the casing string before cementing takes place. Cement backfilling through the annulus will be done immediately after displacing the cement through the casing shoe for cases where cement returns are not received on the surface.

5. DESIGN CALCULATIONS

Design calculations were done after establishing the minimum depths for the different casing strings in order to determine the safe casing grade, weights and diameter suitable for a well. For well OW-49, the casing grade and diameters are already known since the casing program is the regular type. It comprises of a 20″ surface casing, 13⅜″ anchor casing, 9⅝″ production casing and 7″ slotted liners and the grade chosen is K55 for all the casing strings.

The calculation of the casing strength against burst pressure, axial tensile/compressive force and collapse pressure is critical because it greatly influences the casing grade selection for the well. The mechanical properties of the casing strings were taken from the drilling data handbook (Gabolde and Nguyen 2006). Based on the calculations done, a suitable casing strings grade and weights that possess a considerable margin of strength will be selected for the 4500 m deep well. The design calculations consider that the well is full of steam from bottom to the surface which represents the worst case scenario.

5.1 Design calculations equations from the African Union Standard

Casing stresses were calculated using the following equations as stipulated in the African Union 2016 code of practice for geothermal drilling (AUS, 2016). The code provides a guideline on the calculation of loads that may be encountered by the casing strings, as well as the safety margins needed for an acceptable design. The definition of equation parameters is described in the Nomenclature that is given at the end.

5.1.1 Axial loading before and during cementing

$$F_{hookload} = F_{csg\ air\ wt} + F_{csg\ contents} - F_{displaced\ fluids} \tag{3}$$

where

$$F_{csg\ air\ wt} = L_Z \times W_p \times g \times 10^{-3} \tag{4}$$

$$F_{csg\ contents} = \sum \rho_{if} \times L_{if} \times \frac{\pi d^2}{4} \times g \times 10^{-6} \tag{5}$$

$$F_{displaced\ fluids} = \sum \rho_{ef} \times L_{ef} \times \frac{\pi D^2}{4} \times g \times 10^{-6} \tag{6}$$

5.1.2 Axial loading after cementing

An assessment of axial forces imposed after cementing near the top and at the shoe of the casing string is necessary. The calculation of the resultant net force is a combination of the static force present in the casing at the time cement is setting and each of the casing loadings. For a case where the stress calculated is exceeded, a plastic/strain based design is required.

a. Change in axial force (with tension as positive) due to temperature rise in situations of partial longitudinal and lateral constraint is given by:

$$F_c = E \times a(T_1{}_-T_2) \times A_p \times 10^{-3} \tag{7}$$

The resultant force is:

$$F_r = F_p + F_c \tag{8}$$

b. Change in axial force due to temperature reduction when cool fluid is circulated from the surface during drilling, testing or reinjection:

$$F_t = E \times a(T_1{}_-T_3) \times A_p \times 10^{-3} \tag{9}$$

The resultant force at every depth except close to the wellhead is:

$$F_r = F_p + F_t \tag{10}$$

5.1.3 Tension force occurring at the top of any string that anchors a wellhead against the lifting force by the fluid in the well

$$F_w = \frac{\pi}{4} \times P_w \times d^2 \times 10^{-3} - F_m \tag{11}$$

$$Design\ factor = \frac{minimum\ tensile\ strength}{maximum\ tensile\ load} \geq 1.8 \tag{12}$$

5.1.4 Maximum differential internal pressure during cementing near the shoe or stage cementing ports

$$\Delta P_{internal} = \left[L_z\rho_c - L_f\rho_f\right] \times g \times 10^{-3} \tag{13}$$

$$Design\ factor = \frac{internal\ yield\ pressure}{differential\ internal\ pressure} \geq 1.5 \tag{14}$$

5.1.5 Maximum differential internal pressure after cementing at the surface

Two cases are considered:

i. With steam at the wellhead, the design factor is:

$$Design\ factor = \frac{internal\ yield\ pressure \times Ri}{wellhead\ pressure} \geq 1.8 \tag{15}$$

ii. With cold gas at the wellhead when the stress corrosion tensile limit of the steel should be used to determine the appropriate yield strength

5.1.6 Biaxial stress conditions for a case where a wellhead is fixed to the casing being considered

The combined effects of the axial and circumferential tensions shall be calculated by:

$$f_t = \frac{\sqrt{5}}{2} \times \left(\frac{p_w \times d}{D - d}\right) \tag{16}$$

$$Design\ factor = \frac{steel\ yield\ strength}{maximum\ tensile\ stress} \geq 1.5 \tag{17}$$

5.1.7 Hoop stressing (collapse) during casing cementing operations

$$\Delta P_{external} = \left[L_z \rho_c - L_z \rho_f\right] \times g \times 10^{-3} \tag{18}$$

$$Design\ factor = \frac{pipe\ collapse\ pressure}{differential\ external\ pressure} \geq 1.2 \tag{19}$$

5.1.8 Hoop stressing (collapse) during operations

Maximum external differential pressure occurs near the casing shoe when the annulus is at formation pressure ($P_z = P_f$) and the internal pressure is controlled by well drawdown and therefore:

$$Design\ factor = \frac{pipe\ collapse\ pressure}{differential\ external\ pressure} \geq 1.2 \tag{20}$$

5.2 Design calculations equations from ISO/TR 10400:2007

Although ISO/TR 10400:2007 (2007) is not a design code, it provides equations and templates for calculating properties of tubulars intended for use in downhole applications. The equations were used to calculate the casing strength and specifications. The definitions are given in the Nomenclature.

5.2.1 Triaxial yield of a pipe body

Three equally applicable equations are used to calculate the yield strength of a pipe body subjected to internal pressure:

a. Capped end conditions (axial, radial and hoop stress):

$$P_{iYLc} = \frac{f_{ymn}}{\left(\frac{(3D^4 + d_{wall}^4)}{(D^2 - d_{wall}^2)} + \frac{d^2}{(D^2 - d^2)^2} - \frac{2d^2 d_{wall}^2}{(D^2 - d^2)(D^2 - d_{wall}^2)}\right)^{1/2}} \tag{21}$$

b. Zero axial load (radial and hoop stress):

$$P_{iYLo} = f_{ymn}(D^2 - d_{wall}^2)/(3D^4 + d_{wall}^4)^{1/2} \tag{22}$$

c. Historical, one-dimensional yield pressure:

$$P_{iYAPI} = \left[2f_{ymn}(k_{wall}t)/D\right] \tag{23}$$

5.2.2 External pressure resistance

Collapse strength is primarily a function of the yield strength of the material and its slenderness ratio, or the D/t ratio. There are four collapse regimes that are determined on the basis mentioned above (Economides et al., 1998):

Yield strength collapse: This is based on the yield at the inner wall of the casing/pipe where for K55 material D/t ≤ 14.81.

Plastic collapse: Collapse in this regime is based on empirical data obtained from tests done on a seamless casing of K-55, N-80 and P-110 and is applicable where the slenderness ratio ranges from 14.81 to 25.01 for K55.

Transition collapse: This type of collapse lies between the plastic and elastic regimes and is applicable where D/t ranges from 25.01 to 37.21 for K55.

Elastic collapse: This collapse is based on theoretical instability failure and is independent of the yield strength of a material. It is applicable to a thin wall pipe whose D/t ratio ≥ 37.21 for K55.

In summary, yield strength collapse or plastic collapse will be dominant for relatively thicker casings while transition or elastic collapse will be dominant for relatively thinner casings. Table 1 below describes the D/t ratio for the selected K55 casing grade.

TABLE 1: D/t ratio ranges for K55

Casing grade	D/t range	Applied equation
K55	≤ 14.81	Yield strength collapse
	14.81 ≤ 25.01	Plastic collapse
	25.01 ≤ 37.21	Transition collapse
	≥ 37.21	Elastic collapse

The applied equations are as follows:

a. Yield strength collapse:

$$P_{Yp} = 2f_{ymn}\left[\frac{(D/t)-1}{(D/t)^2}\right] \tag{24}$$

b. Plastic collapse:

$$P_p = f_{ymn}\left[\frac{A_c}{D/t} - B_c\right] - C_c \tag{25}$$

c. Transition collapse:

$$P_T = f_{ymn}\left[\frac{F_c}{D/t} - G_c\right] \tag{26}$$

d. Elastic collapse:

$$P_E = \frac{46.95 \times 10^6}{[D/t(D/t-1)^2]} \tag{27}$$

6. RESULTS

6.1 Design calculation results for the revised well design of OW-49

The revised design calculation results according to the new guidelines in the African Union standard for OW-49 are presented below in Tables 2-11.

6.1.1 Collapse and burst pressures during cementing

Collapse pressure calculations were done by considering the annulus to be filled with 1.7 kg/l of cement slurry and with water of 0.988 kg/l at 50°C inside the casing. Similarly, the burst pressure was calculated by considering the annulus to be filled with water 0.988 kg/l at 50°C and 1.7 kg/l of cement slurry. Results on the collapse and burst pressures and design factors for the different casing strings are tabulated in Tables 2 and 3.

TABLE 2: Casing selection according to collapse resistance against external cement pressure

Casing grade	**Casing weight (lb/ft)**	**Length (m)**	**Net external pressure, $\Delta P_{external}$ (MPa)**	**Collapse resistance ISO/TR 10400 (MPa)**	**Calculated design factor**	**Minimum design factor**
Production casing (9⅝″)- **K55**	47.0	1500	10.48	26.82	2.56	1.20
Anchor casing (13⅜″)- **K55**	54.5	800	5.59	7.88	1.40	1.20
Surface casing (20″)- **K55**	94.0	400	2.79	3.60	1.29	1.20
Conductor pipe (30″)- **X52**	157.8	100	0.70	1.50	2.15	1.20

TABLE 3: Casing selection according to the burst resistance against the internal cement pressure

Casing grade	**Casing weight (lb/ft)**	**Length (m)**	**Net internal pressure, $\Delta P_{internal}$ (MPa)**	**Internal yield pressure ISO/TR 10400 (MPa)**	**Calculated design factor**	**Minimum design factor**
Production casing (9⅝″)- **K55**	47.0	1500	10.48	32.50	3.10	1.50
Anchor casing (13⅜″)- **K55**	54.5	800	5.59	18.90	3.38	1.50
Surface casing (20″)- **K55**	94.0	400	2.79	14.50	5.19	1.50
Conductor pipe(30″)- **X52**	157.8	100	0.70	6.10	8.73	1.50

6.1.2 Axial loading before and during cementing

Axial forces develop and act on the casing string during the running process and before the cementing process commences. Table 4 shows the results on axial forces on casings before and during cementing.

TABLE 4: Axial forces on casings before and during cementing

Casing grade K55	**Casing weight (lb/ft)**	**Length (m)**	$F_{csg\ air\ wt}$ (kN)	$F_{csg\ contents}$ (kN)	$F_{displaced\ fluids}$ **(kN)**	$F_{hookload}$, F_p **(kN)**	**Min.tensile strength (kN)**	**Calculated design factor**	**Minimum design factor**
Production casing (9⅝″)	47.0	1500	1029.22	554.89	682.25	901.85	3319.93	3.68	1.8
Anchor casing (13⅜″)	54.5	800	636.51	624.84	702.39	558.96	3794.55	6.79	1.8
Surface casing (20″)	94.0	400	548.92	717.95	785.39	481.48	6587.75	13.67	1.8

6.1.3 Axial loading after cementing

The change in axial force after cementing may be positive or negative depending on the temperature changes in the well.

a) Change in axial force due to temperature rise:

Axial load may be developed after cementing has been done when the temperature rises in the well. It is assumed that the casing strings for the production, anchor and surface casings were set at a temperature of 75, 50 and 30°C, respectively. The temperature in the well rose to 120°C resulting in temperature changes of 45, 70 and 90°C for the production, anchor and surface casings. Results tabulated in Table 5 indicate a compressive axial force as denoted by the negative values.

TABLE 5: Axial force due to rise in temperature

Casing grade K55	**Casing weight (lb/ft)**	**Compressive force, F_c (kN)**	**Resultant force, F_r (kN)**	**Min. yield strength (kN)**
Production casing (9⅝″)	47.0	-1075.67	-1203.04	3319.93
Anchor casing (13⅜″)	54.5	-1912.72	-1990.26	3794.55
Surface casing (20″)	94.0	-4266.83	-4334.27	6587.75

b) Change in axial force due to temperature reduction when cool fluid is circulated from the surface to the well:

A cold fluid of 25°C is assumed to be introduced into the well through the casing strings of the production, anchor and surface casings that were initially set at a temperature of 75, 50 and 30°C, respectively. Consequently there was a temperature reduction of 50, 25 and 5°C for the production, anchor and surface casings. Table 6 shows the results.

TABLE 6: Tension force due to circulation of cold fluid

Casing grade K55	**Casing weight (lb/ft)**	**Tension force, F_T (kN)**	**Resultant force, F_r (kN)**	**Minimum yield strength (kN)**
Production casing (9⅝″)	47.0	1195.19	1067.83	3319.93
Anchor casing (13⅜″)	54.5	683.11	605.57	3794.55
Surface casing (20″)	94.0	237.05	169.61	6587.75

6.1.4 Tension force occurring at the top of any string that anchors a wellhead against the lifting force by the fluid in the well

The lifting force by the fluid in the well bore may develop tension at the top of the anchor casing supporting the wellhead. Table 7 shows the resulting, calculated tension force. The well is assumed to be full of steam with a maximum wellhead pressure of 16.23 MPa and capped with an ANSI class 1500 TIX master valve weighing approximately 2 tonnes.

TABLE 7: Tension force on the anchor casing due to lifting force by the fluid

Casing grade K55	**Casing weight (lb/ft)**	**Tension force at top, F_w (kN)**	**Min. Tensile strength (kN)**	**Calculated design factor**	**Minimum design factor**
Anchor casing (13⅜″)	68	1246.98	8219.20	6.59	1.80

6.1.5 Design factor for the thermal expansion of the anchor casing into the wellhead

Table 8 shows the design factor calculation results for the determination of the best anchor casing that can withstand stresses introduced during production. It is expected that the production casing may rise into the wellhead during the production phase of the well.

TABLE 8: Design factor for anchor casing thermal expansion into wellhead

Casing grade K55	**Casing weight (lb/ft)**	**Anchor casing tensile strength (kN)**	**Rising casing compressive strength (kN)**	**Calculated design factor**	**Minimum design factor**	**Remarks**
Anchor casing (13⅜″)	54.5	6554.23	5734.42	1.14	1.4	
	61.0	7390.94	5734.42	1.29	1.4	
	68.0	8219.20	5734.42	1.43	1.4	**Sufficient**

6.1.6 Maximum differential burst pressure at the surface after cementing

Calculation of the design factor of the anchor casing selected in Table 8 was done and comparison made against the required minimum design factor to establish its suitability. The results are seen in Table 9.

TABLE 9: Design factor for maximum differential burst pressure at surface after cementing

Casing grade	Casing weight (lb/ft)	Well head pressure (MPa)	Well head temp. (°C)	Temp. reduction factor	Reduced internal yield strength (MPa)	Calculated design factor	Minimum design factor	Remarks
Anchor casing (13⅜″)-**K55**	54.5 72.0	16.23 16.23	348.5 348.5	0.8 0.8	15.12 20.40	0.93 1.26	1.8 1.8	Insufficient
Anchor casing (13⅜″)-**L80**	72.0	16.23	348.5	0.8	31.76	1.96	1.8	Sufficient

6.1.7 Biaxial stress conditions for a case where a wellhead is fixed to the casing being considered

Two joints of the anchor casing that interact with the wellhead and the maximum expected wellhead pressure of 16.23 MPa were considered in the calculation. The results are tabulated in Table 10.

TABLE 10: Biaxial stress on anchor casing

Casing grade L80	Casing weight (lb/ft)	Biaxial stress, F_t (MPa)	Yield strength (MPa)	Calculated design factor	Minimum design factor
Anchor casing (13⅜″)	72	218.03	552.00	2.53	1.5

6.1.8 Hoop stressing (collapse) during production

Maximum external differential pressure occurs near the casing shoe when the well is considered to be full of steam from bottom to the surface during production. The results are tabulated in Table 11.

TABLE 11: Collapse during production

Casing grade K55	Casing weight (lb/ft)	Differential external pressure $\Delta P_{external}$ (MPa)	Production casing collapse pressure (MPa)	Calculated design factor	Minimum design factor
Production casing (9⅝″)	47	9.28	21.46	2.31	1.20

6.2 Selection of the casing grade and weight for the 4500 m deep well

Calculation on the collapse and burst loads and design factors were done in order to determine the appropriate weights and grades for the conductor pipe, and the surface, anchor and production casings for the well. The results are tabulated in Tables 12-20.

6.2.1 Collapse and burst pressures during cementing

Collapse pressure calculations were done by considering the annulus to be filled with 1.7 kg/l of cement slurry and with water of 0.988 kg/l at 50°C inside the casing. Similarly the burst pressure was calculated by considering the annulus to be filled with water 0.988 kg/l at 50°C and 1.7 kg/l of cement slurry in the annulus. Results on the collapse and burst pressures and design factors for the different casing strings are tabulated in Tables 12 and 13.

TABLE 12: Casing selection according to collapse resistance against external cement pressure

Casing grade	Casing weight (lb/ft)	Length (m)	Net external pressure, $\Delta P_{external}$ (MPa)	Collapse resistance ISO/TR 10400 (MPa)	Calculated design factor	Minimum design factor
Production casing (9⅝″) - **K55**	47.0	1700	11.87	26.8	2.26	1.20
Anchor casing (13⅜″) - **K55**	54.5	900	6.29	7.80	1.24	1.20
Surface casing (20″) - **K55**	106.5	480	3.35	5.30	1.58	1.20
Conductor pipe (30″) - **X52**	157.8	100	0.70	1.50	2.15	1.20

TABLE 13: Casing selection according to the burst resistance against the internal cement pressure

Casing grade	Casing weight (lb/ft)	Length (m)	Net internal pressure, $\Delta P_{internal}$ (MPa)	Internal yield pressure ISO/TR 10400 (MPa)	Calculated design factor	Minimum design factor
Production casing (9⅝″) - **K55**	47.0	1700	11.87	32.50	2.74	1.50
Anchor casing (13⅜″) - **K55**	54.5	900	6.29	18.90	3.01	1.50
Surface casing (20″) - **K55**	106.5	480	3.35	16.60	4.95	1.50
Conductor pipe(30″) - **X52**	157.8	100	0.70	6.10	8.73	1.50

6.2.2 Axial loading before and during cementing

Table 14 shows the results on the axial forces on casings before and during cementing.

TABLE 14: Axial forces on casings before and during cementing

Casing grade	Casing weight (lb/ft)	Length (m)	$F_{csg\ air\ wt}$ (kN)	$F_{csg\ contents}$ (kN)	$F_{displaced\ fluids}$ (kN)	$F_{hookload}$, F_p (kN)	Min. Tensile strength (kN)	Calcul. design factor	Min. design factor
Production casing (9⅝″) - **K55**	47.0	1700	1166.45	628.87	773.22	1022.10	3318.52	3.25	1.8
Anchor casing (13⅜″) - **K55**	54.5	900	716.07	702.95	790.19	628.84	3793.41	6.03	1.8
Surface casing (20″) - **K55**	106.5	480	746.29	850.57	942.46	654.40	7489.80	11.45	1.8
Conductor casing (30″) - **X52**	157.8	100	230.37	405.79	441.78	194.38	10734.10	55.22	1.8

6.2.3 Axial loading after cementing

a) Change in axial force due to temperature rise:

Axial load may be developed after cementing has been done when the temperature rises in the well. It is assumed that the casing strings for production, anchor, surface and conductor were set at a temperature of 85, 65, 45, and 30°C, respectively. The temperature in the well rose to 125°C resulting into temperature changes of 40, 60, 80, and 95°C for the production, anchor, surface and conductor casings. Results tabulated in Table 15 indicate a compressive axial force as denoted by the negative values.

TABLE 15: Axial force due to rise in temperature

Casing grade	Casing weight (lb/ft)	Compressive force, F_c (kN)	Resultant force, F_r (kN)	Min. yield strength (kN)
Production casing (9⅝″)- **K55**	47.0	-956.16	-1100.50	3318.52
Anchor casing (13⅜″)- **K55**	54.5	-1639.47	-1726.71	3793.41
Surface casing (20″)- **K55**	106.5	-4316.02	-4407.91	7489.80
Conductor casing (30″)- **X52**	157.8	-9654.82	-9690.81	10734.10

b) Change in axial force due to temperature reduction when cool fluid is circulated from the surface to the well:

A cold fluid of 25°C is assumed to be introduced into well and the casing strings for production, anchor surface and conductor casings were initially set at a temperature of 85, 65, 45, and 30°C, respectively. Consequently, there was a temperature reduction of 60, 40, 20, and 5°C for the production, anchor, surface and conductor casings. Table 16 shows the results.

TABLE 16: Tension force due to circulation of cold fluid

Casing grade	Casing weight (lb/ft)	Tension force, F_T (kN)	Resultant force, F_r (kN)	Minimum yield strength (kN)
Production casing (9⅝″)- **K55**	47.0	1642.91	1498.57	3318.52
Anchor casing (13⅜″)- **K55**	54.5	1092.98	1005.74	3793.41
Surface casing (20″)- **K55**	106.5	1079.01	987.12	7489.80
Conductor casing (30″)- **X52**	157.8	508.15	472.16	10734.10

6.2.4 Tension force occurring at the top of any string that anchors a wellhead against the lifting force by the fluid in the well

The lifting force by the fluid in the well bore may develop tension at the top of the anchor casing supporting the wellhead. Table 17 shows the resulting, calculated tension force. The well is assumed to be full of steam with a maximum wellhead pressure of 19.09 MPa and capped with a master valve weighing approximately 2 tonnes.

TABLE 17: Tension force on anchor casing due to lifting force by the fluid

Casing grade T95	Casing weight (lb/ft)	Tension force at top, F_w (kN)	Min. Tensile strength (kN)	Calculated design factor	Minimum design factor
Anchor casing (13⅜″)	77	1437.28	9364.39	6.20	1.80

6.2.5 Design factor for the thermal expansion of the anchor casing into the wellhead

Table 18 shows design factor calculation results for the determination of the best anchor casing that can withstand stresses introduced during production.

TABLE 18: Design factor for anchor casing thermal expansion into wellhead

Casing grade T95	Casing weight (lb/ft)	Anchor casing tensile strength (kN)	Rising casing compressive strength (kN)	Calculated design factor	Minimum design factor
Anchor casing (13⅜″)	77	9364.39	5437.42	1.63	1.4

6.2.6 Maximum differential burst pressure at the surface after cementing

Calculation of the design factor of the anchor casing selected in Table 18 was done and comparison made against the required minimum design factor to establish its suitability. The results are tabulated in Table 19.

TABLE 19: Design factor for maximum differential burst pressure at surface after cementing

Casing Grade T95	Casing weight (lb/ft)	Well head pressure (MPa)	Well head temp. (°C)	Temp. Reduction factor	Internal yield strength (MPa)	Calculated design factor	Minimum design factor
Anchor casing (13⅜″)	77	19.09	361.8	0.8	37.68	1.97	1.8

6.2.7 Biaxial stress conditions for a case where a wellhead is fixed to the casing being considered

Two joints of the anchor casing that interact with the wellhead and the maximum expected wellhead pressure of 19.09 MPa were considered in the calculation. The results are tabulated in Table 20.

TABLE 20: Biaxial stress on anchor casing

Casing grade T95	Casing weight (lb/ft)	Biaxial stress, F_t (MPa)	Yield strength (MPa)	Calculated design factor	Minimum design factor
Anchor casing (13⅜″)	77	238.52	655.00	2.75	1.50

6.2.8 Hoop stressing (collapse) during production

Maximum external differential pressure occurs near the casing shoe when the well is considered to be full of steam from bottom to the surface during production. The results are tabulated in Table 21.

TABLE 21: Collapse during production

Casing grade K55	Casing weight (lb/ft)	Differential external pressure $\Delta P_{external}$ (MPa)	Production casing collapse pressure (MPa)	Calculated design factor	Minimum design factor
Production casing (9⅝″)	47	10.63	26.80	2.52	1.2

6.3 Cementing calculations for the 4500 m deep well

Table 22 shows the results of the cement calculations done for each casing string and the total cement requirement for the well.

TABLE 22: Cement calculations for 4500 m deep well

Casing size	Volume (m^3)
Conductor casing, 30″ 157.8 lb/ft X52	
Slurry volume between 30″casing and 36″ drilled hole	17.48
Slurry volume in the shoe track	5.03
Slurry volume in the rat hole	0.66
Slurry volume for open hole excess (100%)	18.13
Total volume of cement with open hole excess required for conductor casing	**41.30**
Surface casing, 20″ 106.5 lb/ft K55	
Slurry volume between 20″casing and 26″ drilled hole	51.32
Slurry volume between 30″and 20″casing	18.83
Slurry volume in the shoe track	2.16
Slurry volume in the rat hole	0.69
Slurry volume for open hole excess (100%)	52.01
Total volume of cement with open hole excess required for surface casing	**125.00**
Anchor casing, 13⅜″ 54.5 lb/ft K55	
Slurry volume between 13⅜″casing and 17½″ drilled hole	26.32
Slurry volume between 20″ and 13⅜″ casing	43.00
Slurry volume in the shoe track	0.95
Slurry volume in the rat hole	0.31
Slurry volume for open hole excess (100%)	26.63
Total volume of cement with open hole excess required for anchor casing	**97.22**

Production casing, 9⅝″ 47 lb/ft K55	
Slurry volume between 9⅝″ casing and 12¼″ drilled hole	17.11
Slurry volume between 13⅜″ and 9⅝″ casing	29.86
Slurry volume in the shoe track	0.44
Slurry volume in the rat hole	0.15
Slurry volume for open hole excess (100%)	17.27
Total volume of cement with open hole excess required for production casing	**64.83**
Total volume of cement required for the well	***328.35***

6.4 Wellhead selection

Design considerations for the well head assume that the well is full of saturated steam from bottom to the surface of the wellhead, which represents the worst case scenario for well OW-49 and the 4500 m deep well. Figure 6 indicates that the expected pressure for well OW-49 is 16.23 MPa at 348.5°C. Similarly, Figure 7 shows that the expected pressure for the 4500 m deep well is 19.09 MPa at 361.8°C. Consequently, the wellhead selected for each well should withstand the pressure and temperature exposure mentioned above. Figure 8 shows that the most suitable wellhead for OW-49 and the 4500 m deep well is the ANSI Class 1500.

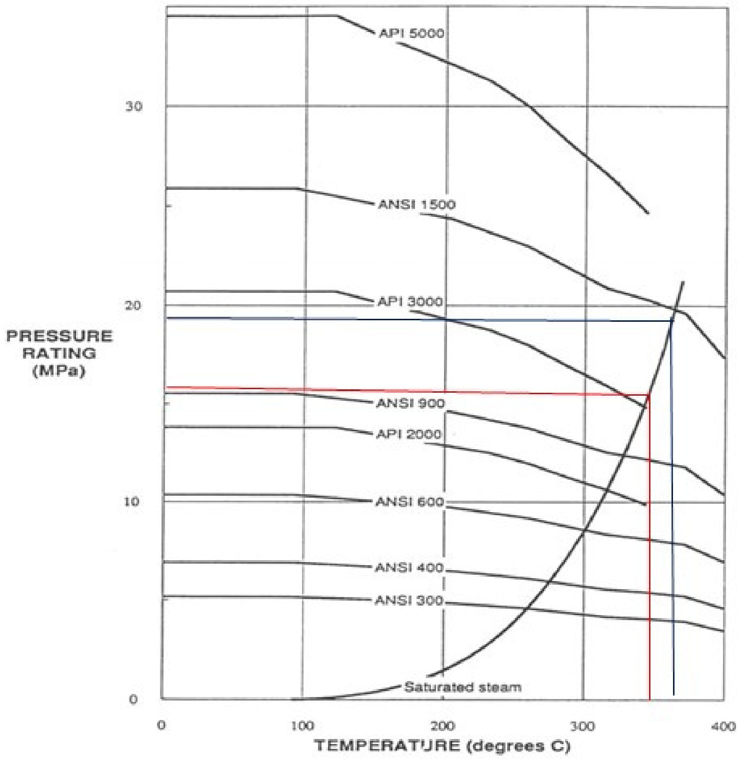

FIGURE 8: Wellhead working pressure de-rating for flanges (New Zealand Standard, 2015)

7. DISCUSSION

7.1 Well design casing and wellhead data

Design calculation results greatly influenced the decision on the casing and wellhead selection for the wells. Table 23 gives information on hole sizes, casing and wellhead selection for well OW-49 and the 4500 m deep well.

TABLE 23: Hole sizes, casing and wellhead details for OW-49 and 4500 m deep well

Description	OW-49	Revised design (OW-49)	Deep well (4500 m)
Surface hole			
Hole size (inches)	-	36	36
Setting depth(m)	-	100	100
Casing size (inches)	-	30	30
Casing grade	-	X52	X52
Casing weight(lb/ft)	-	157.8	157.8
Intermediate hole			
Hole size (inches)	26	26	26
Setting depth(m)	55	400	480
Casing size (inches)	20	20	20
Casing grade	K55	K55	K55
Casing weight(lb/ft)	94	94	106.5
Anchor hole			
Hole size (inches)	17½	17½	17½
Setting depth(m)	404	800	900
Casing size (inches)	13⅜	13⅜	13⅜
Casing grade	K55	K55	K55
Casing weight(lb/ft)	54.5	54.5	54.5
Top joints supporting wellhead			
Casing size (inches)	13⅜	13⅜	13⅜
Casing grade	K55	L80	T95
Casing weight(lb/ft)	68	77	77
Production hole			
Hole size (inches)	12¼	12¼	12¼
Setting depth(m)	1202	1500	1700
Casing size (inches)	9⅝	9⅝	9⅝
Casing grade	K55	K55	K55
Casing weight(lb/ft)	47	47	47
Main hole			
Hole size (inches)	8½	8½	8½
Setting depth(m)	3650	3650	4500
Casing size (inches)	7	7	7
Casing grade	K55	K55	K55
Casing weight(lb/ft)	26	26	26
Wellhead			
Wellhead (ANSI class)	900	1500	1500

7.2 Minimum casing depths

The determination of the minimum casing depths for well OW-49 using the African Union code 2016 results in deeper casings than were selected in the original design. By using the revised standard, the 20″ surface casing, 13⅜″ intermediate casing and 9⅝″ production casing should be set at 400 m, 800 m and 1500 m respectively, as opposed to the current setting of 55 m, 404 m and 1202 m. The reason for this change in casing depths is attributed to the fact that the revised code considers the fracture pressure gradient as the maximum boundary, as opposed to the NZS 2403.1991 which considers the overburden of the formation. Based on the setting depth of the surface casing, it was established that a conductor pipe running to approximately 100 m should be incorporated in the design to enable the safe drilling of the surface hole. The conductor pipe would provide protection against formation collapse of the top section of the well bore. These findings also mean that a large blow out preventer, 29½″, 500 psi rated BOP, should be introduced for well control while drilling the surface hole.

7.3 Collapse and burst pressures during cementing

Calculations on casing strength against collapse and burst pressures were done for the 20″, 94 lb/ft K55 surface casing, 13⅜″, 54.5 lb/ft K55 intermediate casing and 9⅝″, 47 lb/ft K55 production casing. This was done to evaluate whether the current casing set up for well OW-49 is strong enough to withstand the pressures exerted during cementing. This was achieved by comparing the results obtained for the calculated design factor against the minimum design factor stipulated in the African Union code.

Results for collapse pressure for the surface casing at 400 m was 2.79 MPa with a design factor of 1.29. The minimum design factor from the code is 1.2 which meant that the design was adequate. It was however noted that the design would become inadequate in case a cement slurry higher than 1.7 kg/l would be used. This would dictate the selection of another casing with more weight, most preferably the 106.5 lb/ft casing. Burst pressure calculation for the surface casing indicated a burst pressure of 2.79 MPa with a design factor of 5.19 against a design factor of 1.5 from the code. This result revealed that the design was adequate.

Collapse pressure for the intermediate casing at 800 m was 5.59 MPa at the casing shoe with a design factor of 1.41. The minimum design factor from the code is 1.2 which meant that the design was adequate. Burst pressure calculation for the intermediate casing indicated a burst pressure of 5.59 MPa with a design factor of 3.38 against a design factor of 1.5 from the code which indicated that the design was adequate.

Collapse pressure for the production casing at 1500 m was 10.48 MPa at the casing shoe with a design factor of 2.56. The minimum design factor from the code is 1.2 which meant that the design was sufficient. Burst pressure calculation for the intermediate casing indicated a burst pressure of 10.48 MPa with a design factor of 3.1 against a design factor of 1.5 from the code which established that the design was sufficient.

Calculations on collapse and burst pressures were also done to determine the best conductor casing for well OW-49. A 30″, 157.8 lb/ft X52 conductor pipe was selected and the results for collapse pressure at 100 m was 0.7 MPa with a design factor of 2.15. The minimum design factor from the code is 1.2 which meant that the design was sufficient. Burst pressure was found to be 0.7 MPa at the shoe with a design factor of 6.1 against a design factor of 1.5 from the code which established that the design was sufficient.

Similarly, calculations on collapse and burst pressures were done to determine the best grades and weights for the conductor casing, surface casing, anchor casing and the production casing for the 4500 m deep well. A 30″, 157.8 lb/ft X52 conductor pipe was selected as the conductor casing and results for collapse pressure at 100 m was 0.7 MPa with a design factor of 2.15 against a design factor of 1.2. Burst pressure results indicated a pressure of 0.7 MPa at the shoe with a design factor of 6.1 against a design factor of 1.5 which meant that the selection was satisfactory.

A *20", 106.5 lb/ft K55 casing* was selected as the surface casing. The results for the collapse pressure for the surface casing at 480 m was 3.35 MPa with a design factor of 1.58. The minimum design factor from the code is 1.2 which meant that the selection was satisfactory.

A *13⅜", 54.5 lb/ft K55 casing* was selected as the anchor casing. The results for the collapse pressure for the anchor casing at 900 m was 6.29 MPa with a design factor of 1.24. The minimum design factor from the code is 1.2 which meant that the selection was satisfactory.

A *9⅝", 47 lb/ft K55 casing* was selected as the production casing. The collapse pressure calculation at 1700 m indicated a pressure of 11.87 MPa with a design factor of 2.26. The code stipulates a minimum design factor of 1.2 which established that the selection was satisfactory.

7.4 Axial forces on casings before and during cementing

The calculated axial load for the surface casing was 481.48 kN and the design factor 13.67. A comparison made between the calculated design factor against the code's stipulated minimum design factor of 1.8 showed that the design was satisfactory.

Results indicated an axial force of 558.96 kN and a design factor of 6.79 for the anchor casing. The design factor was above the minimum design factor of 1.8 meaning that the design was adequate. For the production casing, the results gave an axial force of 901.85 kN and a design factor of 3.68 which also demonstrated that the design was sufficient.

The same calculations were done for the casings selected for the 4500 m deep well. Results obtained for the conductor pipe indicated an axial force of 194.38 kN with a design factor of 55.22. The surface casing showed an axial force of 654.40 kN and a design factor of 11.45 against a minimum design factor of 1.8. This indicated that the selected surface casing was adequate. The computed axial forces for the anchor casing was 628.84 kN and the design factor was 6.03. Comparison made between the calculated design factor and the minimum design factor showed that the casing selected met the minimum casing design requirements. Similarly, calculation results for production casing gave an axial force of 1022.10 kN and a design factor of 3.25 which also met the minimum design factor of 1.8.

7.5 Axial loading after cementing

Axial loads exerted on the casings due to temperature variations in the well were calculated and considered as the static forces which were then used to determine the resultant forces on the casing strings.

The calculated axial load due to temperature rise for the surface casing was 4334.27 kN against a minimum yield strength of 6587.75 kN. Computation showed a compressive force of 1990.26 kN against a minimum tensile strength of 3794.55 kN for the anchor casing. Results for the production casing gave an axial force of 1203.04 kN against a minimum tensile strength of 3319.93 kN.

The calculated tensile force due to circulation of cold fluid for the surface casing was 169.61 kN against a minimum yield strength of 6587.75 kN. Computation showed a tensile force of 605.57 kN against a minimum tensile strength of 3794.55 kN for the anchor casing. Results for the production casing gave a tensile force of 1067.83 kN against a minimum tensile strength of 3319.93 kN.

The same calculations were done for the casings selected for the 4500 m deep well. Results obtained for the axial load due to temperature rise for the conductor pipe indicated a force of 9690.81 kN against a minimum tensile force of 10734.10 kN. The surface casing showed an axial force of 4407.91 kN against a minimum tensile force of 7489.80 kN. Computation showed a compressive force of 1726.71 kN against a minimum tensile strength of 3793.41 kN for the anchor casing. Results for the production casing gave an axial force of 1100.50 kN against a minimum tensile strength of 3318.52 kN.

The calculated tensile force due to circulation of cold fluid for the conductor pipe indicated a force of 472.16 kN against a minimum tensile force of 10734.10 kN. The calculated tensile force for the surface casing was 987.12 kN against a minimum yield strength of 7489.80 kN. Computation showed a tensile force of 1005.74 kN against a minimum tensile strength of 3793.41 kN for the anchor casing. Results for the production casing gave a tensile force of 1498.57 kN against a minimum tensile strength of 3318.52 kN.

The results above indicated that all the casings selected for the two wells met the minimum design requirements and were therefore sufficient.

7.6 Tension force on the anchor casing due to lifting force by the fluid

Calculations were also done to determine the tension force developed by the lifting fluid in the well at the top anchor casing. For the case of well OW-49, calculation done for the 13⅜″, 68 lb/ft K55 anchor casing supporting the wellhead indicated a tension force of 1247 kN and a design factor of 6.59. The minimum design factor is 1.8 which means that the design is safe.

The same calculation was done to determine the most suitable grade and weight for the anchor casing that would support the wellhead for the 4500 m deep well. Results obtained for 13⅜″, 77 lb/ft T95 showed a tension force of 1437.28 kN and a design factor of 6.52. The required minimum design factor is 1.8 which confirmed its suitability.

7.7 Design factor for the thermal expansion of the anchor casing into wellhead

Calculation was done to evaluate the strength of the anchor casing for well OW-49 against stresses introduced by the production casing during the production phase of the well. Results showed a design factor of 1.43 for the 68 lb/ft casing against the required stipulated minimum design factor of 1.4. This meant that the casing was satisfactory.

Equally, the same calculation yielded a design factor of 1.63 for the 13⅜″, 77lb/ft T95 selected for the 4500 m deep well.

7.8 Maximum differential burst pressure at surface after cementing

Calculation of the design factor for the anchor casing mentioned in chapter 7.6 was done and a comparison made against the required minimum design factor of 1.8. Results obtained for the 13⅜″, 68lb/ft K55 showed that the casing selected was inadequate in strength and therefore there is a need to change the casing grade and weight to 13⅜″, 72lb/ft L80 with a design factor of 1.96.

Results obtained for the 4500 m deep well, the 13⅜″, 77lb/ft T95 gave a design factor of 1.97 which established that the casing met the required minimum design factor.

7.9 Biaxial stress conditions for a case where a wellhead is fixed to the casing

The biaxial stress calculated for the OW-49 well and the 13⅜″, 72lb/ft L80 casing grade was 218.03 MPa and a design factor of 2.53. Comparison made against the required minimum safety factor of 1.5 showed that the casing selection was appropriate.

Similarly, results obtained for the 4500 m deep well, the 13⅜″, 77lb/ft T95 casing showed a design factor of 2.75 which was satisfactory.

7.10 Hoop stressing during operations

Results showed that the 9⅝″, 47 lb/ft K55 casing was sufficient in terms of strength. A calculated design factor of 2.31 was obtained against the required minimum design factor of 1.2.

Results showed that the 9⅝″, 47 lb/ft K55 casing selected for the deep well was sufficient. A calculated design factor of 2.52 was obtained against the required minimum design factor of 1.2.

8. CONCLUSION

Determination of design premises is a critical aspect of a well design. A good well design for a geothermal well should account for anticipated conditions during drilling and operation of the well which may compromise the safety and eventually its life span. Well design for a deep geothermal well poses a huge challenge due to the anticipated super critical conditions in the well. This calls for the careful selection of casing strings and a wellhead that can withstand high temperatures and pressure exposure without compromising on safety.

Minimum casing depths for all casing strings are set deeper using the African Union code compared to the case of NZS 2403:1991. This is because the revised code considers fracture pressure gradient as the maximum boundary for the determination of minimum casing depths as opposed to the NZS 2403:1991 (NZS, 1991), which considers the overburden of underlying formation. Care should be taken to ensure that the cold part of the reservoir is completely sealed off to avoid the mixing of low enthalpy fluids with high enthalpy fluids that may result in corrosion or scaling on the casing.

The African Union Standard (AUS, 2016) code incorporated the revised New Zealand Standard code, NZS 2403:2015 (NZS, 2015), and therefore the design factors in the two codes are similar. Ngigi (2015) states that some of the minimum design factors have been reduced in the 2015 code when compared to the 1991 code (NZS, 1991). For example, the temperature reduction factor for the yield strength of steel at a temperature of 300°C has been reduced from 0.95 to 0.8. This reduction in the design factor greatly contributed to the change of the two upper joints of the anchor casing for well OW-49 from 13⅝″, 68 lb/ft K55 to 13⅝″, 77 lb/ft L80. Similarly, the 2015 revision acknowledges that conventional design factors for compressive stress due to thermal expansion (that used to be 1.2) are not applicable due to casings reaching yield and have therefore been dropped.

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NOMENCLATURE

A_c	= Empirical constant in the historical API collapse equation
a	= Coefficient of thermal expansion (°C^{-1})
B_c	= Empirical constant in the historical API collapse equation
C_c	= Empirical constant in the historical API collapse equation
D	= Pipe outside diameter (mm)
d	= Pipe inside diameter (mm)
d_{wall}	= Inside diameter based on $K_{wall}t$, $d_{wall}=D-2K_{wall}t$
E	= Modulus of elasticity (MPa)

F_C = Empirical constant in the historical API collapse equation
F_c = Compressive force due to heating (kN)
$F_{csg\ air\ wt}$ = Casing weight in air (kN)
$F_{displaced\ fluids}$ = Weight of fluids displaced by casing (kN)
$F_{hookload}$ = Surface force suspending casing that is subject to gravitational and static hydraulic loads (kN)
F_m = Net downward force applied by the wellhead (kN), due to its own mass and any pipework reactions
F_P = Axial force within casing body at cement set (kN)
F_p = Tensile force at surface from casing weight (kN)
F_r = Resultant axial force within casing body combining the force at cement set and subsequent thermal forces (kN)
F_T = Change in axial force within casing body due to cooling (kN)
F_t = Tensile force due to cooling (kN)
F_w = Lifting force due to wellhead pressure (MPa)
f_t = Maximum tensile stress (MPa)
f_{ymn} = Minimum yield strength (MPa)
G_C = Empirical constant in the historical API collapse equation
G_f = Cement slurry density (for example 1.8 kg/l)
g = Acceleration due to gravity (for example 9.81 m/s^2)
h = Depth below liquid level (m)
K_{wall} = Specified manufacturing tolerance of pipe wall, e.g. tolerance of 12.5%=0.875
L_{ef} = Vertical length of a section of fluid having the same density within the external annulus (m)
L_f = Total vertical length of a fluid column in an annulus/depth below liquid level (m)
L_{if} = Vertical length of a section having the same density within the casing (m)
L_z = Length of liner or depth of casing below any level (m)
P_E = Elastic collapse pressure (MPa)
P_f = Pore pressure (MPa)
P_{frac} = In situ fracture pressure of a formation (MPa)
P_i = Differential internal yield pressure (MPa)
P_{iYAPI} = Internal pressure at yield for a thin tube (MPa)
P_{iYLc} = Internal pressure at yield for a capped-end thick tube (MPa)
P_{iYLo} = Internal pressure at yield for an open-end thick tube (MPa)
P_p = Plastic collapse pressure (MPa)
P_Y = Transition collapse pressure (MPa)
P_{Yp} = Yield strength collapse pressure (MPa)
P_w = Maximum wellhead pressure (MPa)
P_z = External fluid pressure at casing shoe (MPa)
R_i = Temperature reduction factor (ratio)
S_v = Overburden pressure (vertical pressure due to the weight of the overlying formations MPa)
T_1 = Neutral temperature (that is temperature of casing at time of cement set – °C)
T_2 = Maximum expected temperature (°C)
T_3 = Minimum temperature after cooling well (°C)
W_p = Nominal unit weight of casing (kg/m)
$\Delta P_{external}$ = Differential collapse pressure of casing during cementing (MPa)
$\Delta P_{internal}$ = Differential burst pressure of casing during cementing (MPa)
ρ = Density of underlying bedrock (kg/m3)
ρ_c = Cement slurry density (kg/l)
ρ_f = Density of fluid usually water in the well bore or annulus (kg/l)
ρ_{if} = Density of a section of fluids with constant density within a casing (kg/l)
ν = Poisson's ratio
π = 3.142 (that is to 4 significant figures)

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