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IDDP-2, Well design

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ABSTRACT

The drilling of IDDP-2, well two of the Icelandic Deep Drilling Project, is being prepared for at Reykjanes, Iceland. The planned depth of the well is 5000 m with a casing running down to 3000 m and an ø8½" production section down to 5000 m. As the location of the well is planned in the vicinity of wells already drilled in Reykjanes, the formation conditions are relatively well known down to 2700 m. Formation conditions beneath 2700 m are not known but the aim is to find superheated fluid. Experience gained from drilling and operating IDDP-1 at Krafla, NE-Iceland, is most important when preparing for drilling IDDP-2. The design conditions are somewhat different, however, mostly due to the high salinity of the geothermal fluid in Reykjanes.

The design conditions for IDDP-2 are outlined and different scenarios for downhole pressure and temperature are explored. The well design is aimed at addressing the challenges caused by the high pressure and temperature expected down hole and during discharging, and also high leakages expected in the conventional production zone above 2700 m. With this in mind various casing programs and types are discussed and studied as well as different cementing methods. Based on the result of the studies a proposed well design is presented.

1. INTRODUCTION

The Iceland Deep Drilling Project was initiated in the year 2000. Its aim is to drill deep geothermal wells (4-5 km) to investigate the roots of geothermal systems and to answer the questions if it is technically and economically feasible to produce geothermal fluid at temperature and pressure above its critical point, which for fresh water is 374.15°C and 22.12 MPa.

The first IDDP well, IDDP-1, was drilled in 2008-2009 within the Krafla high temperature geothermal area in NE-Iceland. The well was vertical with a planned depth of 4500 m. Drilling progressed as planned down to around 2000 m depth when it became quite challenging. Eventually cuttings of fresh glass indicated the presence of a magma body at the well bottom and the drilling was stopped. The well was discharged and produced superheated steam with enthalpy of up to 3200 kJ/kg. The highest temperature recorded was almost 452°C making it the hottest geothermal well in the world. The well had to be quenched in July 2012, when neither of the two master valves could be operated. IDDP-1 has been discussed in several articles including a special issue of the journal Geothermics in January, 2014, and in an IDDP overview article at this WGC-2015 congress (Friðleifsson et al., 2015).

The planned location of IDDP-2 is shown in Figure 1. The vicinity of other wells not only helps with valuable information on the formation down to 2700 m depth but also adds to the drilling challenges as the production zone of those wells must be cased off.

Figure 1: The planned location of IDDP-2 at Reykjanes. The numbers indicate nearby wells.

2. DESIGN CONDITIONS FOR PRESSURE AND TEMPERATURE

The design condition for pressure and temperature in the IDDP-2 well is discussed below. The chemical properties of the fluid from the well are not known.

The planned location of the IDDP-2 well is in the vicinity of wells already drilled in Reykjanes. The formation conditions from 0 – 2700 m are therefore relatively well known. The water table is located at approximately 450 m within the geothermal system itself, and temperature and pressure can be approximated by a boiling point with depth (BPD) curve down to 2700-3000 m. Figure 2 shows the expected/calculated temperature and pressure profiles. The temperature below 3000 m is uncertain, but the figure shows the BPD curve down to 5000 m as it serves as a base case for temperature and pressure.

The biggest difference between IDDP-1 and IDDP-2 is that the formation at Reykjanes contains high salinity seawater while the Krafla area contains lower salinity brine which can be approximated by pure water. For determination of temperature and pressure for IDDP-2 the properties of standard seawater are used (3.5% NaCl solution) (Potter and Brown, 1977). It should be noted that the salinity of the fluid in the formations below 3000 m is not known so salinity could prove to be different from what is seen in the higher formations.

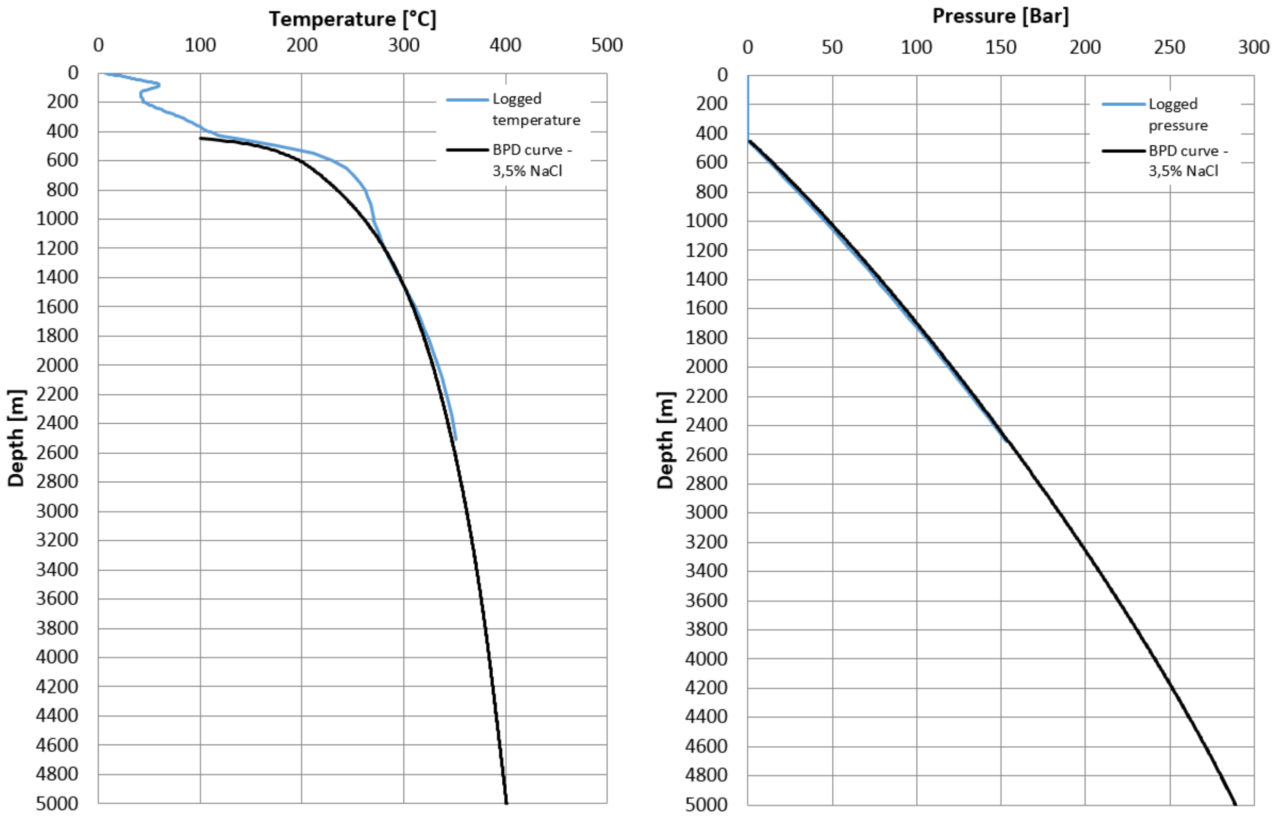

Figure 2: Estimated temperature and pressure (BPD) along with logged temperature and pressure.

The increased salinity affects the critical temperature and pressure of the fluid which for standard seawater becomes 411°C and 300 bar (Driesner, 2010) compared to 374°C and 220 bar for pure water. The effects on the boiling point v.s. depth curve (BPD) are that pressure and temperature are slightly increased for a given depth and the critical point is reached at a greater depth. The difference in depth needed to reach the critical point is quite large if the BPD curve is followed. For pure water the depth of the boiling point curve, from its top down to the critical point, is around 3500 m while for standard seawater it is around 4600 m. If the temperature and pressure follow the BPD curve below 3000 m at Reykjanes, its critical conditions won't be reached above 5000 m depth. The experience from drilling the IDDP-1, however, shows that temperature can exceed the BPD for a given depth, as discussed in section 2.3.

2.1 Minimum setting depths for casings

The general design condition for casing depth selection used here is that a column of heavy mud (SG 1.4) inside the longest casing at any time during the well construction is able to balance the pressure from a blowout in the next open hole section. It is assumed that the highest bottom hole pressure during a blowout is controlled by a hydrostatic salt water column at formation temperature down to the blowout depth. Since it is assumed that pressure and temperature follow the BPD curve for salt water, this pressure is equal to the saturation pressure of salt water at the respective bottom hole temperature.

The setting depth of the production casing is 3000 m to isolate the current production zones of nearby wells, which are located above 3000 m, from potential new ones below 3000 m. Another advantage of having such a long production casing is its ability to balance blowouts resulting from temperatures higher than indicated by the BPD curve. Figure 3 shows the saturated steam column pressures that determine the minimum setting depths for the anchor and intermediate casings which have minimum setting depths of 1190 m and 445 m respectively. The setting depth of the surface casing is chosen according to standard practice in surrounding wells.

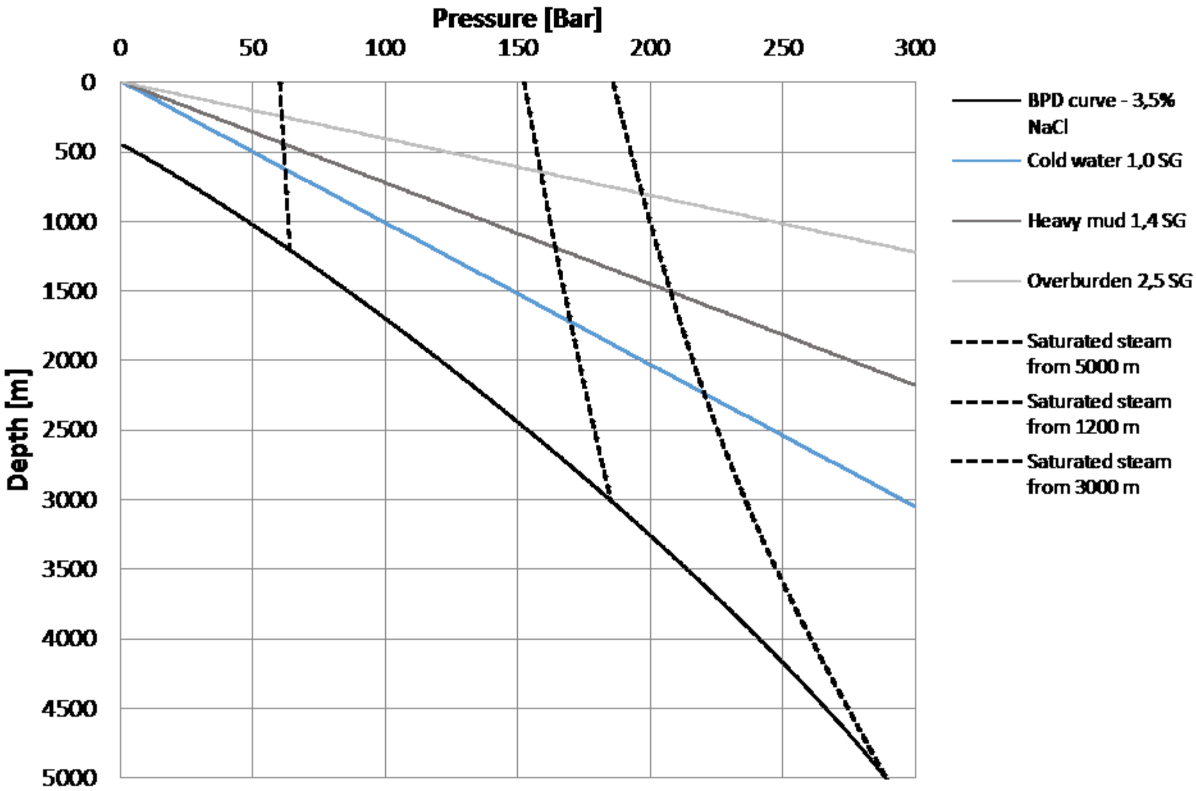

Figure 3: Estimates of the highest in hole pressures for BPD conditions.

2.2 Maximum pressure and temperature for the base case

The maximum surface temperature and pressure combination that the surface, intermediate and anchor casings have to be able to withstand assuming BPD conditions is listed in Table 1. Maximum surface pressure is represented by the top of the steam columns in Figure 3.

Table 1 Overview of the maximum surface temperatures and pressures assuming BPD conditions. Note that the uppermost 1200 m section of the production casing acts as a sacrificial casing and does not have to withstand maximum surface pressure and temperature. The wellhead is installed on the Anchor casing which in turn has to withstand the maximum in hole pressure and temperature.

			Surface casing	Intermediate casing	Anchor casing	Production casing
		in	22½	18⅝	13⅜	9⅝
	Casing depth	m	110	450	1200	3000
	Open hole depth	m	450	1200	3000	5000
Open hole						
	Highest temperature in open hole	°C	135	281	362 / 401	
	Saturation pressure at highest temperature	bar	3.1	64.0	185.2 / 289	
Wellhead						
	Saturated steam column					
	Wellhead temperature	°C	135	277	347 / 363	
	Wellhead pressure	bar	3.1	60.3	152.5 / 186.1	

2.3 Effects of temperatures exceeding the BPD curve on anchor casing and wellhead design.

The BPD curve has traditionally been used as an estimation of the highest possible combination of well pressure and temperature for unknown geothermal reservoirs. The experience from IDDP-1 shows that a sudden increase or jump in temperature beyond the BPD temperature at the BPD pressure over a relatively short depth increase is possible.

To estimate the maximum possible temperature increase below 3000 m for IDDP-2 with any certainty is difficult. Therefore the maximum allowable bottom hole temperatures for different wellhead classes is estimated. In that way a graph can be made that shows how big a temperature increase, beyond the BPD case, the well can handle depending on the wellhead design.

In conventional wells, producing wet steam, a considerable pressure drop occurs as the fluid flows up the well. During flow tests of IDDP-1 the highest measured pressure was around 141 bar. Assuming that the bottom hole pressure is close to BPD pressures the pressure at 2100 m depth should be in the range of 151 bar. It is therefore clear that the pressure difference between bottom hole and wellhead is governed by the weight of the steam column in the well and that frictional pressure drop is negligible.

For estimating wellhead pressure and temperature for different superheated bottom hole temperatures for IDDP-2, an isenthalpic steam column up the well is used where pressure drop is caused by the weight of the steam only. Bottom hole pressure for all temperatures is assumed to be equal to the BPD pressure at all depths.

Maximum temperature estimates are made for an ASME Class 1500 and 2500 wellheads and an ASME Class1500/2500 wellhead as was used for IDDP-1. Pressure ratings as a function of temperature for those wellhead configurations along with 13⅝", K55 and T95 casings are show in Figure 4 and the maximum allowed bottom hole temperatures are shown in Figure 5.

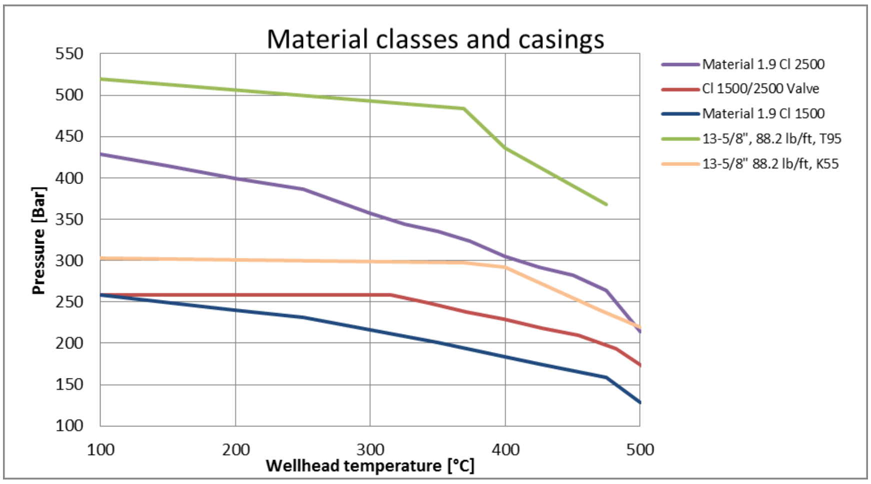

Figure 4: Pressure rating as a function of temperature for a well head with ASME Class 1500 well head valve combined with Class 2500 flanges and for a conventional Class 1500 well head. Pressure ratings for 13⅝" 88,2 lb/ft, K55 and T95 anchor casings are included for comparison.

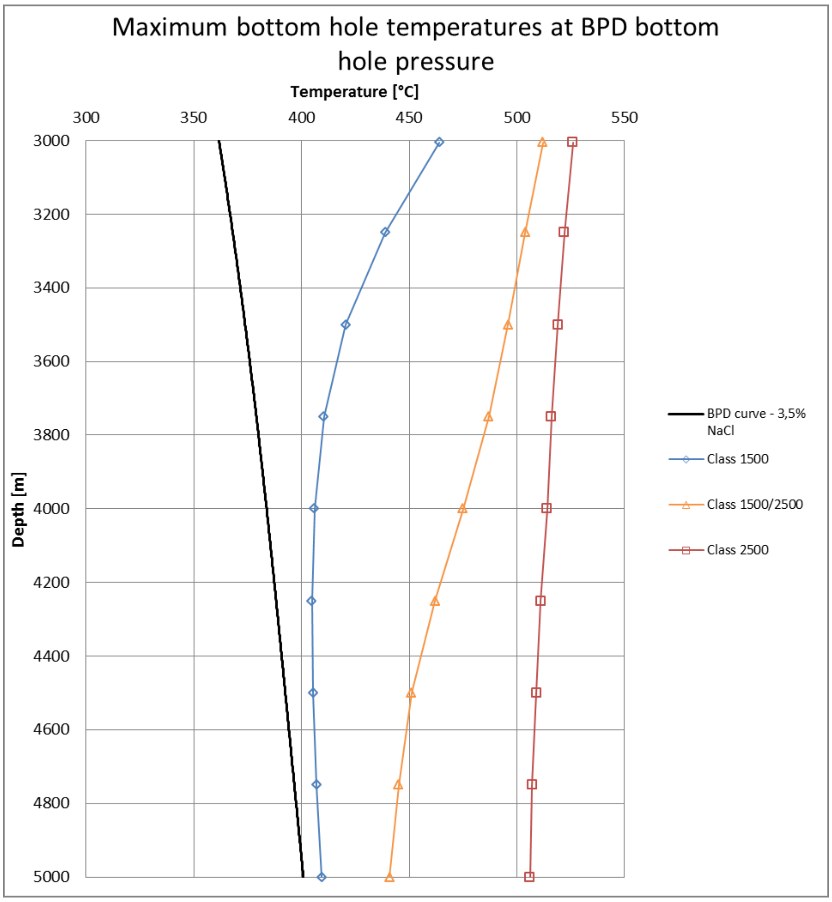

Figure 5: Maximum allowable bottom hole temperatures for a Class 2500 well head, well head with Class 1500 well head valve combined with 2500 flanges and for a conventional Class 1500 well head.

3. CASING DESIGN

3.1 Objective

The main objective for the casing design of IDDP-2 was to base the design on the current wells in the area and learn from the experience gained from drilling and operating IDDP-1.

3.2 Lessons learned from IDDP-1

The casing design of IDDP-1 proved in general to be robust enough to withstand the design conditions experienced during the drilling and operation of the well. There are, however, some opportunities for improvements including cementing methods and equipment as well as material selection of the liner.

IDDP-1 turned out to be quite different from the original design specification (Holmgeirsson et.al, 2010, Palsson et. al, 2014). One of the results was that the downhole cementing tools were used in different conditions from what was planned and the tools failed due to high temperature. By modifying the cementing methods and cementing tools, some contingency can be added to the well design.

During some of the discharge phases of IDDP-1, corrosion debris, originating from the slotted liner, was found in the well head (Ingason et al, 2014). Inspection of the top 500 m of the well did not, however, reveal corrosion damage of the production casing. Given that the condition in IDDP-2 will be similar to those in IDDP-1 one concludes that corrosion of the liner will be more critical than the corrosion in the upper part of the well. Revision of the material selection of the liner should therefore be considered.

The quenching of the well resulted in failure of the sacrificial production casing, as was to be expected. The lesson learned from that is to minimize the likelihood that quenching will be required, for instance by modifying the well head and discharge equipment design. If the well must be quenched, the thermal shock can be reduced by modifying the method such as by using hot water as killing fluid. At the same time modifications of the casing design are being looked into as described in 3.3.

The material in the top part of the anchor casing must be T95 in order to withstand the burst load. At the same time K55 is preferred elsewhere in casings as its yield properties are better suited for the high temperature environment (Thorhallsson et.al, 2003). Changing the casing material from T95 to K55 causes stress concentration in the inner production casing according to simulations and the experience from IDDP-1 supports this as production casing ruptured close to this point. This stress concentration can be reduced by increasing the wall thickness of the K55 casing.

The couplings of the anchor casing and production casing in IDDP-1 were of Hydril 563 type. These couplings were selected because of strength and gas tightness. The couplings of the anchor casing in IDDP-2 will be of the same type but the couplings in the production casing will be conventional buttress threads (BTC). The reason for this selection is that the production casing does not need to be gas tight and the strength of the Hydril 563 couplings did not prevent them from rupturing in IDDP-1.

3.3 Possibilities in casing design

Numerous casing design options where looked into before settling on the final design for the IDDP-2 well. Figure 6 shows an overview of possible casing configurations and design solutions.

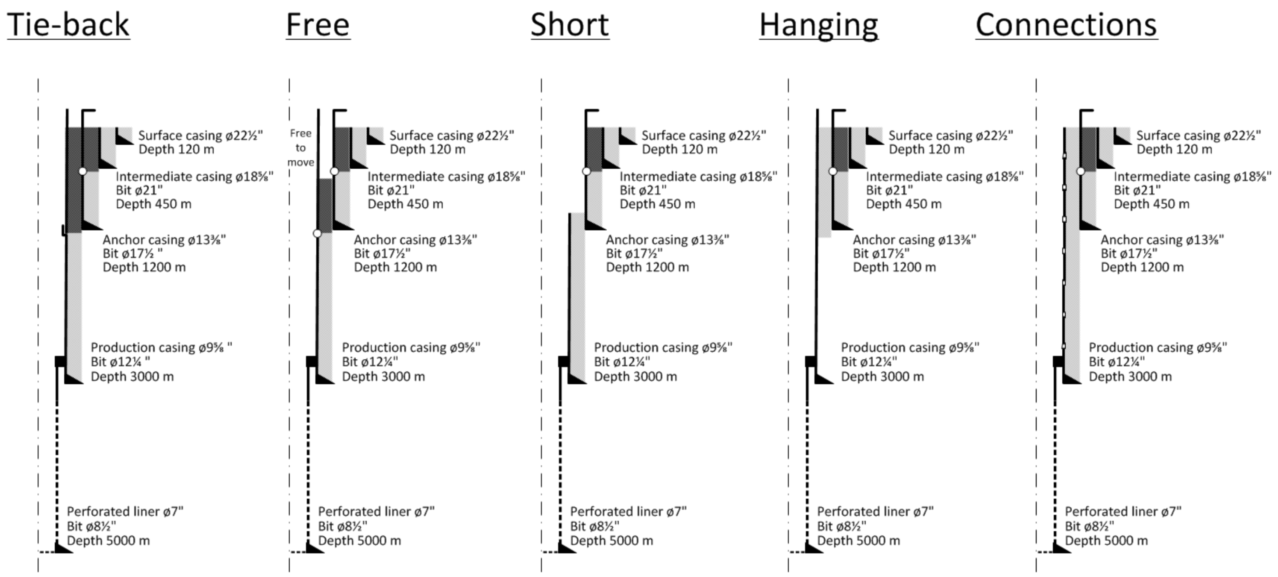

Figure 6: Some of the options in casing design which were evaluated during the IDDP-2 design.

<u>3.3.1 Tie Back</u>

Due to the length of the production casing cementing has to be performed in two stages to prevent casing collapse. The Tieback configuration was proposed as an alternative to a conventional cementing window to allow for two stage cementing. The advantage of tieback cementing compared to some two stage cementing tools is that no temperature sensitive rubber connections, which can fail under high temperature conditions, are present. Connecting the tieback liner can be problematic because of cementing material debris from previous cementing operation.

3.3.2 Free

The Free design addresses to some extent the problem of thermal stress induced when heating up and cooling down a fully cemented casing. This design allows free movement of the uppermost part of the production casing, thus preventing thermal stresses in the un-cemented section of the casing. The biggest cons are that the space between the production and anchor casing could be exposed to brine and the expansion spool has to allow for increased movement of the production casing.

3.3.3 Short

The Short design aims to save cost by shortening the production casing. This design is more suitable for reservoirs with known brine properties since the anchor casing is exposed to erosion and corrosion. As fluid properties for IDDP-2 are unknown, inclusion of a sacrificial production casing is of great value if the fluid turns out to be highly corrosive.

3.3.4 Hanging

The Hanging design, like the Free design, aims to reduce thermal stresses. Only the top part is cemented and the bottom part hangs freely allowing for free expansion or contraction. The biggest obstacle for this design is that a packer would have to be installed at the production casing shoe. The packer would have to allow for a great deal of movement while still maintaining a proper pressure sealing. Due to the high expected temperature and the location of the packer, finding a suitable packing solution becomes challenging.

3.3.5 Connections

The last design aims to reduce thermal stresses by designing casing connections that allow for expansion of the casing during heat up of the well. If the well has to be cooled down again, the connections allow for contraction equal to the expansion experienced during heat up. The proposed casing connection does not exist and can therefore not be implemented in the design of the IDDP-2 well, but the design of such a connection is being looked into.

3.3.6 Low thermal expansion material

The possibility of using a casing material with a low thermal expansion coefficient was discussed. There are materials such as ceramics and some nickel –iron alloys that do experience very little thermal expansion and could, potentially, solve some of the problems related to thermal stresses in geothermal casings. Well casings made out of such materials are not, however, readily available.

3.3.7 Tubing

Practice in the oil industry is to install production tubing in wells. Similar arrangement may be made in the IDDP well. A tubing will protect the casings from chemically aggressive fluid and it may also reduce the temperature to which the casings will be exposed. Possible arrangement of the tubing is shown in Figure 7.

Among the disadvantages of this arrangement are:

- The master valve cannot be operated when the tube is in the well
- It will be difficult to clean the tube out of the well if it breaks
- To remove the tube the well must be killed which will result in a temperature shock of the casings
- The tube could reduce the flow up the well and high velocity in the tube may cause structural problems
- Due to the high pressure expected in the well it may turn out to be difficult to fill the annulus outside the tube with gas

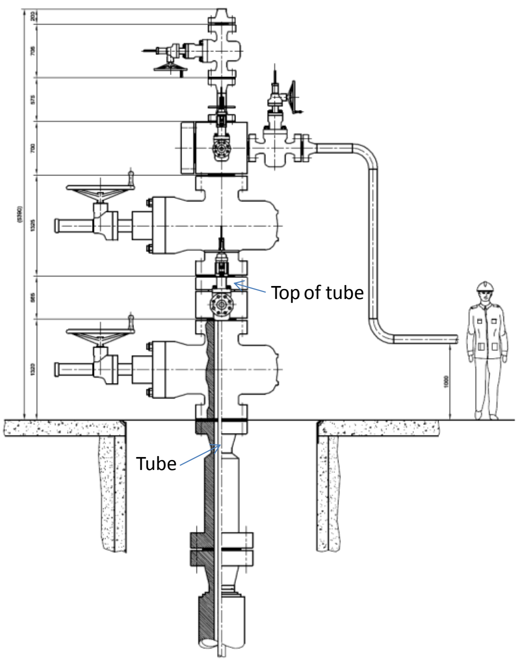

Figure 7: Possible utilization of a tubing solution similar to those used in the petroleum industry.

3.3 IDDP-2 Casing Design

The IDDP-2 design had to have fewer casings down to the 5000 m depth than IDDP-1, to fit the casings programs of the nearby wells. The following is a further explanation of the casing program design. Note that the cementing is explained in section 4 and this design is also highly dependent on the cementing and backup methods.

3.3.1 Surface Casing

Analysis of drilling reports from previous wells showed a fissure with inflow at the neighboring wells at 90 m depth. Thus, the surface casing was set down to 110 m to cover this zone. If it is not covered with a casing when drilled then this zone shall be cemented to prevent an inflow in the next section. This inflow is expected to be at a depth of approximately 100 m in IDDP-2.

3.3.2 Intermediate Casing ø18⅝" 450 m

The intermediate casing is drilled down to 450 m below another loss zone encountered in neighboring wells. The float collar and cementing stab-in collar are set at a depth of 300 m due to collapse risk for the casing.

3.3.3 Anchor Casing ø13⅜" T95/K55 1200 m, Hydril 563

The Hydril 563 connection is chosen for being gas tight in compression and tension. The strength of the connection is about 88% of the pipe in tension and 100% in compression. This connection was also used on IDDP-1. The T95 Grade is chosen due to burst pressure at the well head. As explained previously the steel grades differ due to the burst pressure at the surface and temperature cycling at the lower part. Both the steel grades are kept to the same thickness in order to reduce the local stress increase which otherwise might be introduced in the production casing. By using the same thickness the casings can also be attached without a crossover, simplifying the operations.

A stage cementing window (see Figure 9) is positioned just below the intermediate casing shoe. The stage cementing window is intended as back-up and will not be needed if the expected loss zones, that are present in the neighboring wells, are encountered. If there are no loss of circulation (LOC) zones that may be used for the cementing, then the stage cementing window is used.

3.3.4 Production Casing, ø9⅝" K55 3000 m, BTC

The production casing will be set at 3000 m which is expected to be about 400 m below the loss zone and is in tight rock. A stage cementing window is positioned just below the intermediate casing shoe, to allow cementing up to the surface between the casings (see Figure 8).

Considerable LOC is expected while drilling through the current production zone between 2000-3000 m. Losses will be handled using plug cementing but the cement volume of each plug has to be kept to a minimum to avoid contamination of the production zone. The cementing will be performed using a cementing string having the lowest part made of fiber-composite. Cementing string of that design gave good results during the drilling of IDDP-1.

3.3.5 Production Liner, ø7" 3000 – 5000 m, BTC

The production liner will be set at 2970 m (about 30 m overlap) down to 5000 m total depth. The material grade of the liner is still being evaluated. Based on the experience from IDDP-1 it is likely that the liner will be subject to aggressive corrosion and the material grade should be selected accordingly. The top 200 m of the liner are to be unperforated to allow the fluid to mix properly and thus, not introducing any scaling or corrosion in the production casing.

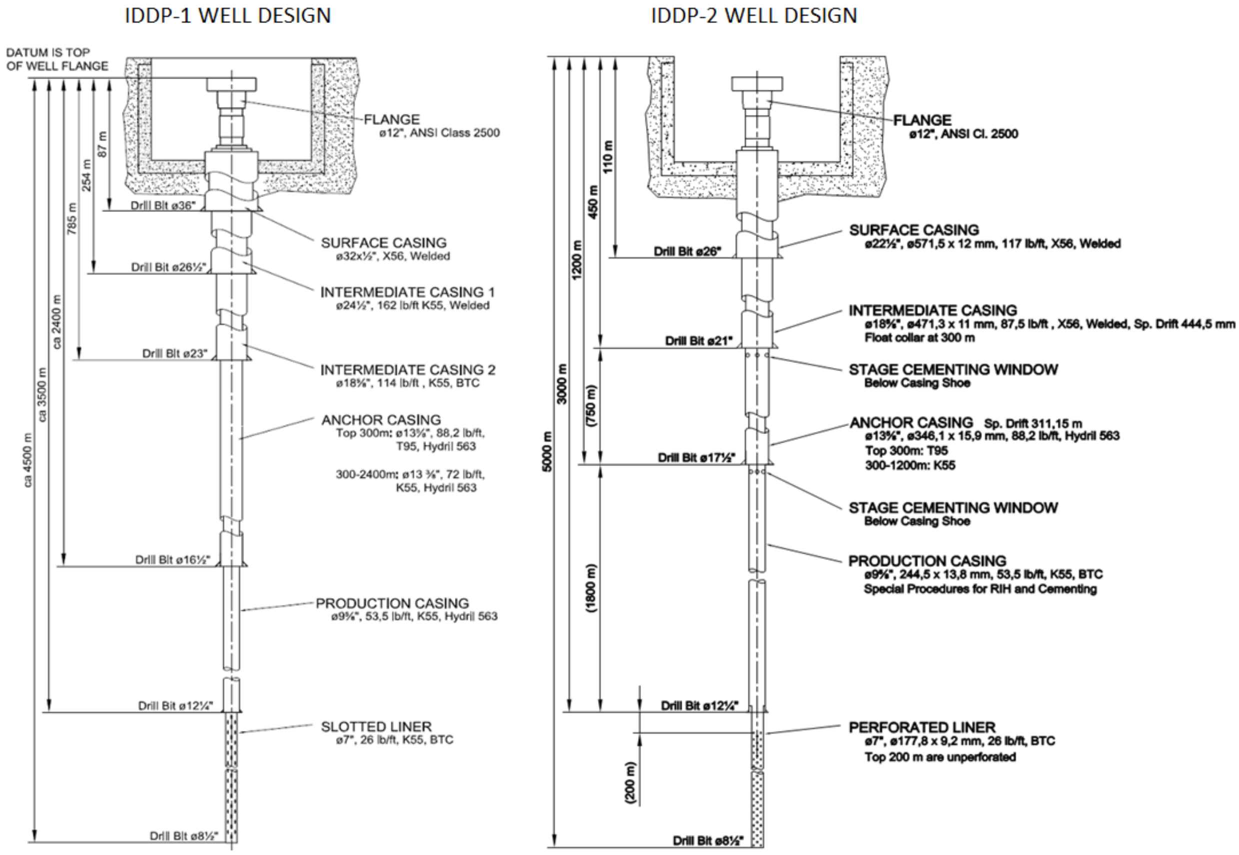

Figure 8: Comparison of the IDDP-1 and IDDP-2 casing designs.

4 CEMENTING

The cementing methods for the IDDP-2 casing have been chosen with the objective of being simple, with back-up procedures and minimize the warming up of the slurry during the cementing process due to expected high reservoir temperatures. Thus, the cementing procedures allow minimal contact with the hot formation.

The IDDP-2 casing program is shown in Figure 8. In appendix an overview of cementing methods that were considered for this design is presented.

4.1 Cementing methods

The cementing methods are listed for each casing interval. The cementing slurry is still being evaluated but the aim is to use Grade G cement mixed with silica powder (40% BWOC) and was used in the IDDP-1 design. The density is expected from 1.7 to 1.8 kg/l.

A cementing window is included in the anchor and production casings set just below the outer casings shoe. The cementing window and its operation are shown in Figure 9.

4.1.1 Surface Casing ø22½" 110 m

The objective of the cementing is to get good cementing in the annulus to surface.

The surface casing shall be cemented with a cement head for the calculated annulus volume and topped-off from surface if the cement does not reach surface.

4.1.2 Intermediate Casing ø18⅝" 450 m

The objective of the cementing is to get good cementing in the annulus from the shoe to surface. Estimated reservoir rock temperature at 450 m depth is 135° C.

The float collar and cementing stab-in collar are set at a depth of 300 m due to collapse risk for the casing. This increases the volume of concrete slurry by about 20 m^3 which will be left inside the bottom of the casing and drilled out. It is not advisable to push down with water to lower the cementing slurry left inside the casing because the float valve may fail.

4.1.3 Anchor Casing ø13⅝" T95/K55 1200 m, Hydril 563

The objective of the cementing is to get good cementing around the shoe and in-between casings.

A stage cementing window is positioned just below the intermediate casing shoe. The stage cementing window is intended as back-up and is not intended to be needed. If there are no LOC zones that may be used for the cementing, then the stage cementing window is utilized.

To get good cementing around the shoe, cement slurry is pumped down through stab-in and up the shoe annulus. The volume used is calculated for the highest LOC intended for use. After cementing, a temperature log is run to locate top of cement (TOC). There after it is cemented from the top down the annulus down to the LOC zone.

If the first cementing up from the shoe doesn't reach higher than 400 m, then it is advised to use the cementing stage window to cement down, and close the annulus at the same time to push the slurry down. After the required slurry volume the rest is flushed up the annulus with water, by opening the annulus, and then the annulus volume replaced with cement slurry in-between the casings. The cementing stage window is then closed.

4.1.4 Production Casing, ø9⅝" K55 3000 m, BTC

The objective of the cementing is to get good cementing around the shoe and in between casings. Estimated reservoir formation temperature is 362° C at the shoe.

A stage cementing window is positioned just below the anchor casing shoe.

To get good cementing around the shoe cement slurry is pumped down through stab in and up the shoe annulus. The volume used is calculated up to the highest LOC intended for use or the stage cementing window. After cementing a temperature log is run to locate TOC.

Then cement is pumped through the stage cementing window with a cementing head, while the annulus is closed to force the slurry down. After the required slurry volume has been pushed down or the slurry is frozen then the rest of the slurry is flushed with water to surface through the annulus by opening it. The remaining annulus volume is replaced with cement slurry to get good cementing in between the casing and then the casing cementing stage window is closed.

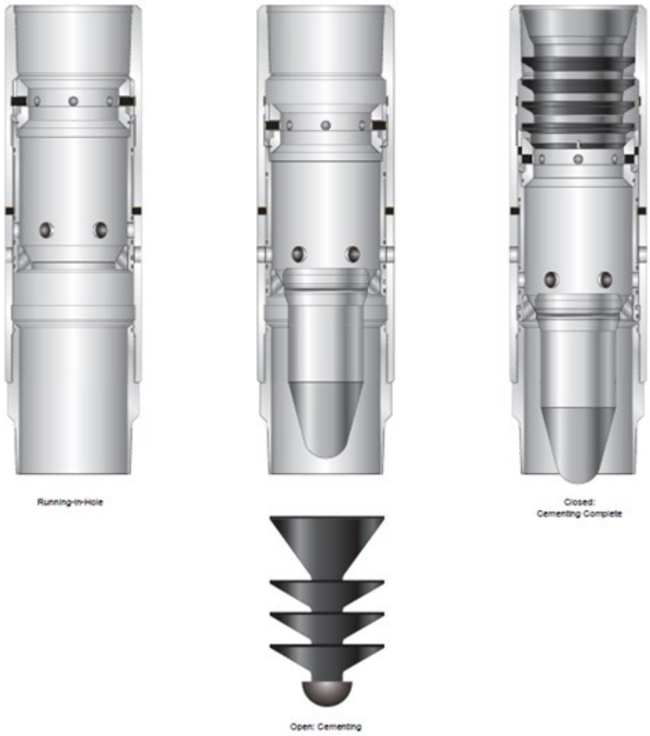

Figure 9: A cementing window is installed in the anchor- and production casing strings for backup in case of failure of the primary cementing method.

4. CONCLUSION

The IDDP-2 well design aims to provide a well capable of fulfilling the IDDP mission while being cost efficient, taking advantage of the lessons learned from drilling and operating the IDDP-1 well, and adapting to the conditions known in the geothermal field at Reykjanes.

The design of IDDP-2 is similar to IDDP-1 but with modification involving one less casing string, BTC couplings instead of Hydril 563 in the production casing, modification of casing thickness and review of material selection of the perforated liner. Cementing methods have been revised with the aim of adding contingency when cementing the casings.

The production casing in IDDP-1 failed when the well was quenched. The same will probably also happen in IDDP-2 although stress concentrations have been reduced. If in emergency the well must be killed a procedure using hot water will be considered.

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APPENDIX

MANNVIT

Overview of casing cementing methods

Cementing w. cementing head	+	Low cost: no plugs or collars required. Pressure within the casing can be maintained after cementing by sealing of the cementing head and thereby reducing collapse pressure at the bottom of the casing.
	-	Continued cementing is impossible if cement has not reached the surface after the decided quantity has been pumped into the well. No plugs are used which increases the risk of channeling and cement washout.
Plug cementing w. cementing head	+	Pressure within the casing can be maintained after cementing by sealing of the cementing head and thereby reducing collapse pressure at the bottom of the casing. The bottom cementing plug insures a good cementing front throughout the casing and the top cementing plug reduces the risk of channeling and the cement washing out. Cement displacement is more time consuming then when using inner string method.
	-	Continued cementing is impossible if cement has not reached the surface after the decided quantity has been pumped into the well.
Inner string cementing	+	Cementing can be continued if cement does not reach the surface when the decided quantity has been pumped into the well. The float collar can be placed at a considerable distance above the casing shoe to reduce collapse pressure at the bottom of the casing during cementing. Cement displacement takes a shorter time then when plug cementing is used.
	-	Cement remnants can be inside the cementing string after cementing operations(the cement can be flushed out with a dart).
Reverse circulation (RC) cementing	+	Can insure a good cement sheath between casings. Reduced effect of applied pumping pressure on formations. Less slurry exposure time to formation temperatures. Reduced WOC time.
	-	Hard tell if cement has reached the bottom of the well (some sort of dye can be used or radioactive material, complex cementing simulation programs are also used). Hard to ensure cement at casing shoe. All loss zones need to be plugged with cement during drilling for the casing.
Two stage cementing methods		With two stage cementing a suitible cement blend can be chosen for each stage (temperatures can vary greatly). Reduces continuous pumping time.
W. plugs and opening bomb	+	No temperature sensitive rubber connections. An annulus pakker can be placed below the stage collar and inside the outer casing, that ensures a cement sheath between the casings and to the top. Top of on first cementing stage possible.
	-	Water pocket can form if stage collar is above outer casing shoe.
Peak (C-Flex)	+	Continuous pumping possible in both stages (uses stab in in the first stage).Top of on first cementing stage possible.
	-	Has rubber for isolation that can melt due to high temperatures.
Use a Loss Zone for second cementing stage	+	Two stage cementing method. No unconventional cementing equipment necessary but two stage cementing equipment can be installaed in the casing string to keep options open.
		Risk of clogging Loss zones in first cementing stage. Can affect wells that are utilising the loss zone that is used for the second cement stage. Requires a conveniently located loss zone in the well.

MANNVIT

Overview of casing cementing methods

Two stage cementing		
Tie back		Usually used to isolate a casing string from excessive pressure loads due to production, continued drilling or if outer casing integrity is compromised. Is sometimes cemented.
	+	No temperature sensitive rubber connections. Tie back liner can be used as selected weakest point to reduce thermal cycling strains on other parts of the casing.
	-	Connecting Tie-back liner can be problematic because of possible cementing material debris from previous cementing operation. Tie back liner can sepparate from liner due to thermal cycling.
Lightweight cement		
Foam cement (addition of nitrogen)	+	Lightweight cement. Relatively high rheological properties. Has low permiability and relatively high compressive strength. More ductile than conventional cements. More resistant to cyclic loading than conventional nonfoamed cement systems. Can be suitible for LOC cementing (has the ability to expand). Has higher insulating capacity then conventional cements. Densities can be as low as 1,0 kg/dm. Has been used in geothermal wells.
	-	Expensive: Increased manpower and equipment during cementing. Complex execution. May require cap cementing from the top of the annulus after cementing. Special interpretation techniques required to properly evaluate bond logs. Increased risk of channeling. Longterm effect on cement in a geothermal production well not known.
Lightweight microspheres (LMS)	+	Lightweight cement, reduced WOC time, Provides the lowest permeability at a given density compared to other methods, Conventional mixing equipment can be utilized. Densities can be as low as 0,9 kg/dm3. Has been used in geothermal wells. Glass microspheres can counteraffect the cement strength reduction due to longterm high temperatures (+365° C).
	-	Expensive. Non-conventional cementing equipment may be required for very low densities. Requires more precise mixing than conventional cements (Conventional cementing units can be to imprecise). Rheology must be carefully controlloed to prevent the micro spheres from floating. Longterm effect on cement in a geothermal production well not known. Has limited pressure tolerance (weight increase with increased strength).
Add water (water extended)	+	Economical: Typically only a small amount of water extending materials are required to tie up the extra water.
	-	Dilution: Strength declines and permeability increases.
Cementing repairs		If a water pocket has formed or there is a long section that is uncemented the casing can be perforated with an explosive device either just to eliveate the pressure or for further cementing. If further cementing is needed then the hole is perforated in two areas and one of the areas isolated with packers and an opening in the string between them to squeeze the cement into the holes in the casing into the annulus and through the holes in the other perforated area of the casing.