UNESCO GRÓ GTP
United Nations Educational, Scientific and Cultural Organization · Geothermal Training Programme Under the auspices of UNESCO

GRÓ GTP, Grensásvegur 9,
IS-108 Reykjavík, Iceland

Reports 2021
Number 27

WELL DESIGN FOR THE GALE LE GOMA SITE, ASAL REGION USING THE AFRICAN CODE OF PRACTICE: A CASE STUDY OF WELL GLG-1 AND WELL DESIGN FOR THE UPCOMING WELL P-1

Mohamed Ali Tabet
Djiboutian Office for the Development of Geothermal Energy (ODDEG)
PK20, zone Industriel, Raod national N°1
REPUBLIC OF DJIBOUTI
mohamed.ali@oddeg.dj; *med50@hotmail.co.uk*

ABSTRACT

The intention of this report is to prepare a well design for the upcoming well at Gale le Goma field, located in the Asal region (P-1) by considering experience from well GLG-1, which was drilled in 2016. Existing well lithology data was analysed in order to prepare an updated well design according to the guidelines in the *African Union Code of Practice for Geothermal Drilling*. Asal-3, Asal-6 and GLG-1 are located at the same area and drilled into the same reservoir. Therefore, they have a similar lithological structure. Accordingly, the same lithology will be used to design the upcoming well P-1. The wells encounter highly saline reservoir fluid of 120,000 ppm (120 g/L). The planned depth of GLG-1 was 700 m MD and the resulting minimum depth of the production casing was set at 300 m MD with a 12¼" production section down to 700 m MD. Correspondingly, the surface casing has a minimum setting depth of 60 m MD. The selected casing steel grade was API 5CT of material grade J-55 for the surface casing and the production casing and N-80 for the anchor casing. The casings are selected based on the analysis of the available data and the assessment of expected subsurface conditions from the wellhead down to the well target. These include considerations on geological formations, formation pressures, BHT, and geothermal fluid properties, e.g. H_2S gas presence and salinity. Casing thicknesses and material grades are selected according to calculated design factors (DF) that need to exceed the minimum design factors defined in the *African Union Code of Practice for Geothermal Wells*. The selected casings for the upcoming well in Asal are of API 5CT steel grade K-55 for the surface casing and L-80 for the anchor and productions section since it allows for more control on chemical compositon than K-55. L-80 casing grade is also beneficial for the extreme salinity in the Asal area that may lead to excessive corrosion of the casing in the borehole. The planned depth is 1300 m MD and the resulting minimum setting depth of the production casing is 800 m MD. The surface casing has a minimum setting depth of 250 m MD and the anchor casing will be 450 m MD deep. This paper describes assumptions that define appropriate casing design with emphasis on safe drilling and reduced risk of casing failure in the well. Choosing suitable materials will ensure safe operation and extended life time of the well.

1. INTRODUCTION

Well design is one of the crucial tasks before the drilling phase. Appropriate well design relies on data on formation pressures and temperatures, lithology and intended hole depth as well as other elements that are essential for the final selection of casing weights and grades. Calculated design factors (DF) must exceed minimum design factors required by the *African Union Code of Practice for Geothermal Drilling* (African Union's Regional Geothermal Coordination Unit, 2016). Burst, collapse, and axial loads to the casings during drilling and well operation are considered. H_2S gas presence and salinity are considered separately from the stress design. Scaling challenges are one of the critical issues that need to be taken into consideration when designing a well. A potential solution to minimize scaling is to select a large diameter, e.g. 13-3/8, for the production casing where scaling appears. A well design with a deeper production casing should be considered in order to avoid having the deposition zone inside the liner. Instead, the scaling would occur at a place where a cleaning operation can be successful and controlled by the pressure drop in the well. Seven wells have been drilled in the Asal geothermal area. Asal-1 and 2 were drilled in 1975 (BRGM, 1975), and Asal-3 and Asal-6 were drilled in 1989 (Aquater, 1989). The wells have produced extremely saline fluids due to the reservoir condition with saline water inflow from the lake Asal area (Jalludin, 2009). Combined lithology from Asal-3 and Asal-6 is used here as a reference for designing the new well that is planned to be drilled near those wells, as they encounter the same reservoir and are presumably fed by the same aquifer. The average mass flow rate at Asal-3 has been found to be 40 kg/s at 18 bar with a maximum temperature of 263°C (Virkir-Orkint, 1990). Asal-6 was not stabilized in contrast to Asal-3 well due to the high scaling rates that occurred (Aquater, 1989). The salinity is around 120,000 ppm (120 g/L), which is more than 3 times higher than seawater salinity (Elmi, 2005). The objective of the current study is to prepare an appropriate well design for the first well in the Gale Le Goma field (P-1) by considering drilling problems experienced at previous well GLG-1 in the Asal area and by following requirements of the African Union Code of Practice for safe drilling and well integrity.

2. GEOLOGICAL SETTING OF THE ASAL AREA

The Asal Rift is the most active tectonic structure in the zone of crustal divergence in Afar (Figure 1). The Asal area creates a typical oceanic type rift valley, with a highly settled graben structure displaying axial volcanism. The Asal series are relatively complex in structure because of different periods of active volcanism during the Quaternary, each with very different characteristics depending on the sites of appearance. Generally, the Asal series are composed of porphyritic basalt formations and hyaloclastites. First, 2 wells were drilled in 1975 and 4 other wells drilled between 1982-1989. The existence of a shallow crust-melting zone, significant seismic activity, and the presence of fumaroles and hot springs make it possible to classify this region as a zone with high geothermal potential (Barberi et al.,1980; Sanjuan et al.,1990). The salinity of the water of this region is extremely high, about 3 times the salinity of seawater.

3. STRATIGAPHRY

3.1 Main stratigraphic units

A brief outline of the main stratigraphic units of the area is given below:

Dalha basalt series: This unit consists of a sequence of lava flows, with intercalations of rhyolites, trachytes and detritic deposits. The age ranges between 8.9 and 3.8 Ma (ISERST, 1985).

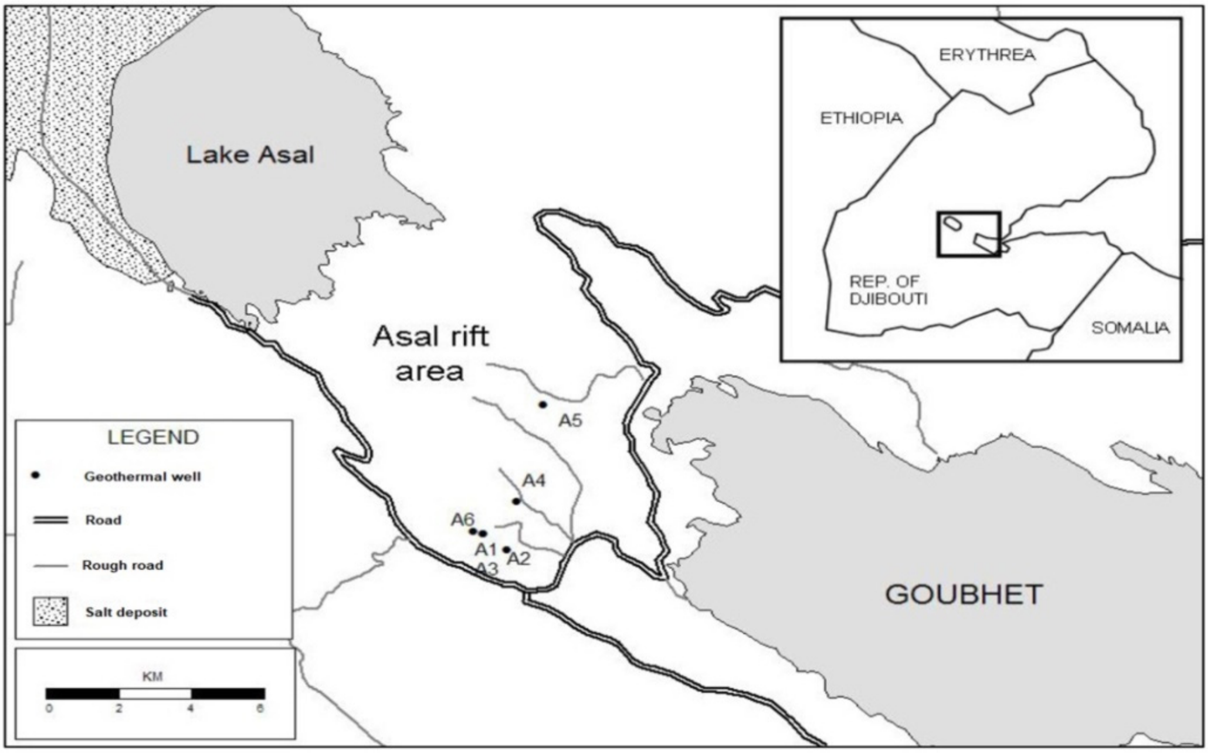


FIGURE 1: Asal geothermal field. Reproduced from Elmi (2005).

Afar stratoid series: The volcanism of the central Afar produced this sequence of basalt- dominated fissural flows, associated with rhyolitic volcanic centres. This unit overlies often uncomfortably the Dalha basalt series. Its products are mainly basaltic, with intercalations of intermediate products such as trachytes and rhyolites. Lacustrine deposits are also common. Pleistocene clays are underlined by an acidic, rhyolitic level. The age ranges between 4 and 1 Ma (Barberi et al., 1980).

Pleistocene clays: Claystone, clay with basalt interlayered.

Asal series: This unit groups the recent basalts and hyaloclastites which were created during the onset of the volcanism of the Asal Rift and outcrop on both sides of the rift. The maximum age of these products is 1.05 Ma (ISERST, 1985).

3.2 General rock descriptions

Basalt is a volcanic rock formed through the rapid cooling of basaltic lava. Flood basalts are created by a series of successive basaltic lava flows. The mineralogy of basalt primarily comprises calcic plagioclase, pyroxene, and feldspar. Olivine can also be an important component. In addition, accessory minerals present in relatively minor amounts include iron oxides and iron-titanium oxides, such as ilmenite and magnetite. Basalt can obtain strong magnetic properties as it cools and paleo-magnetic studies have made extensive use of basalt (Figure 2).

Rhyolite is a volcanic rock of felsic silica-rich composition (typically > 69% SiO_2 – see the TAS classification). It can be slightly glassy, aphanitic or porphyritic. The mineral assemblage is usually quartz, sanidine and plagioclase (in a ratio > 2:1). Biotite and hornblende are common accessory minerals. It is the extrusive equivalent to granite (Figure 3).

FIGURE 2: Representative image of basalt sample (GLG-1 Well Program)

FIGURE 3: Representative image of rhyolite sample (GLG-1 Well Program)

Trachyte is an igneous rock with an aphanitic to porphyritic texture. It is the volcanic equivalent of syenite. The mineral assemblage includes mainly alkali feldspar with minor amounts of plagioclase and quartz. A feldspathoid including nepheline can also be present. Biotite, clinopyroxene, and olivine are not unusual either. Chemically, trachyte consists of 60 to 65% silica content, which is greatly less SiO_2 than in rhyolite and more (Na_2O plus K_2O) than in dacite. These chemical variations are common considering the position of trachyte in the TAS classification, which accounts for the feldspar-wealthy mineralogy of the rock type (Figure 4).

Hyaloclastite is a volcanic rock, formed during volcanic eruptions underwater, under ice or where subaerial flows reach the ocean or other bodies of water. It consists of angular flat fragments sized between a millimetre and a few centimetres. The fragmentation occurs by the force of the volcanic explosion or by thermal shock during rapid cooling. Several minerals are found in hyaloclastite masses. Sideromelane is a basalt glass rapidly quenched in water. It is transparent and pure, lacking the iron oxide crystals dispersed within the more commonly occurring achylyte. Fragments of those glasses are usually surrounded by a yellow waxy layer of palagonite, formed by the reaction of sideromelane with water (Figure 5).

FIGURE 4: Representative image of trachyte sample (GLG-1 Well Program)

FIGURE 5: Representative image of hyaloclastite sample (GLG-1 Well Program)

3.3 Stratigraphy and structure

The stratigraphy of the Gale le Goma area to the depth of the existing wells consists primarily of recent to late Miocene series of volcanic rocks divided into several series. These series are divided on the basis of age with the Asal series being the most recent (less than one million year old) volcanic rocks, the Afar/Stratoid series, containing Pleistocene to Pliocene (1-4 mya) sedimentary and volcanic rocks, and the older (4-9 mya) Dahla series dominated by basaltic lavas (Barberi et al., 1980). Productive intervals in existing wells were identified by lost circulation and tested within the Dalha basalt in A-1, A-3, and A-6 between 1100 m and 1700 m. There were smaller drilling losses down to 2000 m within the Dalha basalt in well A-4 (the deepest well drilled). Drilling losses occurred in the shallow reservoir between 250 m and 280 m and between 400 m and 500 m within the Stratoid series in wells A-3 and A-6, but these shallow zones were not tested. Well A-4 is separated from A-3 and A-6 by several faults (Jalludin, 2010). In well A-4, the top of the Stratoid series is deeper and the rhyolite section, where drilling losses occurred in the other two wells, is absent. The appearance of the high temperature marker mineral epidote (220°C; shown as green in Figure 6) is also deeper in A-4. It is seen 135 m shallower in A-3 and 188 m shallower in A-6. This implies either fault displacement or the geothermal reservoir is deeper to the northeast. In all wells, it appears near the top of the Dalha basalt. Epidote will not form at the temperatures expected in the shallow reservoir. Figure 6 shows orange lines that mark smectite in the wells. The productive zones also show between 1000 m to 1300 m.

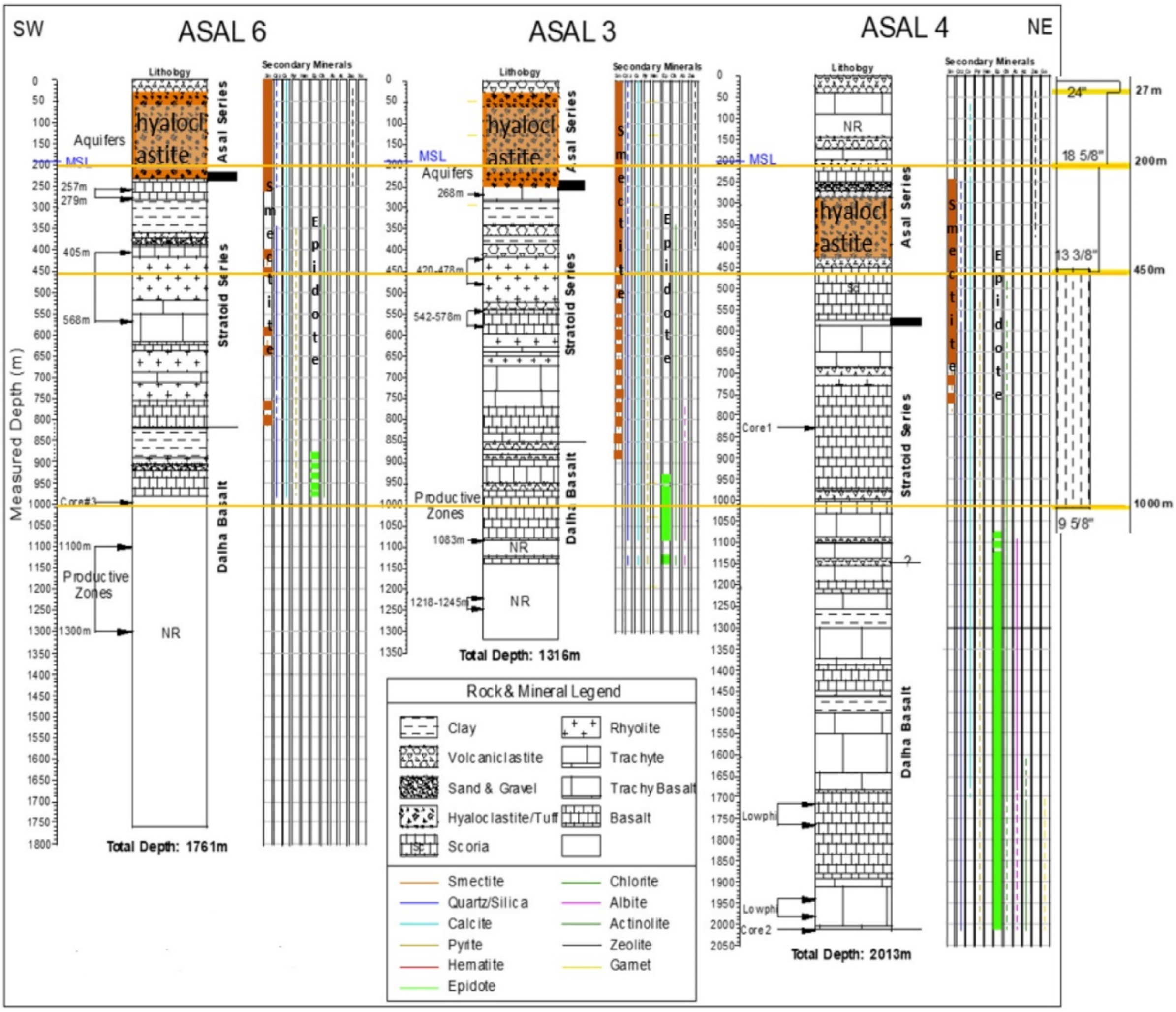


FIGURE 6: Stratigraphy and mineralogy in Asal wells 3,4 and 6 (reproduced from internal report)

4. ASAL FIELD AREA AND LITHLOGY LOGGING

The Asal field is a typical oceanic type rift valley with a very advanced graben displaying axial volcanism. But it is complex in structure because of different periods of active volcanism in the recent Quaternary times, which have very different characteristics depending on the site of appearance. Mostly, Asal series are composed of porphyritic basalt formations and hyaloclastites. The lithological logs of Asal wells 3, 6 and GLG-1 are almost the same; they encountered the same reservoir and have a lithology close to that at the new drilling site. Cuttings were collected every 5 m from Asal 3 and 6 while at GLG-1 cuttings were collected every 2 m for increased accuracy. Figure 7 shows the existing sevens wells in red and well P-1 in blue, which will be drilled next. Figures 8 and 9 show the lithologies of Asal-3 and 6.

4.1 Asal -3, 6 and GLG-1 wells data and the correlation with P-1 and temperature profile

The four boreholes Asal-3, 6, GLG-1 and new drilling site P-1 are situated in the southern zone of the Asal rift. The distance between Asal-3, 6 and GLG-1 is approximately 300 m while the new site P-1 is located almost 1 km northwest of Asal-3 and 6. The two sites Asal-3 and 6 are located near a NW-SE fracture. Well P-1 is located among NW-SE trending faults on the zone which is mapped as a possible fault. Tables 1 and 2 below list details on the wells Asal-3, 6 and GLG-1.

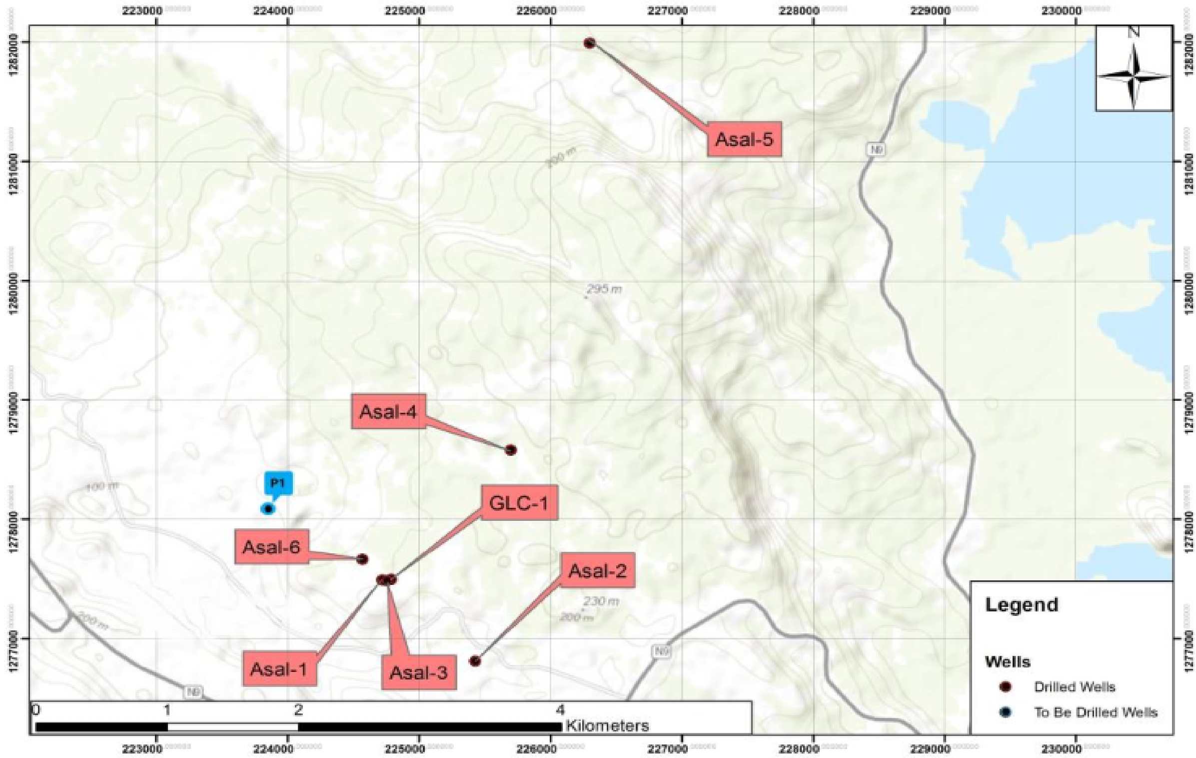
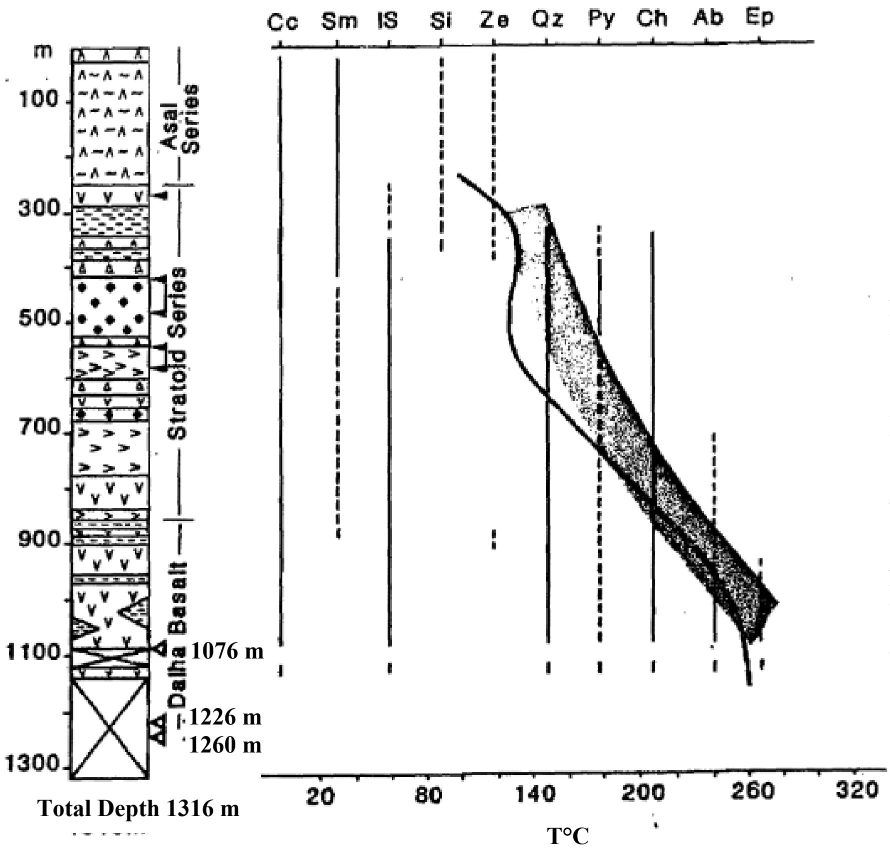


FIGURE 7: Asal well locations (reproduced from internal report)



Cc = calcite;
Sm = smectite;
IS = illite/sericite;
Si = SiO2 polimorph;
Ze = zeolite;
He = heulandites;
Lm = laumontite;
Qz = quarts;
Py = pyrite;
Ch = chlorite;
Ab = albite;
Ep = epidote;
Am = amphibole;
Px = pyroxene;
Ga = garnet;
Wo = wollastonite.

FIGURE 8: Lithology, alteration mineralogy, temperature profile and feed zones in well A-3. Reproduced from Aquater (1989).

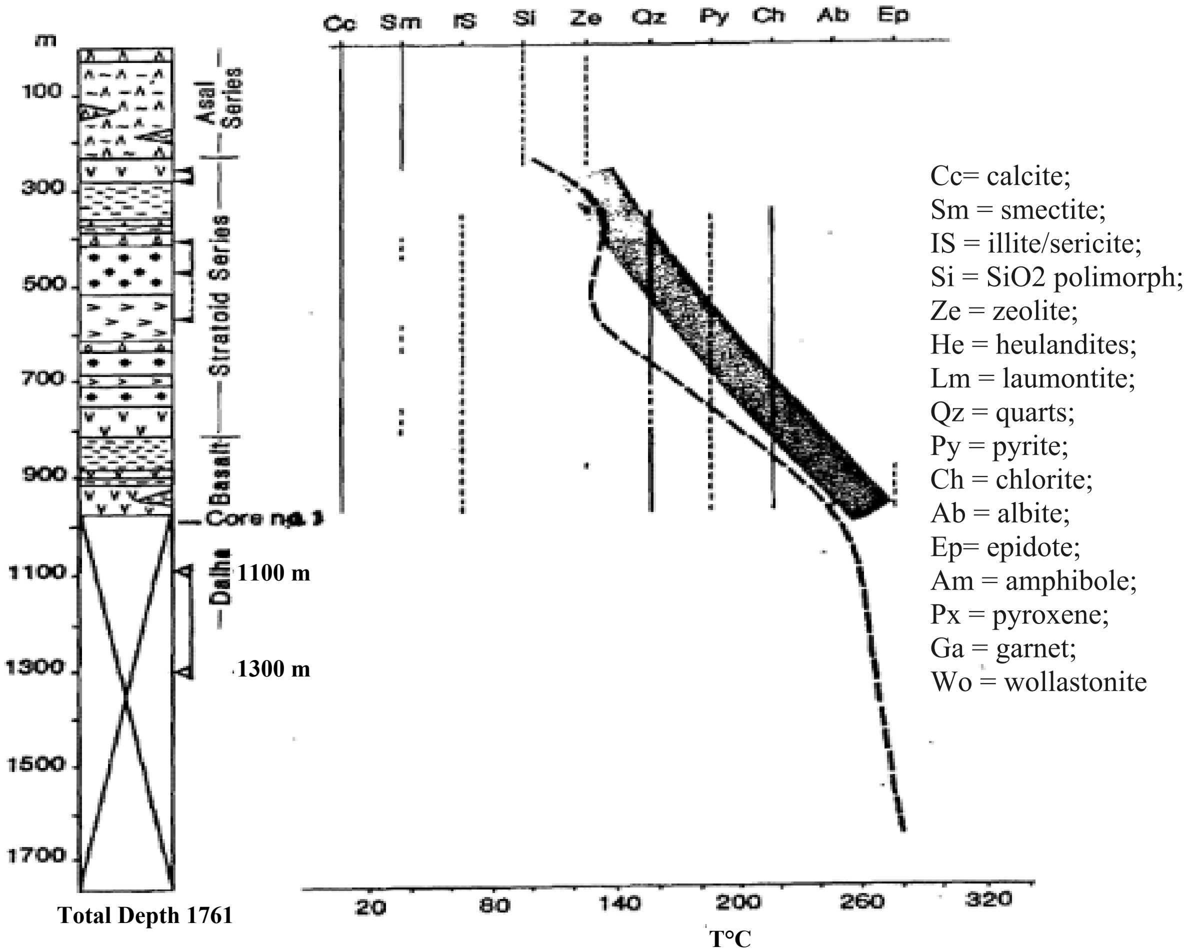


FIGURE 9: Lithology, alteration mineralogy, temperature profile and feed zones in well A-6. Reproduced from Aquater (1989).

TABLE 1: Asal-3, 6 and GLG-1 drilled wells in Asal field

Wells	**Coordinates**			**Depth**	**Feed zones**	**BHT[1]**	**Aquifer formations**
	x (m)	**y (m)**	**z (m a.s.l.)**	**(m)**	**(m)**	**(°C)**	
Asal-3	224800.36	1277342.4	192.665	1316	240-250 400-460 540-550 1050-1075 1225-1250 1275-1316	265	Stratoid basalt series; Contact hyaloclastite/scoria A.S.; Rhyolite of stratoid series; Trachyte of stratoid series
Asal-6	224525.25	1277427.46	183.223	1761	220-270 400-600 1000-1761	281	Dalha basalts series
GLG-1	224790.76	1277500.45	196	450	435	127	Stratoid series; Rhyolite/trachyte stratoid series; Porphyritic basalts; Hyaloclastite; Recrystallized and silicized acid rock; Rhyolite of stratoid series

1: BHT: Bottom hole temperature.

TABLE 2: Formation penetration rates for Asal-3, 6 and GLG-1

Series	Formation	Asal-3			GLG-1			Asal-6		
		T (m)	B (m)	Th (m)	T (m)	B (m)	Th (m)	T (m)	B (m)	Th (m)
Asal series	**Porphyritic basalts**	6,5	25	18,5	5	22	17	0	25	25
	Hyaloclastitee	25	247	222	22	227	205	25	230	205
	Ol-basalt	247	287	40	227	297	70	230	280	50
Stratoid series and Pleistosene clay	**Compact claystone**	287	338	51	297	367	30	280	355	75
	Chloritized porphyric basalt	338	365	27	367	384	17	355	370	15
	Plastic clay	365	383	18	384	426	42	370	385	15
	Altered tuff	383	409	16	426	450	24	385	412	27
	Rhyolite	409	515	106	450	-	-	412	512	100
	Tuff	515	540	25	-	-	-	512	515	3
	Trachyte	540	602	62	-	-	-	515	603	88
	Tuff	602	633	31	-	-	-	603	625	22
	Olivin basalt	633	653	20	-	-	-	-	-	-
	Rhyolite	653	677	24	-	-	-	625	675	50
	Trachyte	677	777	100	-	-	-	675	700	25

T: Top; B: Bottom; Th: Thickness.

4.2 Drilling history and encountered problems (ASAL 3, 6 and GLG-1)

4.2.1 ASAL-3

After drilling the 24” hole section to 200 m, a 20" casing was run with difficulty since the upper part of the hole could not be reamed. The interval between 8 and 62 m was reamed twice with the hole opener only. Nevertheless, the casing got stuck at 140 m. Attempts were made to free the stuck casing by circulating aerated water and foam. Draughts, rotation and quick descent were successful applied, and the rest of the casing was run down to 192 m.

During drilling of the 17½” hole, wait on cement (WOC) drilling continued to 338 m. Circulation losses occurred at 321 m when drilling with foam. In this case, the use of foam did not allow for proper well cleaning. After filling the hole with mud, the water level (WL) was found to be at 200 m. Cement plugging was then carried out by pumping 12,5 tonnes of cement through a 4½” DP set at 297 m. The top of cement was tagged at 247 m. The drilling out of the cement from 247 to 296 m was attempted using aerated water. The WL was still measured at 200 m. Then other cement plugs were pumped down through a 4½" set at 288 m (6,5 ton) and at 258 m (5,6 ton), and another cement plug (6 ton) was pumped at 207 m.

During the drilling of the 12¼” hole section with aerated water, water inlets occurred from 421 m down to 551 m where total circulation loss occurred. The plugging of these high-porosity zones was attempted with 4 plugs and a total of 31 tonnes of cement. During the drilling out of the cement, absorption of 15 m/h was recorded at 514 m depth. To plug it, a 5 ton cement plug was pumped and 6 ton more were squeezed at 402 m. Then, drilling started again with bentonitic mud. A strong absorption was eliminated at 571 m by adding loss circulation material (LCM).

Drilling continued to 860 m depth with bentonitic mud when rupture of the upper part of the penultimate 6¼" DC occurred. After a successful fishing job, with overshot, the drilling was resumed in a very hard basaltic formation. In summary, basalts and hyaloclastics were found down to 247 m and basalts of the stratoid series down to 287 m. Below, there were compact clays which are known as Pleistocene clays, interlayered with basalt, then the stratoid series consisting of trachytes, trachybasalts and basalts were observed. Toward the bottom of the series there are two clay levels. The last one probably marks the passage to the Dahla basalts at 898 m. Permeable levels were found around 250 m at the contact between hyaloclastics and scoriaceous basalts and from 418 m to 553 m in fractured rhyolites.

From 240 m to 250 m, significant mud loss was observed. Also, it is expected that drilling and casing running will be hard and problematic around 280-380 m depth because of the clay formation present at this depth. There are two major permeable intervals: The first at 400-460 m and the second at 540-553 m. Further, very small circulation losses occurred between 553 m and 1,020 m. In this interval, the formations appear almost totally impermeable (Aquater, 1989).

4.2.2 ASAL-6

During the 17½" hole section drilling, a total loss was recorded at 24.5 m in the basalts of the upper unit. Permeability is likely caused by a fracture type as open fractures are common in surface outcrops close to the well. A fissure was intersected at 222.5 m in the lower section of the hyaloclastite unit, seemingly at the contact with a yellowish clay level. This should be a major fissure since any attempt to plug it was unsuccessful. This fissure, as well as the upper one, is dry as long as the water table related to the first aquifer is at about 240 m. The first aquifer was intersected from 267 m to 279 m (top of the Pleistocene claystone). The temperature of this aquifer is close to 100-110°C.

Three major aquifers (temperature around 130°C) were then intersected in the rhyolites: At 396-398 m, 432 m, and 462-468 m depth. The first productive fissure was drilled at 962 m. Circulation losses were sealed with cement plugs. Unfortunately, the loss location at 225 m remained open despite the use of rough clogging cement and concrete plugs. Therefore, the first layer of clay was drilled with foam. Due to caving and battery stucks the 13⅜" casing was run to 281 m (2 m in the clay). Three cement squeeze jobs were carried out before obtaining a successful tightness test result.

During drilling of the 12¼" hole section (323-398 m), numerous cement plugs were installed to support the clay. Once a certain equilibrium had been achieved (mud weight with barite), drilling was resumed and reached a depth of 398 m (total loss). Hence, the hydrostatic column was reduced, causing a series of cavings in the well. The operation was repeated using cement plugs and, in order to avoid any further risk, it was decided to run the 9⅝" casing down to 388 m (a few meters into the tuff), thus totally isolating the clay.

During drilling of the 8½" hole section (398-1761 m), when the partial circulation losses first started, aerated mud was used, and the results were good since the hole remained clean and the circulation losses were limited. Then, the rhyolitic formation was plugged with cement plugs. The first total circulation loss occurred at 962 m and drilling continued with sea water and A3 brine. Drilling proceeded in total loss and without problems to 1761 m (Aquater, 1989).

4.2.3 GLG-1

GLG-1 well was started by drilling the 17½"section with the air drilling method. After advancing down to 16.5 m, there was a total loss zone. Drilling operation were continued with mud and a partial loss to 19.5 m. After 19.5 m, partial loss turned to total loss. Plug cement operations were applied. The interval over 9-11 m, where total loss occurred, has fractures and cracks in the porphyric basalt. The GLG-1 well reached the production zone by entering the total loss zone at 468 m on 10.11.2016. Due to the total loss, the drilling operation was continued with low density mud. The zone between 300 and

367 m depth, consisting of compact clay in the Asal-3 well, began to swell and collapse during the drilling of the total loss interval. Well stabilization was not possible due to the nature of clay zones. Therefore, many difficulties were encountered during the drilling operation. Another problem was that the rig capacity was 40 tonnes too small, which also meant that the desired total depth (TD), which was beyond 1000 m, could not be reached. Despite these problems, the well ended at 508 m depth and reached the production zone. A 4½" casing was snagged at 464 m because of the swelled clay zone. Several attempts were made to set the casing, but the desired depth was not reached.

It was decided to pull the casing out of the borehole because it was assumed that the production zone was already blocked and plugged with clay and the well could not produce under these conditions. It was decided to clean the wellbore and plug the problematic zones with a cement job. After the casing was pulled out of the borehole, the well was reamed down to 365 meters, the tally was pulled out of hole and preparations were made for the cement plug operation. $CaCO_3$ was pumped before the cement plug operation to prevent the cement from reaching the production zone. Three cement plug operations were made in three sessions, and a total amount of 46 bbls cement was pumped between 412-286 meters. When the cement was drilled out, it was observed that the total loss had been eliminated. Afterwards, clay particles were observed at the shakers at 399 m depth when the tally ran in hole. Because the tally got stuck multiple times during the drilling operation, it was decided to pull the tally out of hole and conduct another cement plug operation.

In total, 6 different cement plug operations were conducted at different depths, with different volumes and pressures but no well stabilization was achieved. In order to achieve well stabilization, high density mud was used after the last cement plug operation. After experiencing a partial loss with a rate of 25 bbls/hr at 452 meters, the drilling operation was completed at 465 meters after drilling a further 13 meters into the production zone. The 4½" casing (full casing at 285.8-434.2 meters and slotted casing at 434.2-464.5 meters) was run in hole successfully. The casing was set at a depth of 464.5 m and the mud in the well was replaced with water.

The drilling of GLG-1 was continued without total loss or other problems in this zone. When the production zone was drilled and total loss was experienced, well stabilization was lost and swelling occurred in the production zone. In addition, due to the fact that the target of Asal-3 well was a deep reservoir located at 1100 m, the total loss zones observed at shallow depths were addressed by multiple cement plug operations without risk of plugging the reservoir. However, since the possibility of plugging the reservoir is high when a shallow reservoir is targeted, the cement operation could not be performed in this case. With every run-in hole and pull out of hole operation, the well stabilization was lost and collapse and swelling occurred at the clay zone.

4.3 Well tests of ASAL-3 and 6

Asal-3 and Asal-6 were tested between June and August 1987 and between April and June 1988, and were confirmed to be productive wells. Due to the high scaling found in Asal-6, it did not respond to the flow test – in other words it is not stabilized like Asal-3. Asal-3 produces about 40 kg/s of fluid whereof 4-5 kg/s is steam. Asal-3 and Asal-6 are cross the basaltic Dalaha series formation at 900-1800 m, a high-temperature liquid-dominated geothermal system with a temperature of 263°C, and produce geothermal brine with a salinity of 120 g/L from the deep reservoir. Figures 10 and 11 show the temperature and pressure profiles attained during the discharge test of Asal-3. The pressure and temperature of Asal-3 at 1200 m depth are about 86 bar and 263°C as shown in the graphs below.

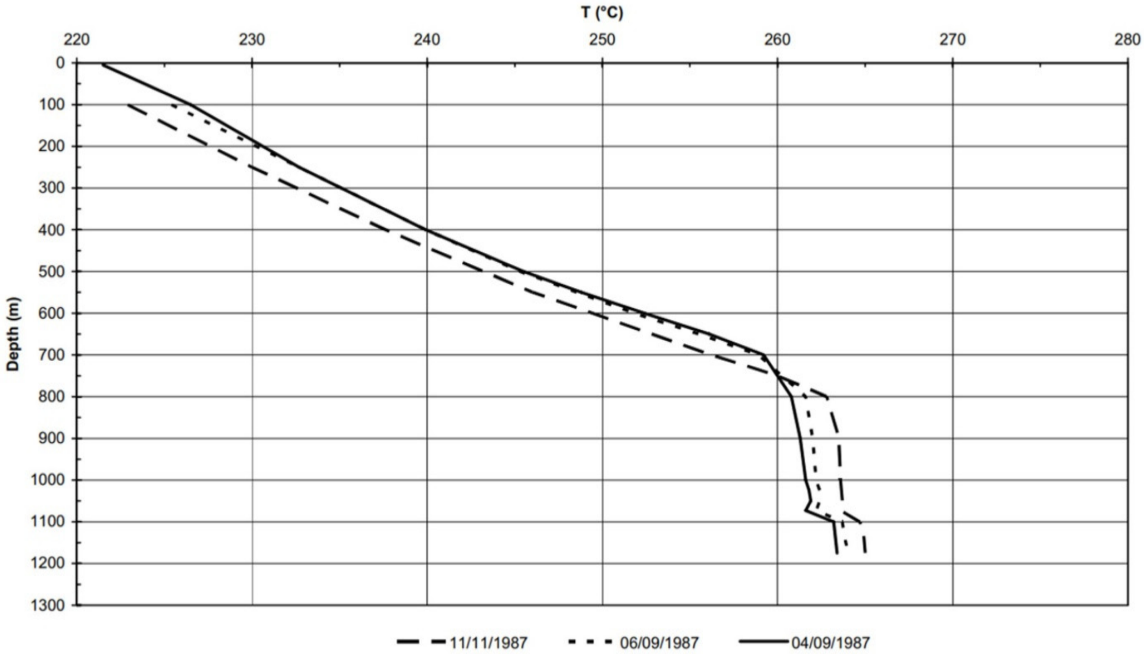


FIGURE 10: Temperature profile during discharging test of Asal-3 (Elmi, 2005)

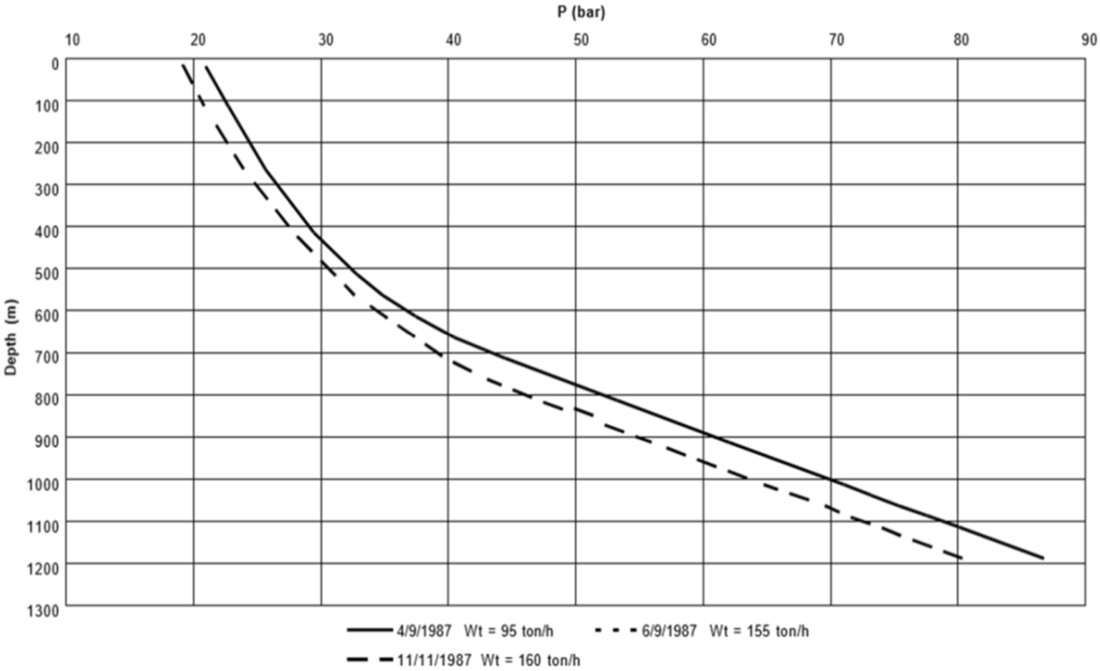


FIGURE 11: Pressure profile during discharge test of Asal-3 (Elmi, 2005)

5. GENERAL GEOTHERMAL WELL DESIGN OVERVIEW

The geothermal well design procedure takes into consideration the purpose and tenacity of the well, as well as the subsurface conditions expected to be encountered throughout the drilling process. The equipment, materials, and drilling procedures are selected to ensure well completion and a long lifetime of the well.

The strategy for a proper and safe well design, following the recommendations of the *African Union Code of Practise for Geothermal Wells*, necessary to drill and complete a deep geothermal well safely is addressed below:

- Collect all available data on subsurface conditions from the wellhead to the well target.
- Collect information on previous wells that have been drilled in the area where a new well will be drilled, such as accounts of drilling problems that have been experienced, information about the depth of the clay zone, accounts of loss of well stability, and lost circulation depths to learn from problems encountered in that area.
- Establish expected geological formations.
- Estimate temperature and pressure versus depth.
- Determine safe casing shoe depths for each casing string back to surface using: Maximum design pressure; effective containment pressure; knowledge of formation integrity; and knowledge of anticipated problem zones.
- Specify casings and well completion.
- Specify cementing materials and programmes.
- Detail wellhead specifications.
- Specify drilling fluids, drill string assemblies.

One of the most important aspects to be considered is the selection of casing specifications, casing shoe depths, material selection for H_2S sour service and how the well is completed. A good well design yields a well that is safe to operate with a reasonably long life. Several innovations to advance appropriate well design have been conducted through the revision of the existing standard, which has led to the establishment of the *African Union Code of Practice for Geothermal Drilling* (African Union's Regional Geothermal Coordination Unit, 2016).

6. CASING DESIGN

The main purpose of the casing design is to permit a well to be drilled in a safe manner without failure through providing structural integrity of the well against forces obtruded during drilling and to fulfil the well's objective without necessitating a workover during its lifetime. The casing design should consider the economic side without compromising safety. A proper design for a geothermal well should consider predicted conditions during drilling and operation of the well, which may decrease the lifetime of a well. This is done to assure that the selected casings for the well have a substantial leeway of strength to accommodate anticipated stress at all depths throughout the well. Aspects included in the *African Union Code of Practice for Geothermal Drilling* (African Union's Regional Geothermal Coordination Unit, 2016), which need consideration are:

- Casing failure due to internal and external loads.
- Protecting the well against corrosion, erosion or collapse.
- Safe containment of well fluids.
- Anchoring of wellheads during drilling and operation of the well.
- Control against subsurface aquifer contamination.
- Resistance to hydrogen crumbling in environments affluent in H_2S gas.
- Longevity of the well.

Crucial parts to be considered in the well design are the casing strings. They consist of numerous pipe steel casings which are run into every well and detained in position by a cement bond formed between the casing wall and the well formation or between casing strings. The steel casings selected are API spec 5CT and API spec 5L standard. Under the API standards, casings are classified according to the manufacturing process, the steel grade, joint type, length range and wall thickness. The casing grade determines the strength of the casing steel against tensile loads, burst and axial loads, while the strength against collapse is principally attributed to the wall thickness of the casing (Finger and Blankenship, 2010). Table 3 shows the BPD temperatures of pure water with no dissolved gas with water table at 200 m (the xsteam table calculation for saline water).

TABLE 3: Boiling point depth (BPD) temperatures of pure water with no dissolved gas and water table at 200 m

Hole depth (m)	**Hydrostatic fluid pressure at 20°C (MPa)**	**Hydrostatic fluid pressure at BPD (MPa)**	**BPD temperature (°C)**
200	0.00	0.00	100
210	0.10	0.09	119
220	0.19	0.19	132
240	0.39	0.36	149
260	0.58	0.54	162
280	0.78	0.72	172
300	0.98	0.89	180
350	1.47	1.32	196
400	1.95	1.75	208
500	2.93	2.57	227
600	3.91	3.37	242
700	4.89	4.16	254
800	5.87	4.93	264
1000	7.82	6.43	281
1200	9.78	7.87	295
1400	11.70	9.26	306
1700	14.70	11.27	321
2200	19.60	14.40	339
2700	24.50	17.30	354
3200	29.30	19.90	365

Geothermal wells have the following casings:

- *Conductor pipe*: Runs to a shallow depth offering a foundation platform and protects against the washing-out of the loosely held top formation.
- *Surface casing*: Provides protection against collapse of weak formations, avoiding blow out at shallow depth and supports the blowout preventer for safe drilling of the next hole.
- *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 to facilitate 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 zones of the well. It also offers a conduit for reservoir fluid movement to the surface.
- *Liner casing*: This is a perforated casing that is set inside the production casing and allows flow of reservoir fluid into the well.

The casing program for GLG-1 exploration well (slim hole) at shallow depth of 700 m consists of a surface casing of 13⅜", anchor casing of 9⅝", production casing of 7", and slotted liners of 4½" diameter. However, for the upcoming production well, a new casing program will be implemented. This revised program will adhere to regular diameter specifications and will be based on the guidelines outlined in the African Union Code of Practice for Geothermal Wells 2016, ensuring optimal design for geothermal production. Figure 12 in this report illustrates the new casing program.

6.1 Casing setting depths

The casing shoe setting depth is based on assumptions on pore pressure and fracture gradient of the rock formation. The minimum casing shoe depth is determined by collecting information from nearby wells, such as geological formation, temperature and pressure profiles, or by following the casing design process described in the *African Union Code of Practice for Geothermal Drilling* (2016) for secure, successful and steady wells.

The design starts from the bottom of the well up to the surface and the setting depths are selected based on pore pressure. In this case, it is assumed that the liquid is boiling at depth (BPD curve), with 12% NaCl and the calculated fracture gradient. Figure 13 shows a well design for a TD of 1300 m with several casing sections and shoe depths of each section. The Eaton equation was used where the fracture gradient is unknown:

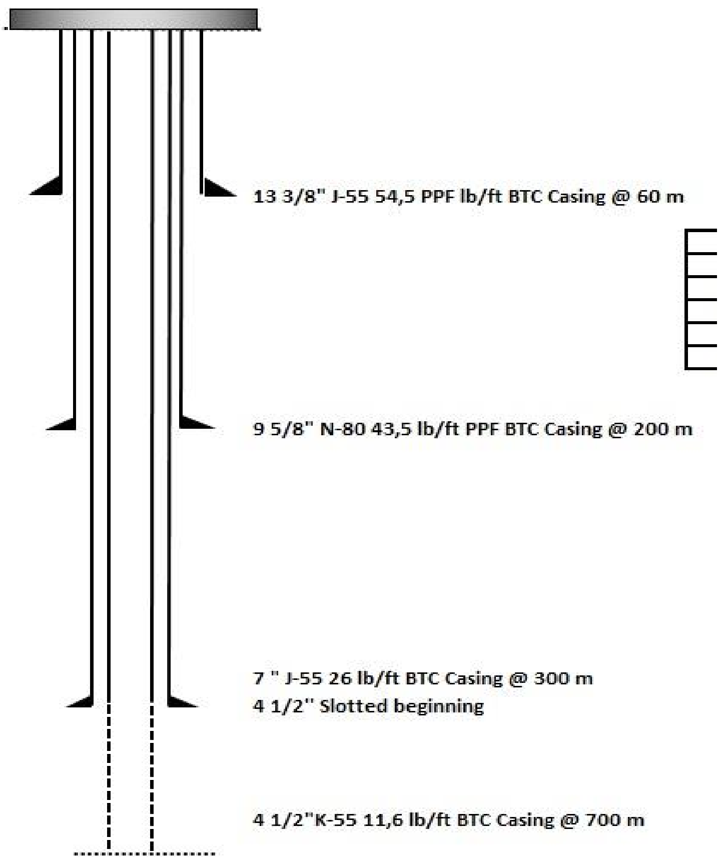


FIGURE 12: GLG-1 well design

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

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

where ρ = Density of the rock type (kg/m^3);
g = Acceleration due to gravity (9.81 m/s^2); and
h = Depth (m).

The following rock densities are assumed: Basalt with an average of 2900 kg/m^3, hyaloclastite 2500 kg/m^3, pliocenic shale 2400 kg/m^3 and rhyolite 2500 kg/m^3 (Hatherton and Leopard, 1964), and these have been used in the Eaton formula. Poisson's ratio ranges between 0.1 to 0.4 (Gercek, 2006) depending on rock type. The average Poisson's ratio used for basalt is 0.225, for hyaloclastite it is 0.25, for pliocenic shale it is 0.185 and for rhyolite 0.215. The maximum wellhead pressure, as calculated using the xsteam table for saline water, is 97 bar assuming a static column of steam from the bottom of the well and a maximum temperature of 310°C as show in Figure 14. The well design sketch and minimum setting depths are in accordance to the steam table calculation by following the process described by the African Union's Regional Geothermal Coordination Unit (2016). The resulting casing shoe depths are 250 m, 450 m and 800 mas shown in Figure 13.

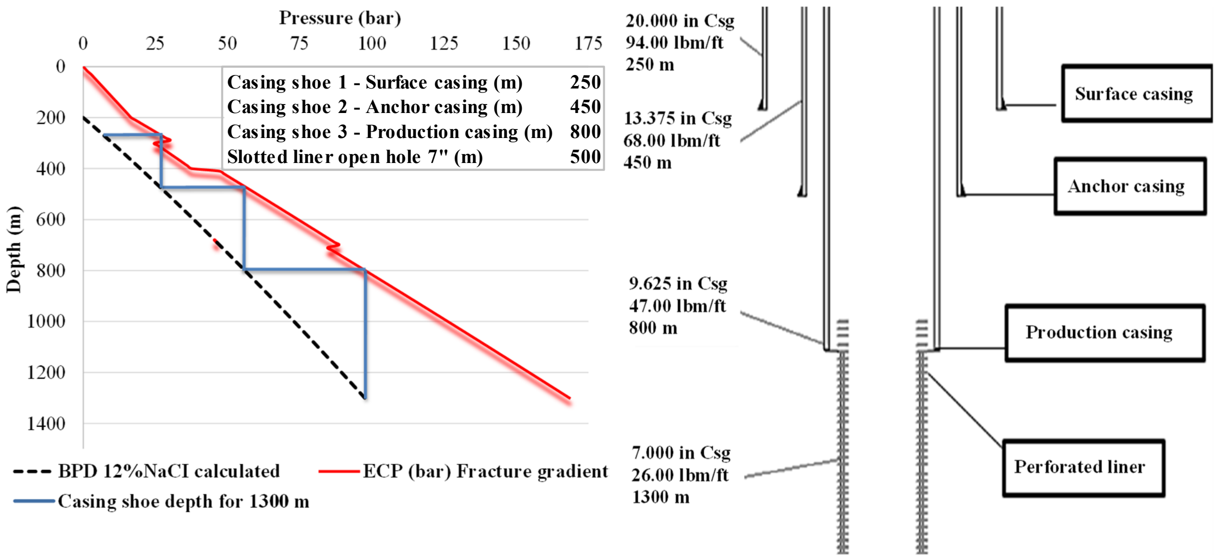


FIGURE 13: Well design sketch and minimum setting depths according to the x steam table calculation and the process described in the *African Union Code of Practice* (2016). Casing shoe depths are 250 m, 450 m and 800 m.

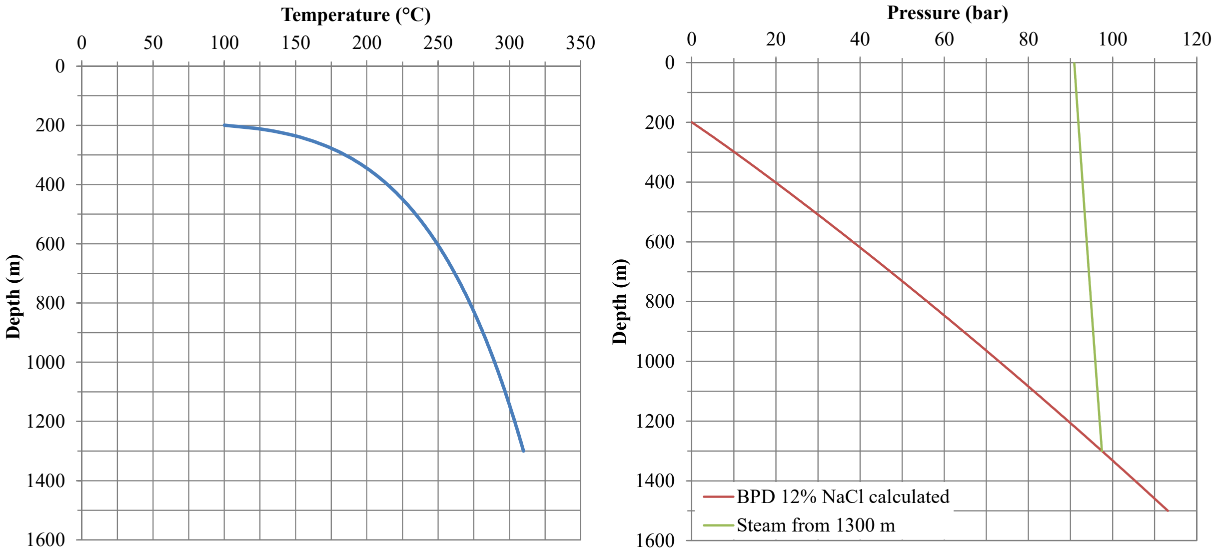


FIGURE 14: The maximum wellhead temperature and BPD pressure at 1300 m

6.2 Casing grade selection for the new well

This section on the proper election of the casing materials is very important to prevent failure due to internal and external loads, high salinity or H_2S gas, and to ensure safe drilling and a long lifetime of the well. Below, different type of grades with different material compositions are described. For the best selection, we refer to the *African Union Code of Practice for Geothermal Drilling* (2016) and the *Drilling data handbook* (Gabolde and Nguyen, 2014). Table 4 lists possible casing grades if H_2S gas is present.

TABLE 4: Casing grades for sour service environment
(African Union's Regional Geothermal Coordination Unit, 2016)

Where gas may be present such H_2S (sour materials)	API SPEC 5CT casing grades
	L-80, K-55, T-95, C-90, H-40

6.3 Casing calculation

The proposed calculations are completed once the minimum casing setting depth for each section has been determined. Casing stress design is utilized to determine the appropriate casing grade, weights, and diameter for the well, with a focus on protection against sour environment corrosion and collapse. Additionally, the chemical compositions of different casing grades are taken into consideration, as depicted in Figure 15 from the API standard. A comparison of the mechanical properties of K-55 and L-80 is also provided in Table 5. Standard design factors specified in the African Union Code of Practice are outlined in Table 6. The impact of temperature on various casing properties is illustrated in Figure 16. Special attention is required in areas where extremely saline fluid (120 g/L) is anticipated, which is three times the salinity of sea water. Table 7 shows the casing grades selected for each section of the new well, considering salinity issues. Referring to Figure 13, the casing specifications for the new well include 20″ surface casing, 13⅜″ anchor casing, 9⅝″ production casing, and 7″ slotted liners, with the chosen grades detailed in Table 7 for all casing strings.

The calculation of the casing strength needed to protect against burst pressure, axial tensile/compressive force, and collapse pressure is essential as it determines the appropriate casing grade selection for the well. The mechanical properties of the casing strings were taken from the *Drilling Data Handbook (9th ed.)* (Gabolde and Nguyen, 2014). Based on the calculations, a suitable casing grade and weights are selected for the 1300 m production well (Table 7). The design calculations assume that the well is full of steam from the bottom to the surface which represents the worst-case load scenario.

Group	Grade	Type	C		Mn		Mo		Cr		Ni	Cu	P	S	Si
			min.	max.	min.	max.	min.	max.	min.	max.	max.	max.	max.	max.	max.
1	*2*	*3*	*4*	*5*	*6*	*7*	*8*	*9*	*10*	*11*	*12*	*13*	*14*	*15*	*16*
1	H40	—	—	—	—	—	—	—	—	—	—	—	0,030	0,030	—
	J55	—	—	—	—	—	—	—	—	—	—	—	0,030	0,030	—
	K55	—	—	—	—	—	—	—	—	—	—	—	0,030	0,030	—
	N80	1	—	—	—	—	—	—	—	—	—	—	0,030	0,030	—
	N80	Q	—	—	—	—	—	—	—	—	—	—	0,030	0,030	—
	R95	—	—	0,45[c]	—	1,90	—	—	—	—	—	—	0,030	0,030	0,45
2	M65	—	—	—	—	—	—	—	—	—	—	—	0,030	0,030	—
	L80	1	—	0,43[a]	—	1,90	—	—	—	—	0,25	0,35	0,030	0,030	0,45
	L80	9Cr	—	0,15	0,30	0,60	0,90	1,10	8,00	10,0	0,50	0,25	0,020	0,010	1,00
	L80	13Cr	0,15	0,22	0,25	1,00	—	—	12,0	14,0	0,50	0,25	0,020	0,010	1,00
	C90	1	—	0,35	—	1,20	0,25[b]	0,85	—	1,50	0,99	—	0,020	0,010	—
	T95	1	—	0,35	—	1,20	0,25[d]	0,85	0,40	1,50	0,99	—	0,020	0,010	—
	C110	—	—	0,35	—	1,20	0,25	1,00	0,40	1,50	0,99	—	0,020	0,005	—
3	P110	e	—	—	—	—	—	—	—	—	—	—	0,030[e]	0,030[e]	—
4	Q125	1	—	0,35		1,35	—	0,85	—	1,50	0,99	—	0,020	0,010	—

FIGURE 15: Chemical compositions of different casing grades (Gabolde and Nguyen, 2014)

TABLE 5: Comparison of mechanical properties of K-55 and L-80

OD (inches)	Size	Thread	Grade	Collapse resistance (MPa)	Internal yield pressure (MPa)	Minum yield strength (MPa)	Pipe body yield strength (1000 daN)
20	94	BTC	K-55	3.6	14.5	379	659
20	94	BTC	L-80	3.6	21.1	551	958
13⅜	68	BTC	K-55	13.4	23.8	379	476
13⅜	68	BTC	L-80	15.6	34.6	551	692
9⅝	47	BTC	K-55	26.8	32.5	379	332
9⅝	47	BTC	L-80	32.8	47.3	551	483
7 slotted	26	BTC	K-55	29.3	34.3	379	185
7 slotted	26	BTC	L-80	37.3	49.9	551	269

TABLE 6: Standard design factors (African Union's Regional Geothermal Coordination Unit, 2016)

Stress condition	Loader cases	Calculation	Min. design factor
Triaxial	As per application and caveats in new version 2.10.1.2	$\frac{\textbf{minimum materials yield stress}}{\textbf{minumum total equivalent triaxial stress}}$	1.25
Axial	Tensile force during cementing	$\frac{\textbf{minimum tensile strength}}{\textbf{maximum tensile load}}$	1.8
	Axial load after cementing Compressive strength	$\frac{\textbf{minimum compressive strength}}{\textbf{resultant compressive force}}$	Not stated
	Lifting force on anchor casing	$\frac{\textbf{minimum tensile strength}}{\textbf{maximum tensile load}}$	1.8
	Thermal load in anchor casing	$\frac{\textbf{anchor casing tensile strength}}{\textbf{rising casing compressive strength}}$	1.4
Hoop	Helical buckling due to self-weight plus thermal load (uncemented liner)	$\frac{\textbf{minimum yield stress} * \textbf{Rj}}{\textbf{total compressive stress}}$	1
	Internal pressure at shoe during cementing	$\frac{\textbf{internal yield strength}}{\textbf{differential internal pressure}}$	1.5
	Wellhead internal pressure where wellhead is fixed to casing	$\frac{\textbf{steel yield strength}}{\textbf{maximum tensile stress}}$	1.5
	Wellhead internal pressure (shut-in steam/gas as after drilling)	$\frac{\textbf{internal yield stress} * \textbf{Ri}}{\textbf{wellhead pressure}}$	1.8
	External pressure collapse (during cementing)	$\frac{\textbf{pipe collapse pressure}}{\textbf{differential external pressure}}$	1.2
	External pressure collapse (during production)	$\frac{\textbf{pipe collapse pressure}}{\textbf{diffrential external pressur}}$	1.2

Grade	**Temperature (°C)**						
	20	100	150	200	250	300	350
	API yield strength (factor)						
J55-K55	1.00	0.94	0.90	0.90	0.85	0.85	0.70
L80/C90/T95	1.00	0.96	0.92	0.90	0.88	0.85	0.81
	Tensile strength (factor)						
For all grades	1.00	0.96	0.92	0.90	0.88	0.86	0.84
Young modulus of elasticity (GPa)							
All gradess	210	205	201	197	194	190	185

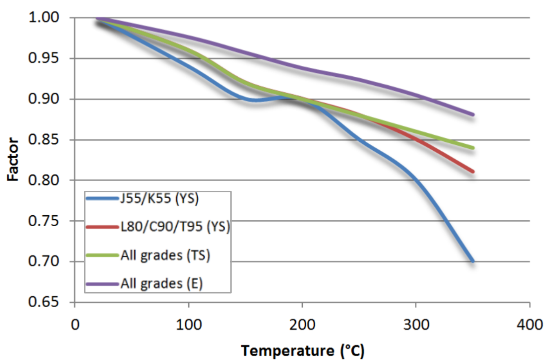


FIGURE 16: The effect of temperature on different casing grades
(African Union's Regional Geothermal Coordination Unit, 2016; Standards New Zealand, 2015)

TABLE 7: Casing grades selected for every section for the new well taking in account the salinity issues

OD (in)	Nominal weight (lb/ft)	Thread	Grade	Depth (m)	Comments	Collapse resistance (MPa)	Internal yield pressure (MPa)	Pipe body yield strength (1000daN)	Mandrel drift diameter (mm)
20	94	BTC	K-55	0-250	No need to select a special casing as this section is used to support the rig	3.6	14.5	659	481
13⅜	68	BTC	L-80	0-450	Need a grade L80 at least for the first 3 joints of casing pipe assuming about 36 m	15.6	34.6	692	311.33
9⅝	47	BTC	L-80	0-800	Referring to Table 5 above	32.8	47.3	483	216.53
7 slotted	26	BTC	L-80	770-1300	Referring to Table 5 above	37.3	49.9	269	156.22

7. CASING STRESS DESIGN

The axial stress in casings is caused by three main parameters: The weight of the casing, the temperature (compression and expansion), and restraint due to cement or connection at the wellhead or downhole hanger. The *African Union Code of Practice for Geothermal Drilling* (2016) specifies that casing stresses have to be assessed either by calculating each individual stress or calculating the triaxial stress using this standard API TR 5C3. The triaxial stress calculation combines all the stresses acting on the casing. In this report, we calculate each individual stress to obtain the minimum safety design factor as shown in the Table 6.

The forces affecting the casing are as follows (Figure 17):

- Burst due to internal pressure exceeding the pressure load outside the casing;
- Collapse due to higher pressure acting outside of the casing than inside; and
- Compression due to heating of the well and tension due to cooling.

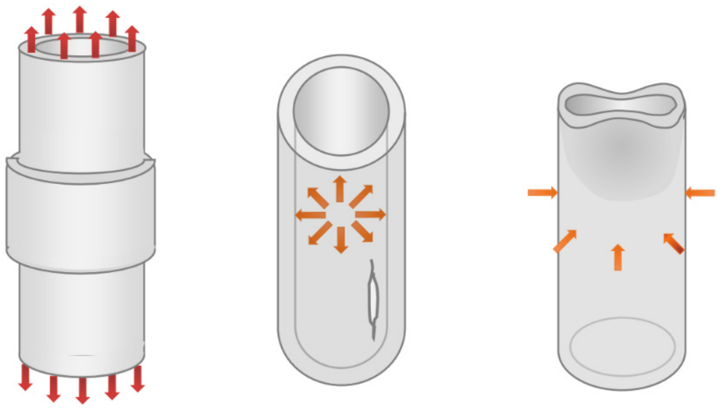


FIGURE 17: Different loads affecting the casing

7.1 Axial loading before and during cementing

Until the annular cement sets around the casing, the tensile force at any depth includes the weight of the casing in air plus the weight of the casing contents reduced by the buoyancy effects due to any fluid displaced by the casing in the well (African Union's Regional Geothermal Coordination Unit, 2016):

$$F_{csg\ air\ wt} = L_z.W_P.g \tag{3}$$

where L_z = Total vertical length of casing (m);
W_p = Nominal unit weight of casing in the air (kg/m); and
g = Acceleration due to gravity (9.81 m/s^2).

As stated in the *African Union Code of Practices for Geothermal Drilling* (2016), buoyancy is the difference between air weight of the casing (Fcsg air wt) and the hook load (Fhookload). Positive buoyancy acts downward and negative buoyancy acts the other way around:

$$F_{buoyancy} = \left(F_{hookload} - F_{csg\ air\ wt}\right) = \left(F_{csg\ contents} - F_{displaced\ fluids}\right) \tag{4}$$

where $F_{csg\ contents}$ = $\sum \rho_{if} \cdot L_{if} \cdot \frac{\pi d^2}{4} \cdot g$; and
$F_{displaced\ fluids}$ = $\sum \rho_{ef} \cdot L_{ef} \cdot \frac{\pi D^2}{4} \cdot g$.

7.2 Axial load after cementing

In the context of wellbore integrity, it is crucial to understand the axial forces exerted on the casing string, particularly after cementing near the surface and at the shoe of the casing. Axial forces refer to the forces acting along the length of the casing kg/l, which can arise from various sources such as pressure differentials and thermal expansion. The calculation of the resulting net force involves considering the static force present in the casing at the time the cement is setting, in addition to any other casing loadings. If the stress calculated exceeds the stress tolerable by the casing, a plastic or strain-based design approach may be required to ensure structural integrity. Furthermore, temperature changes near the surface during drilling, induced by the circulation of cool drilling fluid, can lead to variations in axial force and must be taken into account in the design and operational considerations of the well. The change in axial force due to temperature changes close to the surface during drilling caused by cool fluid circulating is:

$$F_c = E \cdot \alpha(T_1 - T_2)A_P \tag{5}$$

The resulting axial force is:

$$F_r = F_p + F_c \tag{6}$$

$$F_t = E \cdot \alpha(T_1 - T_3)A_P \tag{7}$$

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

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

7.3 Tension at anchor casing due to the lifting force of the fluid

A lifting force is applied to the anchor casing by thermal expansion of the production casing string where the mechanical design allows it to interfere with parts of the wellhead. The integrity of the anchor casing and the wellhead is protected by ensuring that potential failure would occur elsewhere. The lifting force is:

$$F_w = \frac{\pi}{4} \times P_w \times d^2 \times 10^{-3} - F_m \tag{9}$$

$$Design\ factor = \frac{anchor\ casing\ tensile\ strength}{rising\ casing\ compressive\ strength} \geq 1.8$$

7.4 Axial load of uncemented liners with buckling and bending

The uncemented liners are either hung in tension from the liner top or supported at the shoe in compression. The liners in this case are supported at the shoe and hence should be analysed for helical buckling. The total fibre compressive stress in an uncemented liner that is subjected to axial self-weight and helical buckling is:

$$f_c = L_z \times W_P \times g \times \left\lfloor \frac{1}{A_P} + \frac{De}{2I_P} \right\rfloor \tag{10}$$

$$Design\ factor = \frac{minimum\ yield\ stress\ \times R_j}{total\ compressive\ stress} \geq 1$$

7.5 Maximum differential internal pressure during cementing

At the time of cementing, the maximum differential internal pressure of the casing string occurs near the shoe or stage cementing ports when the following conditions apply:

- The casing string is filled with cement slurry;
- The annulus either contains a column of water or is subject to formation pressure; and
- Constriction within the casing is sufficient to hold the differential pressure.

The maximum differential pressure is:

$$\Delta P_{internal} = \left[L_z \rho_c - L_f \rho_f \right] \times g \tag{11}$$

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

7.6 Maximum differential internal pressure after cementing

After cementing, the maximum differential internal pressure will occur at the surface. In this study the scenario where steam is present at the wellhead is looked at:

$$Design\ factor = \frac{internal\ yield\ pressure\ \times\ R_i}{wellhead\ pressure} \geq 1.8 \tag{12}$$

7.7 Axial and circumferential tension on casing anchoring wellhead

If the wellhead is fixed to the casing, a biaxial stress condition exists. The combined effects of axial and circumferential tension are calculated as below:

$$f_t = \frac{\sqrt{5}}{2} \times \frac{P_w d}{(D - d)} \tag{13}$$

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

7.7.1 Maximum external pressure after cementing

At a later stage of the casing cementing operation, the maximum differential external pressure occurs near the casing shoe when the casing annulus is filled with dense cement slurry and the casing is filled with water. The maximum differential external pressure is:

$$\Delta P_{external} = \left[L_z\, \rho_c - L_z \rho_f\right] \times g \tag{14}$$

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

7.7.2 Maximum external pressure during production

During geothermal production, the maximum external differential pressure occurs near the casing shoe when the annulus is at formation pressure (P_f) and the internal pressure is controlled by well drawdown. In the worst case, the internal pressure at the casing shoe can affect the operating wellhead pressure. The pipe collapse strength is de-rated for the temperature at the shoe:

$$Design\ factor = \frac{pipe\ collapse\ pressure}{differential\ external\ pressure} \geq 1.2 \tag{15}$$

8. RESULTS

The design calculations for the new well are presented in Tables 8-18 below. These calculations have been conducted in accordance with the African Union Code of Practice for Geothermal Drilling (African Union's Regional Geothermal Coordination Unit, 2016). Sour service materials casing grades have been chosen for this project, including K-55 for the surface casing, and L-80 for the anchor casing and production section, as detailed in Table 8.

TABLE 8: Resulting casing selections for well P-1

Casing size (inches)	**20**	**13⅜**	**9⅝**	**7**
Grade	K-55	L-80	L-80	L-80
Weight (lb/ft)	94	68	47	26
Inside diameter (mm)	485.7	315.3	220.5	159.4
Drift diameter (mm)	481	311.4	216.5	156.2
Collapse resistance (MPa)	3.6	15.6	32.3	37.3
Wall thickness (mm)	11.1	12.2	12	9.2
Tensile strength (1000-daN)	659	692	483	269
Minimum yield strength (MPa)	379	551	551	551
Steel cross section (mm^2)	17366	12545	8756	4870
Thread type	BTC	BTC	BTC	BTC

8.1 Collapse / burst pressures during cementing

The collapse and burst pressure calculations were done by assuming that the annulus is filled with 1800 kg/m^3 of cement slurry and with water of 1000 kg/m^3 at 30°C inside the casing. The results for the different casings are presented in Tables 9 and 10.

TABLE 9: External pressure collapse during cementing

Casing size and grade	Casing weight (lb/ft)	Length (m)	External pressure, ΔP (MPa)	Collapse resistance (MPa)	Calculated	Min. design factor
Surface casing (20″) K-55	94.5	250	1.962	3.6	1.83	1.2
Anchor casing (13⅜″) L-80	68	450	3.532	32.8	4.42	1.2
Production casing (9⅝″) L-80	47	800	6.278	15.6	5.22	1.2

TABLE 10: Internal pressure collapse burst during cementing

Casing size and grade	Casing weight (lb/ft)	Length (m)	Internal pressure, $\Delta P_{internal}$ (MPa)	Internal yield pressure (MPa)	Calculated	Min. design factor
Surface casing (20″)K-55	94.5	250	2.158	14.5	6.72	1.50
Anchor casing (13⅜″) L-80	68	450	3.728	34.6	9.28	1.50
Production casing (9⅝″) L-80	47	800	6.475	47.3	7.31	1.50

8.2 Axial loading before and during cementing

Table 11 shows the results for the axial forces acting on the different casings before and during cementing, assuming the worst case, when the internal fluid is water and the displaced fluid is cement.

TABLE 11: Before and during cementing

Casing	Casing weight (lb/ft)	Internal fluid/ water	Displaced fluid/ cement	Fcsg air wt (kN)	Max. tensile load (kN)	Yield strength (kN)	Calc.	Min. design factor
Surface casing (20″)	94.0	453.9	893.8	343	-96.9	6581.7	-67.9	1.8
Anchor casing (13⅜″)	68	344.33	719.4	446.4	71.30	6912.3	96.95	1.8
Production casing (9⅝″)	47	299.38	662.58	548.8	185.60	4824.56	25.99	1.8

8.3 Axial loading after cementing

After cementing the axial loading force can stay positive or change to negative due to a temperature increase or decrease in the well.

8.3.1 Axial load due to temperature increase

The axial load can rise after the cementing job when temperatures increase in the well. Three scenarios have were tested where the temperature of the surface, anchor and production casings were set to 30°C, 35°C and 40°C. Correspondingly, the maximum temperature of the surface, anchor and production casings were assumed to be 95°C, 127°C and 183°C, respectively. The negative values indicate a compressive force, which means that the buoyancy force is acting upward. The design factor in the older version of the NZ standard (1991) was 1.2 but in the revised standard (both NZ and AU version), it has been omitted for casings that will thermally yield and a limited plastic strain design needs to be applied as stated in the *African Union Code of Practice* in clause 2.10.3.4, but this is out of the scope of this report. The results for the axial force due to rise in temperature are listed in Table 12.

TABLE 12: Axial force due to rise in temperature

	T_1 (°C)	T_3 (°C)	Tensile force Ft (kN)	Resultant force Fr (kN)	Min. yield strength (kN)	Calculated	Min. design factor
Surface casing (20″)	30	20	463	366	6581.7	17.98	1.2
	35	20	694	597	6581.7	11.02	1.2
	40	20	926	829	6581.7	7.94	1.2
Anchor casing (13⅜″)	**T_1 (°C)**	**T_3 (°C)**	**Tensile force Ft (kN)**	**Resultant force Fr (kN)**	**Min. yield strength (kN)**	**Calculated**	**Min. design factor**
	30	20	334	406	6912.3	17.03	1.2
	35	20	501	573	6912.3	12.06	1.2
	40	20	668	740	6912.3	9.34	1.2
Production casing (9⅝″)	**T_1 (°C)**	**T_3 (°C)**	**Tensile force Ft (kN)**	**Resultant force Fr (kN)**	**Min. yield strength (kN)**	**Calculated**	**Min. design factor**
	30	20	233	419	4824.6	11.51	1.2
	35	20	350	536	4824.6	9.00	1.2
	40	20	467	652	4824.6	7.40	1.2

8.3.2 Axial load due to temperature decrease

If the temperature decreases after the cementing job due to the circulation of cold fluid in the well, a tensile force is caused, changing the axial load. Three scenarios have been calculated for the surface, anchor and production casing strings. Results are listed in Table 13.

TABLE 13: Axial force due to temperature decrease

	T_1 (°C)	T_2 (°C)	Compressive force Fc (kN)	Resultant force Fr (Kn)	Min. yield strength (kN)	Calculated	Min. design factor
Surface casing (20″)	30	95	-3008	3105	6581.7	2.12	1.2
	35	95	-2777	2873	6581.7	2.29	1.2
	40	95	-2545	2642	6581.7	2.49	1.2
Anchor casing (13⅜″)	**T_1 (°C)**	**T_2 (°C)**	**Compressive force Fc (kN)**	**Resultant force Fr (Kn)**	**Min. yield strength (kN)**	**Calculated**	**Min. design factor**
	30	127	-3243	3172	6912.3	2.18	1.2
	35	127	-3076	3004	6912.3	2.30	1.2
	40	127	-2909	2837	6912.3	2.44	1.2
Production casing (9⅝″)	**T_1 (°C)**	**T_2 (°C)**	**Compressive force Fc (kN)**	**Resultant force Fr (Kn)**	**Min. yield strength (kN)**	**Calculated**	**Min. design factor**
	30	183	-3570	3385	4824.6	1.43	1.2
	35	183	-3453	3268	4824.6	1.48	1.2
	40	183	-3337	3151	4824.6	1.53	1.2

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

Due to the lifting force by the fluid in the well, a strain at the top of the anchor casing may be generated. The well is assumed to be full of steam with a maximum wellhead pressure of 9.7 MPa and with an ANSI class 900 for safety due to the extremely saline fluid that may come up from the borehole to the surface. Table 14 lists the results calculated.

TABLE 14: Tensile force due to lifting force by the fluid on the anchor casing

Casing grade L-80	Casing weight (lb/ft)	Tensile force at top, Fw (kN)	Min. tensile strength (kN)	Calculated design factor	Min. design factor
Anchor casing (13⅜″)	68	756	6912.3	9.14	1.8

8.5 Thermal expansion of the anchor casing into the wellhead

It is likely that the production casing rises into the wellhead during the production phase of the well. Therefore, a lifting load could act on the anchor casing during production. Results are listed in Table 15.

TABLE 15: Thermal load expansion (wellhead)

Casing grade L-80	Casing weight (lb/ft)	Anchor casing tensile strength (kN)	Rising casing compressive strength, Fw (kN)	Calculated design factor	Min. design factor	Comments
Anchor casing (13⅜″)	61.0 68.0	6216.3 6912.3	756 756	8.2 9.14	1.4 1.4	**Suitable**

8.6 Helical and buckling for liner casing

The un-cemented liners are subject to axial self-weight and helical buckling. The results listed in Table 16 consider the temperature reduction factor for different grades. Note that **Ri** is the temperature reduction factor for different grades and **Rj** is the connection efficiency in compression.

TABLE 16: The helical buckling of the liner casing (uncemented)

Casing diameter and grade	Compressive stress (MPa)	Ri	Rj	Minimum yield strength (MPa)	Calculated design factor	Min. design factor	Comments
7″ K-55 (26 lb/ft)	382.28	0.7	1	379	0.69	1	**Not suitable**
7″ K-55 (46 lb(ft)	642.11	0.7	1	379	0.41	1	**Not suitable**
7″ L-80 (26 lb/ft)	382.28	0.81	1	551	1.17	1	**Suitable**

8.7 Internal differential pressure at the casing shoes

The maximum internal differential pressure of the casing section at the casing shoe for the surface, anchor and production casings are shown in Table 17.

TABLE 17: Internal differential pressure at the casing shoes

Casing diameter	Lz (m)	Lf (m)	Differential internal pressure (MPa)	Internal yield pressure (MPa)	Calculated design factor	Min. design factor
20″ K-55	250	230	2.16	14.5	6.71	1.5
13⅜″ L-80	450	430	7.55	34.6	4.58	1.5
9⅝″ L-80	800	780	6.47	47.3	7.31	1.5

8.8 External differential pressure at the casing shoes

The maximum external differential pressure of the casing section at the casing shoe for the surface, anchor and production casing are shown in Table 18.

TABLE 18: External differential pressure at the casing shoes

Casing diameter	Lz (m)	Lf (m)	Differential internal pressure (MPa)	Internal yield pressure (MPa)	Calculated design factor	Min. design factor
20″ K-55	250	230	1.96	14.5	7.39	1.5
13⅜″ L-80	450	430	3.53	34.6	9.80	1.5
9⅝″ L-80	800	780	6.27	47.3	7.54	1.5

8.9 External differential pressure during production operation

The maximum external differential pressure arises near the casing shoe. The maximum pressure downhole is 9.7 MPa and the design factors are listed in Table 19 assuming full steam from the bottom of the borehole to the surface.

TABLE 19: External pressure collapse during production operation

Casing diameter	Lz (m)	Differential external pressure (MPa)	Pipe collapse pressure	Calculated design factor	Min. design factor
9⅝″ K-55	800	9.7	26.8	2.76	1.2
9⅝″ L-80	800	9.7	32.8	3.38	1.2

9. WELLHEAD SELECTION

According to the *African Union Code of Practice for Geothermal Drilling* (African Union's Regional Geothermal Coordination Unit, 2016), the selection of the wellhead needs to be given great consideration to ensure safety. Figure 18 shows a typical wellhead and Figure 19 shows a diagram on how to select a proper wellhead based on the maximum pressure obtained or assumed in the area that is going to be drilled. The maximum wellhead pressure is 9.7 MPa (97 bar) at a temperature of 310°C, that results in wellhead selection of an ANSI 900 as shown in Figure 19.

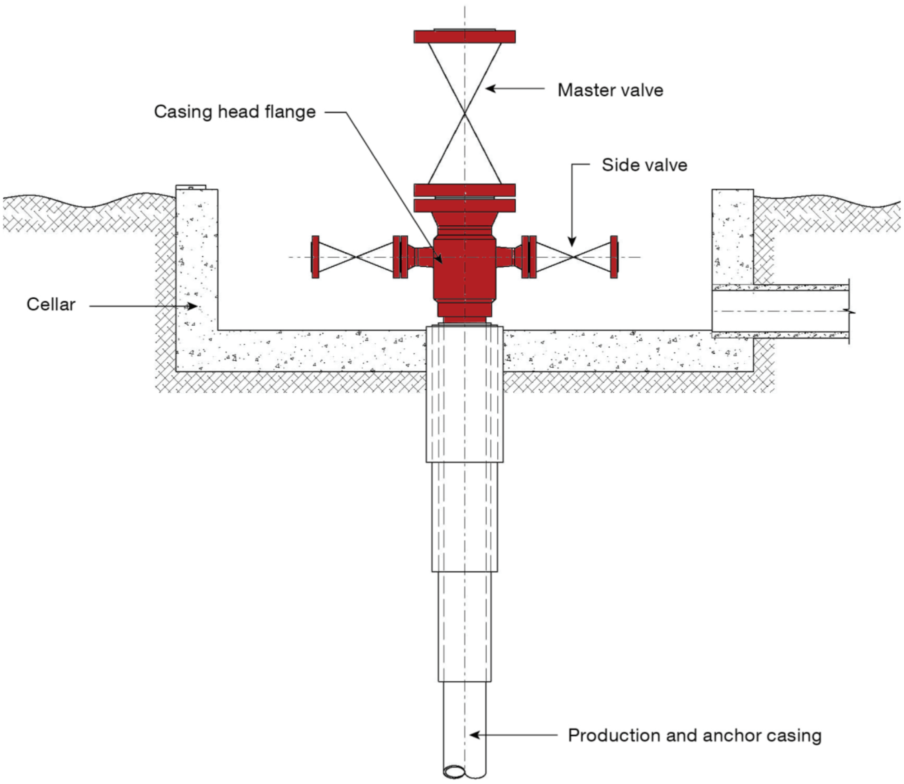


FIGURE 18: Typical permanent wellhead
(African Union's Regional Geothermal Coordination Unit, 2016)

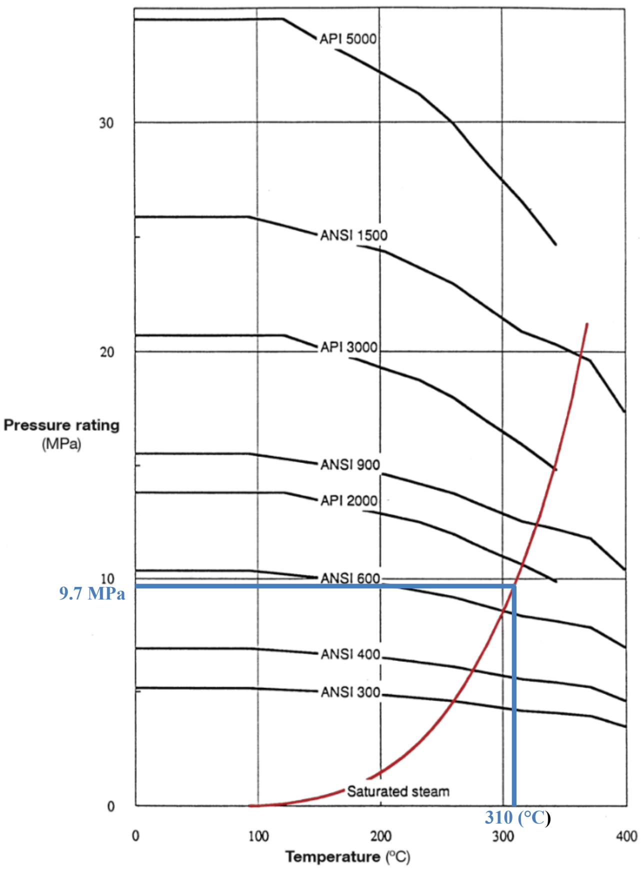


FIGURE 19: Wellhead working pressure of 9.7 MPa at 310°C
(African Union's Regional Geothermal Coordination Unit, 2016)

10. NOVEL TECHNOLOGY FOR REDUCING THERMAL EXPANSION IN CASING

For a cost effective and long life of the well and to avoid failure due to thermal expansion, a new patented technology was invented and field tested for the first time in the summer of 2020 by ÍSOR, called Flexible coupling (FC), replacing conventional couplings of casing joints of the production casing (Figure 20). The objective of this technology is to reduce thermal stress on the casing and thereby reduce the risk of failure and collapse, which extends the lifetime of the well and increases well productivity. Flexible coupling is designed for high enthalpy wells that have temperatures above 200°C for 13⅜″ and 9⅝″ casings (Thorbjörnsson and Kaldal, 2021).

Coupling function:

- The casing is run into the hole.
- The coupling remains in the open position during casing installation.
- The gap L_T is fixed for design temperatures in each case.
- When the casing warms up, it expands and the flexible coupling closes without generating permanent deformations (plastic strain) due to the thermal load.

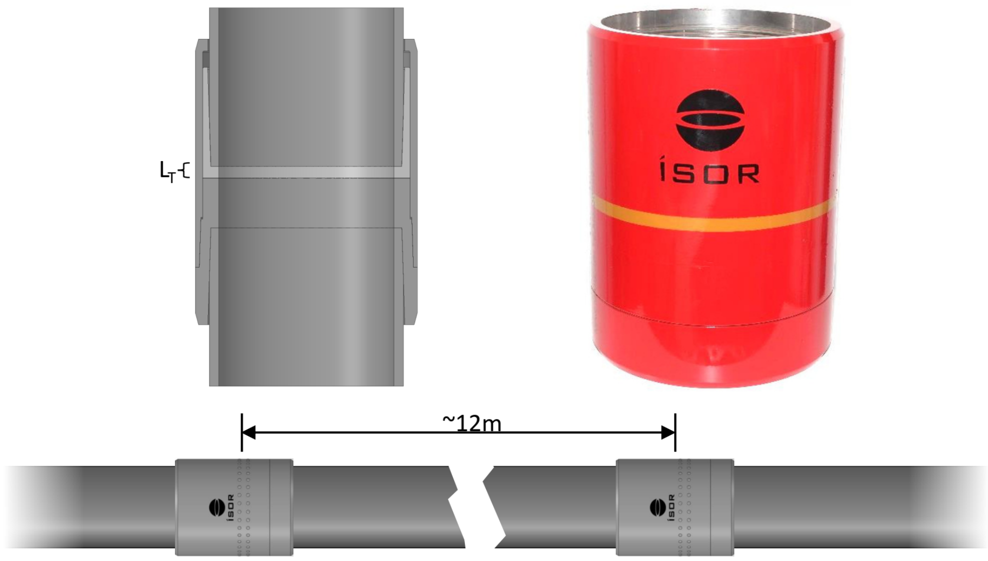


FIGURE 20: Flexible coupling apparatus (FC) (Skúlason Kaldal, 2021)

11. PRELIMINARY DRILLING PROGRAM

A drilling program provides a clear guideline on the best and safest practices of drilling a geothermal well. However, modifications to the program can be made during the drilling process in accordance to prevailing conditions. The following drilling program has been obtained by incorporating previous drilling programs applied in the Asal area and by taking into account the anticipated hazard in this area. The following guidelines are based on experiences in the Asal area.

11.1 26” hole section

Drill the 26″ hole to 250 m MD and set the 20″ casing. It is recommended to use cement slurries of two densities (lead and tail) for the 20″ casing and the 13⅜″ casing cement job.

Drilling objectives:

- Drill 26″ section from surface shoe to 250 m MD.
- Set 20″ casing to bottom and case off shallow unconsolidated formations and loss zones.
- Drill to sufficient casing depth to install the BOPE.
- Stabilize the wellbore.
- Log lessons learned daily.

Anticipated hazards:

- Partial to total circulation loss.
- Wellbore stability and hole cleaning problems.

Preparation:

- Prepare the spud mud in the active and reserve systems and the pre-hydrated gel in the pre-hydrated tank. Mud viscosity must be between 50 and 55 cP.
- Rig up and conduct a function test of the continuous circulating system, conduct training of the rig crew.
- Ensure pit volume totalizer (PVT) system, fill-up and drain valves, backside flow meter, and trip tank level indicator are operational.
- Ensure that all gas sensors are operational.
- Ensure that 20″ casing and accessories, cementing materials, 21¼″ x 20″ casing head and side outlet valves, and BOPE stack items are available and functional.
- Use seal lock spacer prior to pumping cement slurries to seal off circulation loss zones.

11.2 20″ Drilling fluid properties

The basic drilling fluid properties are shown in Tables 20 to 22. The drilling fluid properties may be modified if deemed necessary during drilling.

TABLE 20: Fluid properties for polymer water (severe to total losses)

Fluid parameters (spud)	**Unit**	**Min**	**Max**
Mud weight	00000	8.33	8.9
pH		9	11
API fluid loss (filtrate)	cc/30 sec	N/A	
Plastic viscosity	cP	ALAP	
Yield point	lb/100 ft^2	20	>20+

TABLE 21: Fluid properties for gel polymer mud (full returns)

Fluid parameters (spud)	**Unit**	**Min**	**Max**
Mud weight	ppg	8.4	8.9
pH		9	10.5
API fluid loss (filtrate)	cc/30 sec	15-20	
Plastic viscosity	cP	<15	
Yield point	lb/100 ft^2	30	45

TABLE 22: Fluid properties for high-vis pill

Fluid parameters (hi-vis)	Unit	Min	Max
Mud weight	ppg	Active mud	
pH		9	10.5
API fluid loss (filtrate)	cc/30 sec	15-20	
Plastic viscosity	cP	<20	
Yield point	lb/100 ft^2	>50	

11.3 Bit and hydraulic program

Recommended bit types and basic drilling parameters are listed in Table 23.

1) Weight on bit (WOB): Typically, the WOB for drilling at a depth of 250 meters with a 26-inch bit could range from 8,000 to 28,000 pounds (4 to 14 tons), depending on the formation characteristics and drilling objectives.
2) Surface rotary speed (RPM): The RPM of the drill string at the surface may vary based on factors such as bit type, formation characteristics, and drilling objectives. It could range from 50 to 80 RPM.
3) Jet size: The size of the jets in the drill bit, which influences the flow rate of drilling fluid through the bit, could be specified in thirty-seconds of an inch (/32). For example, a jet size of 3x24, 1x28 (CJ) with a total flow area (TFA) of 1.926 square inches may be suitable.
4) Flow rate: The flow rate of drilling fluid being pumped through the drill string is typically measured in gallons per minute (GPM). It could range from 600 to 1,200 GPM.

These parameters are general guidelines and should be adjusted based on real-time drilling conditions, formation characteristics, and equipment capabilities to ensure optimal drilling performance and wellbore stability. Additionally, consulting with experienced drilling engineers and geologists is recommended for specific well planning and optimization.

TABLE 23: Basic drilling parameters for 26" section

Depth (m)	Bit size (in)	IADC code	WOB (klbs)	Surface RPM	Jet size (/32)	Flow (GPM)
250	26	415 (main) 425 (backup)	8K-28K pounds (4-14 tons)	50-80	3x24, 1x28 (CJ) TFA: 1.926 in^2	600-1,200

11.4 Planned BHA

The proposed 26″ BHA is detailed in Table 24.

1) Tricone bit: This refers to the drilling bit used in rotary drilling operations. It has an outer diameter (OD) of 3.5 inches and an inner diameter (ID) of 26 inches. The weight is 208.78 pounds per foot (ppf). The upper connection is a 7-5/8" regular connection, and it has a length of 0.6 meters. The total length of the tricone bit is also 0.6 meters.
2) Mud motor: This is a downhole motor used to provide additional power and torque to the drill bit. It has an OD of 9.5 inches and an ID of 25.875 inches. The weight is 179.08 ppf. The upper connection is a 7-5/8" regular connection, and it has a length of 8.6 meters. The total length of the mud motor is 9.2 meters.

3) Float sub: This is a tool used to control the buoyancy of the drill string. It has an OD of 9.5 inches and an ID of 3 inches. The weight is 217.48 ppf. The upper connection is a 7-5/8" regular connection, and it has a length of 1.0 meter. The total length of the float sub is 10.2 meters.
4) String stabilizer: This is a stabilizing tool used to minimize vibrations and ensure straight drilling. It has an OD of 9.5 inches and an ID of 3 inches. The gauge size is 27-3/4 inches. The weight is 217.48 ppf. The upper connection is a 7-5/8" regular connection, and it has a length of 1.8 meters. The total length of the string stabilizer is 12.0 meters.
5) Shock sub: This is a tool used to absorb shock and vibration during drilling operations. It has an OD of 9.5 inches and an ID of 2.75 inches. The weight is 221.32 ppf. The upper connection is a 7-5/8" regular connection, and it has a length of 4.0 meters. The total length of the shock sub is 16.6 meters.
6) DC (3 joints): This refers to drill collars, which add weight to the drill string to help maintain weight on the drill bit. Three joints of drill collars are listed here. Each joint has an OD of 9.5 inches and an ID of 3.25 inches. The weight is 212.80 ppf. The upper connection is a 7-5/8" regular connection, and each joint has a length of 27.4 meters. The total length of the three joints of drill collars is 43.4 meters.

TABLE 24: BHA for 26" section

Item	Description	Body OD (in)	ID (in)	Gauge (in)	Weight (ppf)	Upper conn.	Length (m)	Total length (m)
1	Tricone bit		3.5	26	208.78	P 7-5/8" regular	0.6	0.6
2	Mud motor	9.5		25.875	179.08	B 7-5/8" REG	8.6	9.2
3	Float sub	9.5	3		217.48	B 7-5/8" REG	1.0	10.2
4	String stabilizer	9.5	3	27-3/4	217.48	B 7-5/8" REG	1.8	12.0
5	Shock sub	9.5	2.75		221.32	B 7-5/8" REG	4.0	16.6
6	DC (3 joints)	9.5	3.25		212.80	B 7-5/8" REG	27.4	43.4

11.5 20″ casing running procedure and cementing

The objectives of the 20″ casing running procedure and cementing include covering troublesome zones, ensuring pressure integrity for BOPE installation, and obtaining a uniform cement bond to the surface behind the casing, as outlined in Table 25. These objectives serve as guiding principles for the execution of the procedure, aiming to achieve stability and integrity in the wellbore.

TABLE 25: Casing specifications for running and cementing procedure

Top (ft)	Bottom (m)	Length (m)	Description
Surface	250	250	20″ 94 ppf, k-55, BTC

11.6 20” casing running operation

1) Hold pre-job safety meeting and discuss the 20″ casing running procedure.

   a) Be prepared to POOH with 20″ casing if the casing cannot land to bottom or if a long rat hole is observed.
2) Observe and ensure that the hole is static.
3) Rig up 20″ handling tools. If used, ensure the safety pin on the single joint elevator is latched properly. Alternatively, weld lifting ears on each casing prior to them being run in the hole.
4) Flow-check and ensure that the well is static.
5) Continue pumping mud at the back side while RIH 20″ casing, if the fluid level drops.
6) Run the following pre-assembled components
   a) 20″ double valve stab-in float shoe.
   b) Prepare the 20″, 94 ppf, and BTC backup cementing swage.
   c) Visually inspect the float valves prior to RIH.
7) Run the rest of the 20″ casing string.
   d) Ensure that each connection is made up properly according to the BTC make up procedure.
   e) Watch the shakers for returns while running the casing. Notify the DSV immediately if the returns start to diminish or increase.
   f) Fill the casing string on each connection after passing the estimated depth of the water table.
8) Run casing to planned depth (within ± 2 m of section TD). Record pick up and slack off weights. Set the elevator on wooden blocks. Rig down casing running equipment and rig up the "C" plate on top of 20″ casing collar. Rig up top drive link bails and install the 5″ DP elevator.
9) Pick up the stab-in stand and install two (2) drill pipe centralizers. RIH with 5″ DP to the top of the float shoe. Break circulation and fill 20″ casing before stabbing into 20″ float shoe. Stab into the float collar. Slack off with 2.5 tons (±5,000 lb) and consider chaining the pipe string down during cementing if deemed necessary.
10) Circulate to condition the mud (min 1.5x annular volume until minimal cuttings, temperature stabilizes, and the well is cool). Check for stab-in adapter leaks.

11.7 20″ cementing operation

The main goal of cementing the 20″ casings is to achieve a full cement column back to surface during the primary cement job without the need to do multiple costly and time-consuming top-out jobs. It is strongly recommended to use the two densities slurry design to cement the 20″ casing using 13.5 ppg lead cement slurry and 15.8 ppg tail cement slurry (10 m). Top-up cement jobs use a minimum of 15.8 pound per gallon neat cement slurry. If ODDEG decides to not use a shoe track, then the cement inside the drill pipe must be displaced by at least 2 barrels.

Lab test results for cementing casings should be provided by the cementing company for evaluation and approval, as well as available float equipment, centralizer programs and cementing programs.

11.8 17½″ hole section

Drill the 17½″ hole to 450 m MD and set the 13⅜″ casing.

Drilling objectives:

- Drill the cement inside the 20″ shoe track and the new hole from the 20″ casing shoe depth to section TD (13⅜″ casing shoe depth).
- Set 13⅜″ casing to bottom and case off unconsolidated formations, gas zones, and loss zones.
- Log lessons learned daily.

Anticipated hazards:

- High potential for circulation loss in fractured zones.
- Potential for high bottom-hole temperature and possibility of steam or other gas kicks.

Preparation:

- Mix the drilling fluid and fill the active and reserve systems and pre-hydrated gel on the pre-hydrated tank.
- Ensure that the PVT system, backside flow meter, and trip tank indicator are operational.
- Ensure that the gas sensors are operational.
- Ensure that the 13⅜″ casing head and side outlet valves, master valve, and 13⅜″ casing, float equipment and other casing accessories are available.

11.9 17½″ drilling fluid properties

A mud system with the basic properties shown in Tables 26-28 is recommended. If hole instability issues due to clays are encountered, an inhibitive mud system will be required.

TABLE 26: Drilling fluid properties for 17½″ section (full returns)

Fluid parameters	Unit	Min	Max
Mud weight	ppg	8.4	8.9
pH	N/A	9	10.5
API fluid loss (filtrate)	cc/30 sec	<8	
Plastic viscosity	cP	<15	
Yield point	lb/100 ft^2	20	35
Solids	%	<5	

TABLE 27: Drilling fluid properties for 17½″ section (partial or total losses)

Fluid parameters	Unit	Min	Max
Mud weight	ppg	8.33	8.4
pH	N/A	9	10.5
API fluid loss (filtrate)	cc/30 sec	N/A	
Plastic viscosity	cP	ALAP	
Yield point	lb/100 ft^2	20	20+
Solids	%	<5	

TABLE 28: Drilling fluid properties for high-vis pill

Fluid parameters (hi-vis)	Unit	Min	Max
Mud weight	ppg	Active mud	
pH	n/a	9	10.5
API fluid loss (filtrate)	cc/30 sec	<8	
Plastic viscosity	cP	<15	
Yield point	lb/100 ft^2	>50	

11.10 17½″ bit and hydraulic program

Table 29 provides valuable insights into the recommended bit types and basic drilling parameters essential for the operation's success.

For the 17½″ bit size, the IADC code indicates the main and backup options available for selection. The Weight on Bit (WOB) ranges from 10 to 40 klbs (5 to 20 tons), ensuring optimal drilling performance while maintaining stability. Surface revolutions per minute (RPM) are suggested to be maintained between 60 and 80 to achieve efficient cutting action and borehole cleanliness.

Jet sizes, represented in 32nds of an inch, play a crucial role in determining the rate of fluid delivery to the drill bit. In this case, a configuration of 3x20 and 1x18 (CJ) is recommended, ensuring adequate fluid flow for effective drilling operations. The total flow area (TFA) is specified at 1.169 square inches, providing further insight into the fluid dynamics at the drilling interface.

Lastly, the recommended gallons per minute (GPM) range from 750 to 1,200, indicating the required fluid circulation rates to carry cuttings away from the bit and maintain wellbore stability.

TABLE 29: Drilling parameters and bit types

Bit size (in)	IADC code	WOB (klbs)	Surface RPM	Jet size (32nds)	GPM
17½″	515 (main) 445 (backup)	10-40 (5-20 tons)	60-80	3x20, 1x18 (CJ) TFA: 1.169 in^2	750-1,200

11.11 17½″ planned BHA

Table 30 shows the components of the proposed bottom hole assembly.

Tricone bit: This component features an outer diameter (OD) of 6.75 inches and an inner diameter (ID) of 4 inches. It's designed for drilling with a weight of 17.5 pounds per foot (ppf). The upper connection is made through a P 7-5/8" REG connection. Its total length is 0.4 meters.

Mud motor with 1.15 deg bend: This mud motor has an OD of 9.5 inches and an ID of 6.135 inches. It weighs 17.25 ppf and is equipped with a sleeve stab. The upper connection is a B 7-5/8" REG, and its length is 9.6 meters.

Float sub: The float sub has a body OD of 9.5 inches and an ID of 2.875 inches. Its upper connection is a B 7-5/8" REG, and its length is 10.3 meters.

Shock sub: With a body OD of 9.5 inches and an ID of 3 inches, the shock sub is designed to absorb shock during drilling operations. It connects through a B 7-5/8" REG and has a length of 14.4 meters.

String stabilizer: This stabilizer has a body OD of 9.6 inches and an ID of 3 inches. It weighs 17.25 ppf and connects through a B 7-5/8" REG. Its length is 16.7 meters.

NMDC: The NMDC has an OD of 9.5 inches and an ID of 3.5 inches. It connects through a B 7-5/8" REG and has a length of 25.4 meters.

EM index sub (with PWD): This sub has an OD of 9.5 inches and an ID of 3.25 inches. It connects through a B 7-5/8" REG and has a length of 26.1 meters.

EM antenna sub: Featuring an OD of 9.5 inches and an ID of 3.25 inches, the EM antenna sub connects through a B 7-5/8" REG. Its length is 27.0 meters.

XO: The XO component has an OD of 9.6 inches and an ID of 3.25 inches. It connects through a B 6-5/8" REG and has a length of 27.9 meters.

TABLE 30: Proposed 17½″ BHA

Item #	Description	Body OD (in)	ID (in)	Gauge (in)	Weight (ppf)	Upper conn.	Length (m)	Total length (m)
1	Tricone bit	6.75	4	17.5	79.13	P 7-5/8" REG	0.4	0.4
2	Mud motor w/ 1.15 deg bend (Lobe 6/7, 5.0 stg) w/ sleeve	9.5	6.135	17.25	179.08	B 7-5/8" REG	9.2	9.6
3	Float sub	9.5	2.875		219.44	B 7-5/8" REG	0.7	10.3
4	Shock sub	9.5	3		217.48	B 7-5/8" REG	4.1	14.4
5	String stabilizer	9.6	3	17.25	222.59	B 7-5/8" REG	2.4	16.7
6	NMDC	9.5	3.5		208.78	B 7-5/8" REG	8.7	25.4
7	EM index sub (w/ PWD)	9.5	3.25		213.29	B 7-5/8" REG	0.6	26.1
8	EM antenna sub	9.5	3.25		213.29	B 7-5/8" REG	0.9	27.0
9	XO	9.6	3.25		213.29	B 6-5/8" REG	1.0	27.9
10	DC	8	2.813		149.8	B 6-5/8" REG	9.1	37.1
11	Jar	8	2.75		132.58	B 6-5/8" REG	9.5	46.6
12	DC (4 joints)	8	2.813		149.8	B 6-5/8" REG	36.6	83.1
13	XO	6.5	2.875		90.96	B 4-1/2" IF	1.0	84.1
14	HWDP (12 joints)	5	3		49.3	B 4-1/2" IF	109.7	193.9
							Total:	**193.9**

11.12 13⅜″ casing running procedure and cementing procedure

Table 31 provides specifications and details regarding the 13⅜″ casing running procedure and cementing operation. It outlines the objectives of the operation, including the installation of the 13⅝″ permanent wellhead and the Blowout Preventer (BOPE), maximizing cement coverage to address potential circulation loss zones, and isolating unconsolidated formations and thief zones. The table also presents the top and bottom depths of the casing, the length of the casing string, and its description, including parameters such as weight per foot (ppf), casing material grade (K55-L80), connection type (BTC), and the method of cementing. The objective is to achieve a uniform and impermeable cement bond behind the 13⅜″ casing to ensure well integrity and stability."

TABLE 31: Specifications for 13⅜″ casing and cementing

Top (m)	Bottom (m)	Length (m)	Description
0	450	450	68 ppf, K55-L80, BTC, cemented casing back to surface

11.13 13⅜″ casing running operation and cementing

1) Hold pre-job safety meeting and discuss the 13⅜″ casing running procedure.
   a) Be prepared to POOH 13⅜″ casing if it cannot be run to bottom or if a long rat hole is observed.

2) Observe and ensure that the hole is static.
3) Rig up 13⅜″ handling tools. Calibrate the top drive signal with the torque chart (if applicable). Ensure the safety pin on single joint elevator is latched properly.
4) Flow-check and ensure that the well is static.
5) Continue pumping mud at the back side while running the 13⅜″ casing if the fluid level drops.
6) Run the 13⅜″ casing as follows:
    a) Pre-assembled components 13⅜″ float shoe, 1 joints of 13⅜″ casing, 13⅜″ stab-in latch-on float collar (SOW).
    b) Bakerlok the shoe track assembly.
    c) Visually inspect the float valves prior to RIH.
7) Run the rest of the 13⅜″ casing string.
    a) Ensure that the connections are made up properly. Make up joints to the optimum torque. Refer to the service provider casing running program for make-up procedures and torque details.
    b) Casing running crew should ensure that the torque chart profile of every joint is recorded on the torque chart. Torque charts need to be submitted to DSV as part of the job report.
    c) Show the location of all centralizers (if required) on the signed casing tally.
    d) Watch the shakers for returns while running the casing. Notify the DSV immediately if the returns start to diminish.
    e) If high temperature was encountered during drilling and there is no loss of circulation, consider stopping and circulating to cool down the hole every 15 m of casing run in the hole.
    f) Wash down every joint of casing run. Use the compatible and clean mud for this purpose.
8) Cement the 13⅜″ casing with the recommended slurry design (it is recommended to use at least 100% excess volume of the open hole section).
    a) Break circulation to ensure there is no restriction.
    b) Use seal lock spacer (or equivalent) to seal off losses.
    c) Proceed with cementing job as specified in the cementing program provided by the rig manager and approved by ODDEG.
    d) Drop the drill pipe dart and displace the cement with mud with cement pump from the displacement tanks on the pump unit. Record displacement volume when drill pipe dart engages with the liner wiper plug.
    e) Continue displacement to the float collar, bump plug with 500 psi. DO NOT OVERDISPLACE MORE THAN HALF OF SHOE TRACK.
    f) Check floats.
9) POOH with 5″ inner string and wait on cement.
10) Nipple down 21¼″ BOPE. Cut 20″ casing at 0.5 m below ground level and lay down 21¼″ temporary wellhead.
11) Make final cut on the 13⅜″ so that top of 13⅜″ permanent casing head flange (CHF) is at ground level.
12) Install permanent 12″ master valve, class 600 RTJ flanged ends.
13) Nipple up 13⅝″ BOPE on top of 12″ master valve.
    a) Low pressure test to 250 psi and high-pressure test to 1,000 psi all BOPE and wellhead valves, against 13⅜″ casing. Hold each for 15 min.

11.14 12¼″ hole section

Drill the 12¼″ hole to 800 m MD and set the 9⅝″ casing.

Drilling objectives:

- Drill the cement inside the 20″ shoe track and new hole from the 13⅜″ casing shoe depth to section TD (9⅝″casing shoe depth).
- Set 9⅝″ casing to bottom and case off unconsolidated formations, gas zones, and loss zones.
- Log lessons learned daily.

Anticipated hazards:

- High potential for circulation loss in fractured zones.
- Potential for high bottom-hole temperature and possibility of steam or other gas kicks.

Preparation:

- Mix the drilling fluid and fill the active and reserve systems and pre-hydrated gel on the pre-hydrated tank.
- Ensure that the PVT system, backside flow meter, and trip tank indicator are operational.
- Ensure that the gas sensors are operational.
- Ensure that the 9⅝″ casing head and side outlet valves, master valve, and 9⅝″ casing, float equipment and other casing accessories are available.

11.15 12¼″ drilling fluid properties

The provided tables detail the recommended drilling fluid properties for the 12¼″ section under various operational conditions. Table 32 outlines parameters for situations with full returns, emphasizing a mud weight range of 8.4 to 8.9 ppg and a yield point between 20 and 35 lb/100 ft^2 to maintain fluid stability. Table 33 addresses scenarios of partial or total losses, adjusting the mud weight range slightly lower and emphasizing fluid loss control. Particularly, the plastic viscosity is indicated as "ALAP," suggesting flexibility to minimize viscosity. Table 34 introduces a specialized high-viscosity pill with stringent parameters, including a minimum yield point exceeding 50 lb/100 ft^2, aimed at providing effective wellbore stabilization. These tables collectively offer comprehensive guidance for optimizing drilling fluid performance and ensuring wellbore integrity in the 12¼″ section under varied drilling conditions.

TABLE 32: Drilling fluid properties for 12¼″ section (full returns)

Fluid parameters	Unit	Min	Max
Mud weight	ppg	8.4	8.9
pH	n/a	9	10.5
API fluid loss (filtrate)	cc/30 sec	<8	
Plastic viscosity	cP	<15	
Yield point	lb/100 ft^2	20	35
Solids	%	<5	

TABLE 33: Drilling fluid properties for 12¼″ section (partial or total losses)

Fluid parameters	Unit	Min	Max
Mud weight	ppg	8.33	8.4
pH	n/a	9	10.5
API fluid loss (filtrate)	cc/30 sec	NA	
Plastic viscosity	cP	ALAP	
Yield point	lb/100 ft^2	20	20+
Solids	%	<5	

TABLE 34: Drilling fluid properties for 12¼″ section high-vis pill

Fluid parameters (hi-vis)	Unit	Min	Max
Mud weight	ppg	Active Mud	
pH	n/a	9	10.5
API fluid loss (filtrate)	cc/30 sec	<8	
Plastic viscosity	cP	<15	
Yield point	lb/100 ft^2	>50	

11.16 12¼″ bit and hydraulic program

Table 35 presents the recommended bit types and basic drilling parameters for the 12¼″ section. The table includes key parameters such as bit size, IADC code, weight on bit (WOB), surface revolutions per minute (RPM), jet size, and gallons per minute (GPM). For a 12¼″ bit, the recommended WOB ranges from 10 to 40 klbs (5 to 20 tons), with surface RPM between 60 and 80. The jet size is specified as 3x20 and 1x18 (CJ), indicating three jets of size 20 and one of size 18. Additionally, the table provides a total flow area (TFA) of 1.169 square inches and recommends a flow rate of 750 to 1,200 gallons per minute. This information serves as a guide for selecting appropriate drilling parameters to optimize drilling performance in the 12¼″ section.

TABLE 35: 12¼″ bit and hydraulic program

Bit size (in)	IADC code	WOB (klbs)	Surface RPM	Jet size (32nd)	GPM
12¼″	515 (main) 445 (backup)	10-40 (5-20 tons)	60-80	3x20, 1x18 (CJ) TFA: 1.169 in^2	750-1,200

11.17 12¼″ planned BHA

The proposed 12¼″ Bottom Hole Assembly (BHA), as outlined in Table 36, comprises essential components crucial for efficient drilling operations. It includes a tricone bit for drilling, a mud motor for powering the bit, and various subs and stabilizers to maintain wellbore stability. Non-magnetic drill collars and electromagnetic components aid in wellbore surveying and data acquisition. Additionally, drill collars and heavy-weight drill pipe provide weight and stiffness to the BHA for effective drilling. This comprehensive assembly ensures optimal drilling performance and wellbore integrity during operations.

11.18 9⅝″ casing running procedure and cementing procedure

The 9⅝″ casing running and cementing procedure aims to achieve several objectives crucial for wellbore integrity and operational success. First and foremost, it involves the installation of 9⅝″ casing, accompanied by cementing operations to secure the casing in place and create a reliable seal against potential fluid migration and formation instability. Additionally, the procedure focuses on maximizing cement coverage across zones prone to circulation losses, such as unconsolidated formations and thief zones, to mitigate any risks of fluid migration or wellbore collapse. Furthermore, the objective includes casing off these formations and zones to ensure wellbore stability and integrity. Ultimately, the goal is to attain a uniform and impermeable cement bond to the surface behind the 9⅝″ casing, providing a secure foundation for subsequent wellbore operations.

TABLE 36: Proposed 12¼″ BHA

Item #	Description	Body OD (in)	ID (in)	Gauge (in)	Weight (ppf)	Upper conn.	Length (m)	Total length (m)
1	Tricone bit	6.75	4	17.5	79.13	P 7-5/8" REG	0.4	0.4
2	Mud motor w/ 1.15 deg bend (Lobe 6/7, 5.0 stg) w/ sleeve stab	9.5	6.135	17.25	179.08	B 7-5/8" REG	9.2	9.6
3	Float sub	9.5	2.875		219.44	B 7-5/8" REG	0.7	10.3
4	Shock sub	9.5	3		217.48	B 7-5/8" REG	4.1	14.4
5	String stabilizer	9.6	3	17.25	222.59	B 7-5/8" REG	2.4	16.7
6	NMDC	9.5	3.5		208.78	B 7-5/8" REG	8.7	25.4
7	EM index sub (w/ PWD)	9.5	3.25		213.29	B 7-5/8" REG	0.6	26.1
8	EM antenna sub	9.5	3.25		213.29	B 7-5/8" REG	0.9	27.0
9	XO	9.6	3.25		213.29	B 6-5/8" REG	1.0	27.9
10	DC	8	2.813		149.8	B 6-5/8" REG	9.1	37.1
11	Jar	8	2.75		132.58	B 6-5/8" REG	9.5	46.6
12	DC (4 joints)	8	2.813		149.8	B 6-5/8" REG	36.6	83.1
13	XO	6.5	2.875		90.96	B 4-1/2" IF	1.0	84.1
14	HWDP (12 joints)	5	3		49.3	B 4-1/2" IF	109.7	193.9
							Total:	**193.9**

Objectives (Table 37):

- Run and cement 9⅝″ casing and install the 9⅝″ permanent wellhead and the BOPE.
- Maximize cement coverage across the potential circulation loss zones in the 9⅝″ casing.
- Case off unconsolidated formations and thief zones.
- Obtain a uniform and impermeable cement bond to surface behind the 9⅝″ casing.

TABLE 37: 9⅝″ Casing running and cementing

Top (m)	Bottom (m)	Length (m)	Description
0	800	800	68 ppf, L80, BTC, cemented casing back to surface

11.19 9⅝″ casing running operation and cementing

1) Hold pre-job safety meeting and discuss the 9⅝″ casing running procedure.
2) Observe and ensure that the hole is static.
3) Rig up 9⅝″ handling tools. Calibrate the top drive signal with the torque chart (if applicable). Ensure the safety pin on single joint elevator is latched properly.
4) Flow-check and ensure that the well is static.
5) Continue pumping mud at the back side while running the 9⅝″ casing if the fluid level drops.
6) Run the 9⅝″ casing as follows:
   a) Pre-assembled components 9⅝″ float shoe, 1 joints of 9⅝″ casing, 9⅝″ stab-in latch-on float collar (SOW).

    b) Visually inspect the float valves prior to RIH.
7) Run the rest of the 9⅝″ casing string.
    a) Ensure that the connections are made up properly. Make up joints to the optimum torque. Refer to the service provider casing running program for make-up procedures and torque details.
    b) Casing running crew should ensure that the torque chart profile of every joint is recorded on the torque chart.
    c) Show the location of all centralizers (if required) on the signed casing tally.
    d) Watch the shakers for returns while running the casing. Notify the DSV immediately if the returns start to diminish.
    e) If high temperature was encountered during drilling and there is no loss of circulation, consider stopping and circulating to cool down the hole every 15 m of casing run in the hole.
    f) Wash down every joint of casing run. Use the compatible and clean mud for this purpose.
8) Cement the 9⅝″ casing with the recommended slurry design (it is recommended to use at least 100% excess volume of the open hole section).
    a) Break circulation to ensure there is no restriction.
    b) Use seal lock spacer (or equivalent) to seal off losses.
    c) Drop the drill pipe dart and displace the cement with mud with cement pump from the displacement tanks on the pump unit. Record displacement volume when drill pipe dart engages with the liner wiper plug.
    d) Check floats.
9) POOH with 5″ inner string and wait on cement.
10) Nipple down 21¼″ BOPE. Cut 20″ casing at 0.5 m below ground level and lay down 21¼″ temporary wellhead.
11) Install permanent 12″ master valve, class 900 RTJ flanged ends.
    a) Low pressure test to 250 psi and high-pressure test to 1,000 psi all BOPE and wellhead valves, against 9⅝″ casing. Hold each for 15 min.

11.20 8⅜″ hole section (500 m perforated)

Drill 8⅜″ hole to a depth of 1300 m MD. Stop drilling if unstable hole conditions persist, reservoir target depth is reached, or isolation is needed for other reasons while drilling the 7″ section.

Drilling objectives:

- Drill from 9⅝″ casing shoe to 1300 m MD. The 7″ perforated liner will be set on the bottom with at least 30 m overlap inside the 9⅝″ casing.
- Penetrate the reservoir.
- Preserve the reservoir section by minimizing mud additives that may plug the formations.
- Avoid stuck pipe situations by proper wellbore cleaning.
- Log lessons learned daily.

Anticipated hazards:

- Potential for circulation loss in fractured zones.
- Potential for reactive clays or mobile strata (RF zones) over the length of the interval.
- Potential for high bottom-hole temperature and possibility of steam or other gas kicks.
- Potential for stuck pipe situations.
- Drill with 1 single joint off bottoms during PLC or TLC.

Preparation:

- Fill the active and reserve systems.
- Ensure PVT system, backside flow meter, and trip tank indicator is operational.
- Ensure that gas sensors are operational.
- Ensure that 7″ liner, liner adapter, guide shoe and other required casing accessories are available.
- Ensure that the water pond is full and water supply is available at 1,200 gpm while drilling the 7″ section.

11.21 7″ perforated liner running procedure

Objectives:

- 7″ blank liner – Case off unconsolidated formation or cold flow zones, if any, below the 9⅝″ casing shoe.
- 7″ perforated liner - Set on bottom using liner adapter to:
  - Support production load; and
  - Provide hole stability.

11.22 Preparation for liner running

- Notify the casing running crew 72 hours in advance.
- Check and verify that all liner running and handling equipment is available on location and inspected.
- Prepare the liner running list and send to well engineer for verification.
- Liner running guide sheet (including running forces, surge calculations, related risks etc.) will be prepared in advance and submitted by the well engineers and reviewed and followed up by the DSV.
- Remove the thread protectors. Clean both pin and box ends thoroughly using water-based thread cleaner. Visually inspect threads. Inspect and drift all joints with a calibrated and approved API drift tool.

11.23 7″ perforated liner running operation

1) Pick up (P/U) the guide shoe and the liner joints. Run the blank and perforated liner joints according to the program to be provided by ODDEG. If requested by the geologist, run enough blank liner on bottom, alternating through the zones, and inside the 13⅜″ lap (minimum 30 m overlap). DSV will instruct the crew after consulting with team. Make up the 9⅝″ liner adapter and the running tool.
   a) Hold pre-job safety meeting and discuss the 7″ perforated liner running procedure.
   b) A blank joint may not be needed at hole bottom if there are deep potentially productive fractures near TD. If required, pre-assemble the liner adapter on a blank joint with swab cups in it.
   c) Rig up 9⅝″ liner running tools.
   d) Flow-check and ensure that the well is static. If not, keep it dead.
   e) In the case of partial or total loss of circulation, pump mud on the backside during running the liner.
   f) Note pick-up and slack-off weight of liner. Lower through rotary and continue to RIH on drill pipe.
   g) Swab and surge simulations should be run with different liner running speeds prior to running the blank liner. If PLC/TLC occurs, continue pumping down the annulus while

running the liner. Run the liner string at the recommended speed estimated from swab and surge calculations.

h) Watch the shakers for returns while running the casing. Notify the DSV immediately if the returns start to diminish or increase.
i) Ensure that connections are made-up properly.
j) Before entering the open hole, record pick-up and slack-off weights as well as the pressure and pump rates.
k) Set the liner on bottom. If the liner stops off bottom in the open hole (>15 m off bottom), it will be landed, and a drilling assembly will be run to clean out below the liner.

12. WELL CONTROL GUIDELINES

It is vital to always monitor the formation fluid pressures while drilling a geothermal well as a safety procedure measurement against blow outs that may arise from a kick. Kicks occur when the formation fluid pressures exceed the drilling fluid pressure and may result in a blow out if uncontrolled. Therefore, it is important to maintain the right mud weight when drilling mud is used as the drilling fluid. Here below the well control guidelines explain the procedure to follow step by step:

The "shut-in and well killing procedure" aligns with the configuration of BOPE stack and circulating system for geothermal drilling operations. The killing method for steam kicks in geothermal wells is to cool down the well by pumping down annulus with rate as high as possible. If the well cannot be killed by pumping or bull heading cold drilling fluids, proceed by implementing one of the following methods, as appropriate. The kill method for this well, if the kick cannot be subdued by cooling the well, will be the driller's method via hard shut-in. If H_2S is observed on surface, the gas will be bled through an appropriate abatement process.

12.1 Shut in while drilling, kill, and resumption of drilling operations

1) Shut in procedure for 21¼″ and 13⅝″ BOP while drilling through the potential gas bearing zones until after the 13⅜″ casing is set.
   a) Pick up the drill string to ensure the tool joint will not be on the BOP stack.
   b) Shut down the pump.
   c) Close HCR valve on the fill-up line.
   d) Close the well with pipe ram.
   e) Open the HCR valve on the choke line and read the shut-in casing pressure (SICP).
   f) Fill up the kill sheet with all available information (SICP, kick time, any pit gain).

   The well is now in shut-in condition; proceed with killing the kick with drillers method.

2) According to the American Petroleum Institute's Recommended Practice for Blowout Prevention Equipment Systems for Drilling Wells (API RP 53), Driller's method procedure will be implemented after the well is shut in. Kill sheet needs to be ready and filled with pre-recorded information in every kick occurrence (API, 2022).
   a) Record shut in casing pressure.
   b) The shut-in drill pipe pressure (SIDPP) reading will be zero after shut in condition due to the float on the string. Obtain the SIDPP by turning on the pump with the lowest pump rate that can be achieved.
      i) The drill pipe pressure gauge will increase and pay attention until "LULL" achieved. Stop pumping and record SIDPP, or
      ii) Continue pumping until the casing pressure increases 20 psi from the last SICP. Stop pumping. The SIDPP = Current reading drill pipe pressure – 20 psi.

c) Record the SIDPP number on the kill sheet and daily report and calculate required kill mud weight (KMW) and add 0.2 ppg as safety factor (SF).
d) Prepare for the initial circulation using the existing mud weight (OMW) to circulate out the kick while ensuring constant Bottom Hole Pressure (BHP).
    i) Bring the pump up to speed to the Slow Pump Rate (SPR) while maintaining constant casing pressure.
    ii) After reaching the SPR, record the initial circulating pressure (ICP) and maintain this value by manipulating the choke until gas reaches the surface.
    iii) Continue circulating until the calculated pump stroke from surface to surface is reached. Once this is achieved, shut off the pump and fully close the choke manifold.
    iv) Note: When shutting off the pump, decrease the flow rate slowly while maintaining constant casing pressure. Finally, read both gauges on the drill pipe pressure (DPP) and casing pressure. If casing pressure (CP) is greater than DPP, repeat the initial circulation process."
e) Ensure that the calculated kill mud weight (KMW) has been properly mixed.
f) Prepare for the second circulation by displacing the KMW into the hole while maintaining constant Bottom Hole Pressure (BHP).
    i) Bring the pump up to the Slow Pump Rate (SPR) while maintaining constant casing pressure.
    ii) During the pumping of the kill mud weight from the surface to the bit, keep the casing pressure constant. After the KMW has reached the bit, record the drill pipe pressure reading as the final circulating pressure (FCP) value.
    iii) Maintain the FCP constant while pumping the KMW from the bit to the surface.
    iv) Continue circulating the well until the mud weight in (MWin) equals the mud weight out (MWout) and the surface-to-surface stroke number has been reached.
    v) Once the desired conditions are achieved, shut off the pump and fully close the choke manifold.
    vi) Note: When shutting off the pump, decrease the flow rate slowly while maintaining constant casing pressure.
    vii) Read both gauges on the drill pipe pressure (DPP) and casing pressure. If the casing pressure (CP) is greater than the DPP, repeat the first circulation process as described in step (d) and then continue with the second circulation process as outlined in step (e) above.
    viii) After confirming the well is dead, close the Hydraulic Choke Remote (HCR) valve on the choke line before resuming drilling operations.

3) Shut-in procedure for 13⅜″ BOP while drilling through the reservoir after the 13⅜″ casing is set, and the well is under circulation loss condition.
    a) Do not stop pump.
    b) Space out.
    c) Chain the brake down with the tool joint approximately 2 m above the rotary table. Or ensure the tool joint is not on the BOP stack.
    d) Stop pumping fluid down annulus.
    e) Close the pipe ram.
    f) Open the HCR choke valve.
    g) Don’t open the choke line.

    The well is now in shut-in condition; proceed to killing the kick with bullhead method.

4) Perform the bullheading procedure after shutting in the well while drilling, following the setting of the 13⅜″ casing.
    a) Continue pumping down the drill string.

   b) Pump down annulus with two mud pumps (one pump to kill line and one pump to choke line).
   c) During killing process, close the annular and 10″ air drilling isolation valve. Open the pipe. Ram and regularly work drill string through annulus to check pipe is free.
   d) Monitor casing pressure gauge until casing pressure drops to zero.
   e) In the event that the casing pressure does not drop off, gradually increase pump rate, keep increasing pump rate until pressure drops to zero.
   f) Stop pumping, slowly open choke valve to check there is no flow, indicating well is dead.
   g) To resume drilling:
      i) Close the Hydraulic Choke Remote (HCR) valve.
      ii) Line up centrifugal pump to the T-pipe on the 4-1/16″ fill-up line, install check valve upstream of the manual valve. Using "T-pipe" to connect the same line to mud pump.
      Note: The common arrangement is that a centrifugal pump and a mud pump are connected to the wing valve of the 13⅜″ permanent wellhead to enable pumping down the annulus using either the centrifugal pump or the mud pump. However, since the wellhead is positioned below ground level, connecting it to the wing valve is not operationally viable. Consequently, the fill-up line on the mud cross must be fitted with a 4-1/16" manual and HCR valves and include a T-pipe with a manual valve and check valve to the centrifugal pump.

5) BOP and well control valve position after well killing prior to resume drilling:
   a) Annular BOP is open.
   b) Both HCR and choke valves should be in a closed position.
   c) Depending on the drilling condition:
      i) If normal drilling without air should be continued, the 10″ flow line valve must be in open position and the 10″ air drilling isolation valve must be closed.
      ii) If air drilling will be continued, the 10″ flow line valve must be closed and the 10″ air drilling isolation valve must be open.
   d) Line up all mud pumps to the standpipe.
   e) Mud pump will be connected to fill-up line and temporary wellhead to pump down the annulus.
   f) Continue drilling. Shut in while tripping, kill, and resumption of tripping operation. While tripping, the centrifugal pump must be run continuously down the annulus at a sufficient pumping rate to keep the well dead (HCR fill-up valve open) and the annulus full, if possible. If the well kicks during tripping operations, shut in the well in accordance with the following procedure:
      i) Shut-in procedure while tripping through the potential gas bearing zones until after the 13⅜″ casing is set.
         α) Position the tool joint approximately 2 m above the rotary table and set slips. Ensure tool joint is not on the BOP stack.
         β) Lower tool joint to approximately 0.5 m above the rotary table and chain the brake.
         χ) Stop pumping down annulus (check valve is available to prevent back flow to centrifugal pump).
         δ) Close the annulus.
         ε) Close HCR valve to the fill-up line.
         The well is now in shut-in condition, proceed with killing the kick.

6) Kill well procedure after the well is shut in while tripping through the potential gas bearing zones until after the 13⅜″ casing is set.
   a) Strip the drill string back into bottom.
   b) Conduct a kill procedure as if the well was shut in while drilling.

The well is now in static condition. Tripping operations may continue after opening the well. Continue tripping while pumping down annulus.

7) Shut-in procedure while tripping during drilling the production zones after the 13⅜″ casing is set.
   a) Position the tool joint approximately 1.5 m above the rotary table and set slips. Ensure tool joint is not on the BOP stack.
   b) Make up Total Depth Sub (TDS) to drill string.
   c) Lower tool joint to approximately 0.5 m above the rotary table and chain the brake.
   d) Stop pumping down annulus (check valve is available to prevent back flow to centrifugal pump).
   e) Close the annulus.
   f) Close HCR valve to the fill-up line.

   The well is now in shut-in condition, proceed with killing the kick.

8) Kill well procedure after the well is shut in while tripping during drilling the production zones after the 13⅜″ casing is set.
   a) Line up two mud pumps on the kill line.
   b) Pump down kill line with two mud pumps.
   c) Move the drill string through the annulus to check pipe is free.
   d) Monitor casing pressure gauge until casing pressure drops to zero. In the event that the casing pressure does not drop of in pressure, gradually increase pump rate. Keep increasing pump rate until pressure drops to zero.
   e) Slowly open choke valve to check there is no flow, indicating well is dead.
   f) Close choke valve, and open isolation valve to centrifugal pump.

   The well is now in static condition, tripping operations may continue after opening the well. Continue tripping while pumping down annulus.

9) Shut in while running perforated liner.
   a) The following preparation is required to run perforated liner:
      i) Have blank casing connected to circulating swage and 2″ safety valve (SOV) with appropriate hammer union on pipe rack.
      ii) Make sure the valve is in the open position.
      iii) Make sure blank casing is attached by slings and ready to pick up by crane.
   b) The procedure to shut in the well while running perforated liner is as follow:
      i) Lower liner / casing to the rig floor to position the perforated section below the rotary table (RT), set slips.
      ii) Pick up blank casing that is connected with circulating swage and 2″ safety valve.
      iii) Connect blank casing with perforated casing.
      iv) Lower blank casing with elevator, set slip.
      v) Close the 2″ safety valve, close the annular BOP.
      vi) Connect circulating swage with circulating hose.
      vii) Open the valve.

   The well is now in shut-in condition, proceed to kill the well.
   Note: In case of a severe steam kick to the rig floor, where there is insufficient time to safely install the circulating swage, release the casing elevator and allow the casing string to drop into the hole. Close the blind ram.

13. RIG SELECTION AND SIZE

Rig selection should be based on planned depth and well construction. Since drilling constitutes a high percentage of geothermal development cost, selecting an appropriate rig machine (mobile or land rig) with sufficient capacity, high efficiency and low drilling cost, is vital. The main factors affecting the rig selection as determined by L'Espoir (1984) are:

- Draw work capacity;
- Mast hook load capacity;
- Power transmission;
- Hoisting system;
- Rotary system;
- Circulation system;
- Assembly;
- Crown block and travailing block capacity;
- Drilling lines size and pulling over force;
- Rig pumps and power capacity;
- Drill pipe size (5″ or 4½″);
- Rig substructures suitable for safe installation of the BOP stack; and
- Well location and rig layout.

Table 38 lists rated power and minimum required rig capacity for selected rig types (land or mobile rig).

TABLE 38: Minimum rig capacity and power rate required for selected rig types (land or mobile rig)

Drawworks rated power HP (kW)	**Hookload in tone (T)**	
	Land rig	**Mobile rig**
150		60
200		75
250		80
300		90-100
500		125
700	180	180
1000	225	225
1500	350	350
2000	500	
3000	750	
4000	1000	
5000	1500	

13.1 Rig selection for Asal site

In 2006, the first well (GLG-1) was drilled with a drilling rig machine called CF2000, with a hook load capacity of 40 metric tons. The minimum capacity standard for the drilling rig hook load is 60 metric tons (Sigurdsson, 2021). After encountering problems due to the small capacity of the rig machine, the Djibouti Office for Geothermal Energy Development (L'Office Djiboutien de Développement de l'Energie Géothermique; ODDEG) purchased a brand new PM-225 metric tons rig to drill future wells.

13.1.1 Hook load capacity selection

Assume a vertical well with a total depth of 1300 m needs to be drilled with the following sizes specifications (Figure 21).

- Surface casing 20″ #94 ppf set at 200 m depth;

- Intermediate casing 13⅜″ #68 ppf set at 450 m depth;
- Perforated liner 9⅝″ #43.5 ppf set at 850 m depth;
- Liner is run on drill pipes and hung at 1270 m depth;
- Liner weight reduction due to perforations is 10%;
- Drill pipes = 5″G105, 19.5 lb/ft, NC50 with tool joint outside diameter (OD) of 161.9 mm;
- BHA = 120 m length and 25 tons in air;
- The water table in the well is at a 200 m depth; and
- The safety factor for all hook loads is SF = 1.5 and a 23 tons overpull is required.

SF	1.5			ppf to kg/m		1.48816		BF	0.873		Water Table		200	m	
								Buoyed Weight per	Air Weigth for top	Buoyed Weight from water table to TD	Total Weight	Total wt tons		Weight with SF and	Tons
Surface Casing		200	m	94	ppf	139.89	kg/m	122.121	27977.4	0	27977.4	28		41966.1	42
Anchor Casing		450	m	68	ppf	101.19	kg/m	88.3431	20239	22085.77366	42324.7	42		63487.1	63
Production Casing		850	m	43.5	ppf	64.735	kg/m	56.5136	12947	36733.83824	49680.8	50		74521.2	75
			Liner weight reductio		0.9										
Production Liner															
	Top	850	m	26	ppf										
	Bottom	1270	m	23.4	ppf	34.823	kg/m	30.4004		12768.1755					
	Length	420	m												
Drill Pipes		850	m	38.84	kg/m			33.9073	7768	22039.758					
										Total weight for running liner		42576		63863.9	64
During Drilling												43	tons		
TD		1300	m												
BHA		120	m	25000	kg					21825					
Drill Pipes		1180	m						7768	33229.1736					
										Total Weight for Drilling		62822		94233.3	Greatest Load
											Greatest Load	63	tons		94.2332604
														128733.3	
														Rig Size	180

FIGURE 21: Calculation of rig size required to drill a geothermal well of 1300 m depth

1) Calculate the loads required to drill to TD and to run each casing/liner string.

   This is to determine the weight that the drilling rig's hook needs to support for various stages of the well construction process. This includes the weight of the drill pipes, the bottom hole assembly (BHA), and each casing or liner string. The safety factors and adjustments for factors like the water table and liner weight reduction are also considered.

2) What is the greatest load encountered during the drilling of this well?

   The aim is to identify the maximum hook load that the drilling rig will need to support at any point during the drilling process. This will help ensure that the rig selected can handle the highest loads expected during well construction.

3) What is the required rig size based on the operator's specifications for safety factor and overpull?

   The goal here is to determine the size and capacity of the drilling rig needed based on the safety factors and overpull requirements specified by the operator. This ensures that the selected rig can safely handle the anticipated loads and provide the necessary margin of safety.

4) What would be the required rig size for a standard well in a geothermal field in your home country?

   This is to compare the calculated maximum hook load to the capabilities of rigs commonly used in geothermal fields in your home country. This will help determine the appropriate rig size and capacity for drilling similar wells in your local geothermal context.

14. DISCUSSION

In this section, the results and outcome of the design calculations as shown above in Tables 8-18 are discussed. These calculations have been done referring to the *African Union Code of Practice for Geothermal Drilling* (African Union's Regional Geothermal Coordination Unit, 2016). Sour service materials casing grades are used such as K-55 for the surface casing and L-80 for the anchor and production casings, as shown in Table 8.

14.1 Collapse / burst pressures during cementing

The calculations of the casing strength against collapse were done for the three different sections, a 20″ 94 lb/ft K-55 surface casing, a 13⅜″ 68lb/ft L-80 intermediate casing and a 9⅝″ 47 lb/ft L-80 production casing, to find out whether the selected grades are strong enough to resist the pressure exerted during cementing. This was completed by comparing the results against the minimum design factor specified in the *African Union Code of Practice for Geothermal Drilling* (2016). The results for collapse pressure for the surface casing at 250 m was 1.96 MPa with a design factor of 1.83, for the anchor casing at 450 m it was 3.53 MPa with a design factor of 4.42, and for the production casing at 800 m it was 6.28 MPa with a design factor of 5.22. Referring to the *African Union Code of Practice*, the minimum design factor should be 1.2, which is reached in all three cases (Table 9).

The calculations of the collapse pressure against burst during cementing were done for the three different sections, the 20″ 94 lb/ft K-55 surface casing, the 13⅜″ 68lb/ft L-80 intermediate casing and the 9⅝″ 47 lb/ft L-80 production casing, to find out whether the selected grades are strong enough to resist the pressure exerted during cementing. This was completed by comparing the results against the minimum design factor specified in the *African Union Code of Practice for Geothermal Drilling* (2016). The results for burst pressure for the surface casing at 250 m was 2.16 MPa with a design factor of 6.72, for the anchor casing at 450 m it was 3.73 MPa with a design factor of 9.28, and for the production casing at 800 m it was 6.48 MPa with a design factor of 7.31. Referring to the *African Union Code of Practice*, the minimum design factor should be 1.5, which was reached in all three cases (Table 10).

14.2 Axial loading before and during cementing

The axial loading results were obtained assuming the worst-case scenario, where the internal fluid is water and the displaced fluid is cement. For the surface casing, the hookload was -96 kN with a design factor of -67.9. For the anchor casing, the hookload was 71.3 kN with a design factor of 96.95, and for the production casing, the hookload was 185.6 kN with a design factor of 25.99. The negative sign indicates a compressive load acting downwards. Since the minimum required design factor was 1.8, the design was deemed adequate in all three cases (Table 11).

14.3 Axial loading after cementing

The axial load may rise or decrease after the cementing job depending on whether the temperatures increase or decrease in the well. Three scenarios have been tested for different casing strings. The surface, anchor and production casings were set at temperatures of 30°C, 35°C, and 40°C, respectively. The maximum temperatures at the surface, anchor and production casings were 95°C, 127°C, and 183°C, respectively. Results are listed in Table 12 above. The negative values indicate a compressive force acting downwards. The temperature may decrease after the cementing job due to the circulation of cold fluid in the well and cause a tensile force. Three scenarios have been tested for the surface, anchor and production casing strings. The maximum temperature at the surface, anchor and production casings at the time of cement set were set to 30°C, 35°C and 40°C and the minimum temperature after cooling the well was set to 20°C. Results are listed in Table 13 above. The design factor in the older version of the NZ standard (1991) was 1.2 but in the revised standard (both NZ and AU) no design factor is specified. Instead, they have assumed that all casings will thermally yield. Therefore, the limited plastic strain design needs to be applied as stated in the *African Union Code of Practice for Geothermal Drilling* (2016) in clause 2.10.3.4, but this is out of the scope of this report. The results, compared to the design factor in the old version from 1991, are satisfactory.

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

Due to the lifting force by the fluid in the well, a strain at the top of the anchor casing may be generated. The well is assumed to be full of steam with a maximum wellhead pressure of 9.7 MPa and with an ANSI class of 900 for safety instead of ANSI class 600, as fluid of extremely high salinity may come up from the borehole to the surface. To determine the tensile force that might occur at the top of the anchor casing due to the lifting fluid in the well, calculations were done for the 13⅜″ 68 lb/ft L-80 anchor casing supporting the wellhead. The results were that the tensile strength is 6912.3 kN and the tension force is 756 kN. The design factor calculated in Table 14 is 9.14, which is higher than the required standard design factor of 1.8. Therefore, the selected grade is adequate and the design is safe.

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

It is likely that the production casing rises into the wellhead during the production phase of the well. Therefore, a lifting load could be applied to the anchor casing during production. Two scenarios using different casing weights of grade L-80 were compared. The results showed a design factor of 8.2 for the 61 lb/ft casing and 9.14 for the 68 lb/ft casing, which is much higher than the required minimum design factor of 1.4 (Table 15).

14.6 Helical and buckling calculations for liner casing

The 7″ un-cemented liner is subject to axial self-weight and helical buckling, which was calculated considering the temperature reduction factor for different grades, that is L-80 and K-55. The temperature reduction factor for grade K-55 is 0.7 and the minimum tensile strength is 379 MPa. The temperature reduction factor for grade L-80 is 0.8 and the minimum tensile strength is 551 MPa. The computed design factor is 0.69 for K-55 and 1.17 for L-80, while the standard design factor is 1. This shows that grade K-55 is not suitable, while L-80 fulfils the requirements (Table 16).

14.7 Internal differential pressure at the casing shoes

The maximum internal differential pressure at the casing shoes of the surface, anchor and production casings were calculated and the results are listed in Table 17. For all selected casings, the design factor was greater than the minimum design factor standard of 1.5.

14.8 External differential pressure at the casing shoes

The maximum external differential pressure at the casing shoes of the surface, anchor and production casings were calculated and the results are listed in Table 18. For all selected casings, the design factor was greater than the minimum design factor standard of 1.5.

14.9 External differential pressure during production operation

The maximum external differential pressure arises near the casing shoe. The maximum pressure downhole is 9.7 MPa and the design factor is calculated in Table 19 assuming full steam from the bottom of the borehole to the surface. Comparing grades K-55 and L-80 shows that L-80 has a higher pipe collapse pressure of 32.8 MPa, while for K-55 it is 26.8 MPa. The calculated design factor for L-80 is 3.38, while the design factor calculated for K-55 is 2.76, which are both greater than the minimum design standard factor of 1.2.

15. CONCLUSION AND RECOMMENDATION

The geothermal fluid in the Asal area has high salinity (120 g/L), which needs to be taken into consideration when selecting proper casing grades for sour service to protect against gases that might be present in the borehole such as H_2S.

Scaling is one of the critical issues that needs to be considered, especially in the area where the salinity of the fluid is high. In order to minimize scaling in the well, solutions need to be adopted, e.g. by considering selecting a larger diameter such as 13⅜″ for the production casing and by controlling pressure drop in the well. In addition, a well design with a deeper production casing should be considered in order to avoid the deposition zone appearing inside the liner, allowing for a location where a cleaning operation could be successful.

The determination of the minimum casing depth relies on assessing pore pressure and fracture gradient. This evaluation draws from various sources, including data from nearby wells detailing geological formations, temperature and pressure profiles. Alternatively, it may follow the casing design guidelines outlined in the African Union Code of Practice for geothermal drilling (African Union's Regional Geothermal Coordination Unit, 2016).

K-55 has been selected for the surface casing and L-80 for the other casing sections, due to the extreme salinity of the fluid, which may reduce the lifetime of the well and its productivity. L-80 allows for more control on composition than K-55 and has a higher minimum tensile strength of 551 MPa. Referring to the African Union Code of Practice for Geothermal Drilling (2016), clause 2.10.1.4 (b), the K55 has a minimum yield strength of 379 MPa. Well design, whether for deep or shallow geothermal wells, is an enormous challenge. Therefore, proper selection of API 5CT standard casing grades and ANSI B16.5 or API SPEC 6 A-D standard wellhead is required.

Refering to the *African Union Code of Practice for Geothermal Drilling* (2016), clause 2.10.3.4, conventional design factors are not applicable for casings that are designed to yield. Therefore, if that is the case, limited plastic strain design is mandatory. To ensure a cost-effective and long lifetime of the well and to avoid casing failure, it is recommended to benefit from the technology invented by ÍSOR, namely Flexible coupling (FC). These couplings are attached to casing joints replacing conventional couplings and enable controlled thermal expansion of the casing, improving the well integrity and well productivity.

ACKNOWLEDGEMENT

First of all, I would like to thank God, the most helpful.

Then, I would like to express my deep appreciation for the entire GRÓ GTP team for their humble support from the beginning of this 6 months course up to the end. A warm thank you also goes to my supervisor, Gunnar Skúlason Kaldal, for his support in helping me to accomplish this project. Finally, my sincere thanks goes to my parents for their encouragement that kept me motivated during the training period.

REFERENCES

African Union's Regional Geothermal Coordination Unit, 2016: *The African Union code of practice for geothermal drilling*. African Union, 130 pp.

API, 2022: Recommended practice for blowout prevention equipment systems for drilling wells (API RP 53). American Petroleum Institute, Washington DC, USA, 82 pp.

Aquater, 1989: *Djibouti geothermal exploration project, Republic of Djibouti*. ISERST, Aquater, and Intairdrill, final report, San Lorenzo in Campo, 231 pp.

Barberi, F., Civetta, L., and Varet, J., 1980: Strontium isotopic composition of Afar volcanics and its implication for mantle evolution. *Earth Planet. Sci. Lett., 50,* 247-259.

BRGM, 1975: *French territory of Afar and Issas. End of survey report: Results of the first well testing.* BRGM, report 75-SGN-442-GTH (in French), 18 pp.

Elmi, H.D., 2005: Analysis of geothermal well test data from the Asal rift area, Republic of Djibouti. Report 6 in: *Geothermal Training in Iceland 2005.* United Nations University Geothermal Training Programme, Reykjavík, Iceland, 21 pp.

Finger, J.T. and Blankenship, D.A., 2010: *Handbook of best practices for geothermal drilling*. Sandia National Laboratories, Albuquerque, New Mexico, USA, report SAND2010-6048, 84 pp.

Gabolde, G. and Nguyen, J.P., 2014: *Drilling data handbook (9^{th} ed.).* Editions Technip, Paris, France, 576 pp.

Gercek, H., 2006: Possion´s ratio values for rocks. *International Journal of Rock Mechanics & Mining Sciences, 44(1),* 1-13.

Hatherton, T. and Leopard, A.E., 1964: The density of New Zealand rocks. *New Zealand Journal of Geology and Geophisics,7(3),* 605-625.

ISERST, 1985: *Carte geologique de la République de Djibouti* à *1:100,000: Tadjoura.* ISERST, report (in French), 139 pp.

Jalludin, M., 2009: State of knowledge of the geothermal provinces of the Republic of Djibouti. *Presented at "Short Course IV on Exploration for Geothermal Resources", organized by UNU-GTP, KenGen and GDC, Lake Bogoria and Lake Naivasha, Kenya,* 14 pp.

Jalludin, M., 2010: State of knowledge of the geothermal provinces of the Republic of Djibouti. *Presented at "Short Course V on Exploration for Geothermal Resources", UNU-GTP, GDC and KenGen, Lake Bogoria and Lake Naivasha, Kenya,* 16 pp.

L'Espoir, J., 1984: How to determine your rig's depth limit. *Petroleum engineer international, 56(5),* 70-80.

Sanjuan, B., Michard, G., and Michard, A., 1990: Origin of dissolved substances in the waters of thermal springs and boreholes of the Asal-Ghoubbet region (Republic of Djibouti) (In French). *J. Volc. and Geothermal Research, 43,* 333-352.

Sigurdsson, Th., 2021: *Drilling rig and equipment*. Lecture presentation, 12 pp.

Skúlason Kaldal, 2021: *Geothermal well design. Casing design: Loads and failure modes – Part 2*. ÍSOR – Iceland GeoSurvey, lecture presentation, 57 pp.

Standards New Zealand, 1991: Code of practice for deep geothermal wells (NZS 2403:1991). Standards New Zealand, Wellington, New Zealand, 96 pp.

Standards New Zealand, 2015: Code of practice for deep geothermal wells (NZS 2403:2015). Standards New Zealand, Wellington, New Zealand, 116 pp.

Thorbjörnsson, I.O. and Kaldal, G.S., 2021: Flexible couplings for improved casing design in high-temperature geothermal wells. *Proceedings World Geothermal Congress 2020+1, Reykjavik, Iceland,* 4 pp.

Virkir-Orkint, 1990: *Geothermal scaling and corrosion study.* Virkir-Orkint, final report, 273 pp.

NOMENCLATURE

Abbreviations

ALAP = Apparent Low-Amplitude Pulsations;
API = American Petroleum Institute;
AS = Andesitic series;
AU = African Union;
Bakerlok = Thread-locking compound;
BHA = Bottom hole assembly;
BHT = Bottom hole temperature;
BOP = Blowout preventer
BOPE = Blowout preventer equipment;
BPD = Boiling point depth;
BTC = Buttress thread casing;
CHF = Casing head flange
DC = Drill collar;
FLOT = Formation leak-off test;

DF	=	Design factor;
DP	=	Drilling pipe;
DSV	=	Drilling supervisor;
EM	=	Electromagnetic;
GLG	=	Gale le Goma;
GPM	=	Gallon per minute;
HCR	=	High capacity relief valve;
HWDP	=	Heavy weight drill pipe;
IADC	=	International Association of Drilling Contractors;
LCM	=	Lost circulation material;
LULL	=	Lowest unstable liquid level;
LWD	=	Logging while drilling;
MD	=	Measured depth;
MWD	=	Downhole measurement while drilling;
NMDC	=	Non-magnetic directional coupling;
NRV	=	Non-return valve;
NZ	=	New Zealand;
PLC	=	Pressure leak check;
POOH	=	Pull out of hole;
ppf	=	Pounds per foot;
ppg	=	Pounds per gallon;
PVT	=	Pressure, volume, and temperature
PWD	=	Pressure while drilling;
REG	=	Regular;
RIH	=	Run in hole;
RPM	=	Revolutions per minute;
SG	=	Specific gravity;
SI	=	International system of units;
SIDPP	=	Shut-in drill pipe pressure;
SOW	=	Stab-on while drilling;
TAS	=	Total alkali-silica;
TD	=	Total depth;
TFA	=	The total flow area;
TLC	=	Temperature leak check;
TVD	=	True vertical depth;
WHP	=	Wellhead pressure;
WOB	=	Weight on bit; and
XO	=	Crossover, a component used to connect two pieces of equipment with different thread connections.

Variables, constants and units

a, α	=	Coefficient of thermal expansion (°C);
A_p	=	Cross-sectional area of casing wall (mm^2), allowing for any slotting;
Cp	=	Plastic viscosity;
cP	=	Centipoise;
d	=	Casing inside diameter (mm);
D	=	Casing outside diameter (mm);
e	=	Eccentricity (mm) = actual (not nominal) hole diameter minus D;
E	=	Modulus of elasticity (MPa);
f_b	=	Maximum stress due to bending (MPa);
f_c	=	Total extreme fibre compressive stress due to axial and bending forces (MPa);
f_t	=	Maximum tensile stress (MPa);
$F_{buoyancy}$	=	Buoyancy force (kN);

$F_{csg\ air\ wt}$	=	Air weight of casing (kN);
$F_{csg\ contents}$	=	Weight of internal contents of casing (kN);
$F_{hookload}$	=	Surface suspending casing that is subject to gravitational and static hydraulic loads (kN);
$F_{displaced\ fluids}$	=	Weight of fluids displaced by casing (kN);
F_c	=	Change in axial force within casing body due to heating (kN);
F_m	=	Net downward force applied by the wellhead (kN), due to its own mass and any pipework reactions (kN);
F_p	=	Axial force within casing body at cement set (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_w	=	Lifting force due to wellhead pressure (kN);
g	=	Acceleration due to gravity (9.81 m/s^2);
I_p	=	Net moment of inertia of the pipe section, allowing for perforations (mm^4);
$klbs$	=	Kilopounds;
L_{if}	=	Vertical length of a section of fluid having the same density – within the casing (m);
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 (m);
L_z	=	Total vertical length of liner or casing (m);
P_f	=	Pore pressure (MPa);
$\Delta P_{external}$	=	Maximum external differential pressure on casing after cementing (MPa);
$\Delta P_{internal}$	=	Maximum internal differential pressure on casing during cementing (MPa);
P_{frac}	=	Fracture pressure of a formation (MPa);
ppm	=	Parts per million;
P_w	=	Maximum wellhead pressure (MPa);
P_z	=	External fluid pressure at the casing shoe (MPa);
R_i	=	Temperature reduction factor (ratio);
R_j	=	Connection efficiency in compression;
RPM	=	Rotations per minute;
S_v	=	Overburden pressure (vertical pressure due to the weight of the overlying formations) (MPa);
T_1	=	Neutral temperature (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 in air (kg/m);
v	=	Poisson's ratio;
π	=	3.14;
ρ_{ef}	=	Density of a section of fluids with constant density within annulus (kg/m^3);
ρ_{if}	=	Density of a section of fluids with constant density within casing (kg/m^3);
ρ_c	=	Cement slurry density (kg/m^3); and
ρ_f	=	Fluid density (usually water) (kg/m^3).