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Iceland Deep Drilling Project: a Review of the Main Challenges and Implications of Drilling the Well IDDP-1

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Keywords

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ABSTRACT

The current work provides a historical overview of well IDDP-1, emphasizing its key design considerations, challenges and implications. Geothermal energy has witnessed significant growth globally, and Iceland is at the forefront of its development. The Iceland Deep Drilling Project (IDDP) was initiated in 2000 to explore the potential of developing deeper reservoirs with higher enthalpy potential by drilling into the supercritical zone. The IDDP-1 well, the first well drilled under this project with the aim of producing supercritical fluids, unexpectedly encountered a magma chamber at 2104m, leading to several challenges and ultimately the termination of drilling operations. Nevertheless, the IDDP-1 well was successfully put in production after setting a sacrificial casing. It discharged superheated steam at 450 °C, approaching an enthalpy of 3200 kJ/kg, thereby becoming the world's hottest geothermal well. The prevailing consensus is that a magma-EGS was created by fracturing the formation located just above the magma chamber. This work outlines lessons learned during drilling of the IDDP-1 well and addresses some development considerations of a magma-EGS in Krafla.

1. Introduction

Geothermal energy has been substantially growing in several regions of the world in the last decades. Iceland in particular has been one of the pioneers in extensively developing its geothermal resources, taking advantage of the abnormal geothermal gradients. Conventional developments have historically involved producing heated water and steam from reservoirs mostly shallower than 2km deep. Even though developing these assets has proved successful (these supply 30% of Iceland's total energy), opportunities have been explored to develop deeper reservoirs with higher enthalpy potential. This is how the Iceland Deep Drilling Project was created. (Friðleifsson et al., 2010).

The IDDP was founded in the year 2000 by a consortium of three Icelandic energy companies: Hitaveita Suðurnesja, Landsvirkjun and Orkuveita Reykjavíkur, and the National Energy Authority of Iceland. Its main purpose was, and still is, to study and sample fluids at supercritical conditions (Friðleifsson et al., 2010). The IDDP concept was born from the idea that, instead of drilling conventional geothermal wells that produce a mixture of steam and water, by drilling deeper it should be possible to reach the supercritical zone (400-600 °C). Supercritical geothermal fluids are considered by several authors as potential sources of high grade energy (Elders et al., 2010; Friðleifsson et al., 2010). These fluids, apart from possessing high enthalpy values, experience a significant increase in the ratio of buoyancy forces to viscous forces that can lead to extremely high rates of mass and energy transport (Elders et al., 2010).

The current work aims to provide a historical review of the IDDP-1 well, the first well drilled as part of the IDDP. It addresses its most significant design considerations, challenges and implications published in the available literature.

2. Discussion

2.1 Location overview

Three high-temperature geothermal fields in different locations in Iceland, at Reykjanes, Hengill, and Krafla, were selected to place the first well of the IDDP. The selection was based on the high temperature gradients exhibited in these fields, which implied supercritical conditions could potentially exist within 5km from the surface (Friðleifsson et al., 2010). After careful evaluation, Krafla, situated in the northern region of Iceland (refer to *Fig. 1*), was ultimately chosen as the location for drilling the IDDP-1 well. This decision was made following a proposal from the field operator to drill a 3.5 km deep well and subsequently deepen it to 4.5 km (Friðleifsson et al., 2010).

Inside Krafla, the main criteria specified by Friðleifsson et al. (2014) for site selection were high thermal gradients and high expected permeability. Elders et al. (2010) reported that volcanic eruptions occurred in this area decades ago. More specifically, a volcanic episode started in December 1975 and lasted for nine years. MT and micro-seismic surveys were carried in the field near the volcanic episodes that confirmed the existence of a magma chamber in Krafla, estimated to be up to a depth of about 2.5–3km (Friðleifsson et al., 2014). Based on the most favorable interpretation of the MT-survey, IDDP-1 site was located on what was interpreted to be the flank of the magma chamber, which would be potentially encountered at depths of at least 4km.

The selected location for the IDDP-1 was also based on the results of the nearby well KJ-36. Results from step rate tests done only one year before drilling in IDDP1 began, defined it as the most permeable well in the Krafla field at the time. It produced superheated steam, which was evidence for a high geothermal gradient. It was interpreted from these results that there would be a high probability of intersecting very permeable formations at the selected IDDP-1 site (Friðleifsson et al., 2014).

Site selection was also influenced by the existing regulations of drilling activity that imposed a limitation on the Krafla industrial area where geothermal development was, and still is, permitted, although only minor adjustments were made because of this (Friðleifsson et al., 2014).

Due to the existence of a magma chamber with limits that were not perfectly defined, there was a possibility of intersecting magma at shallower depths than expected in the IDDP-1. This concern gained strength after the well K-39, located in the same area as IDDP-1, intercepted volcanic glass just after drilling in IDDP-1 had begun. The concerns, however, were reduced by the well K-25, less than 100m away of IDDP-1 and of almost equal depth to K-39, which did not intersect magma nor encountered significant drilling problems (Friðleifsson et al., 2014; Pálsson et al., 2014).

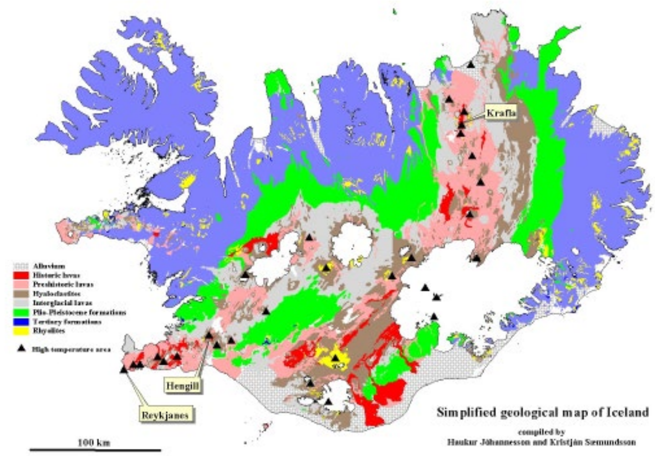

Fig. 1: Simplified geological map of Iceland showing the locations of the geothermal systems of Krafla, Reykjanes and Hengill (Friðleifsson et al., 2010)

2.2 Well design

The well IDDP-1 was designed following a basic set of premises. The well would be vertical, with a final depth between 4–5 km, and the design would aim to maximize the amount of scientific information that could be obtained on supercritical phenomena. Coring a section of the well where the fluid was found in supercritical conditions was considered critical to serve this purpose (Thórhallsson et al., 2014).

Temperature and pressure prediction in the well were sensitive aspects to consider throughout the design. Both parameters impact the determination of the number and depth of casing strings, casing strength, mud and cementing program, among other design premises. The generic model for casing design assumed the highest possible temperature profile vs. depth, which followed the boiling point-depth curve to the critical point at 3500m. The boiling point depth curve (BPD) is a commonly used technique in designing geothermal wells. It consists in specifying boiling temperature of water or brine at different pressure values that are converted to depth (Cultrera, M., 2016). Temperature gradients observed from previous drilling to 2000–2900m of 55 production wells at three sites in Iceland typically followed the BPD curve from about 1100 m downwards (refer to *Fig. 2a*). This suggests that the critical point for pure water should be reached at depths of about 3.5 km. Below the critical point depth, the temperature would no longer be confined by the saturation conditions. A set of gradients that ranged between an isothermal condition up to 100°C/km were considered. This meant that the temperature at 5000m could be either 390 ◦C or 550◦C (Thórhallsson et al., 2014). However, the possibility of reaching temperature conditions higher than that controlled by the BPD-curve at shallower depths was also possible. For instance, the temperatures in well NJ-11 at Nesjavellir (Elders et al., 2010) surpassed the conditions determined by the BPD curve, as superheated steam hotter than >380°C was encountered at 2200 m depth. f

The pressure model assumed a hydrostatic column of water down to the depth of the critical point. Below the critical point, the density is assumed to behave as an isochor, which means that density changes are calculated based on pressure changes corresponding to temperature variations assuming a constant steam volume. As the steam from the IDDP well could prove to be rich in H2S, the casing selected had to be resistant to sulfide stress cracking. The strain to which the casings would be subject because of the heating and cooling was also considered (Thórhallsson et al., 2014).

As mentioned previously, coring a section of the well in supercritical conditions was one of the main objectives of IDDP-1. The coring equipment was therefore designed to resist the high temperatures expected. Projected temperatures in the IDDP borehole before cooling were expected to be as high as 500°C. Since the coring assembly could only resist up to 250°C, cooling of the well would be required. A core barrel was selected that had the unique feature to enable high water flow rates for cooling during coring (Skinner et al., 2010). It was estimated that a minimum flushing capacity of 30-40 liters per second would have to be maintained for the whole tripping time and preferably for at least some of the coring time. A digital temperature probe was placed in a pressure housing at the top of the inner barrel core chamber to record temperature during coring (Skinner et al., 2010).

Larger casing diameters were used compared to previous conventional geothermal wells in Krafla that mostly reached depths up to 2500m. The final well design consisted of five cemented casings strings with a final diameter of 8 ½" for the open hole and 7" for the slotted liner. These larger diameters allowed for higher flow rates that improved the cooling of the well. A larger diameter would also ease the process of collecting the core (Thórhallsson et al., 2014). The coring system selected was non-wireline with an outer diameter of 7¼", capable of collecting a 4" diameter core using an 8½" OD core bit (Skinner et al., 2010).

The top part of the anchor casing, which preceded the production casing, was designed for creep and rupture conditions, following the standards provided in the ASME Boiler and Pressure Vessel Code for creep and rupture design. The top part would not be firmly cemented and was designed to withstand the internal pressure and temperature expected at the wellhead. Therefore, the top 300m of the anchor casing was made of grade API T-95, which provided the needed creep resistance (Thórhallsson et al., 2014).

The portions of the anchor and the production casing that would be cemented had to be able to withstand the strain that results from heating and cooling of the well, presented in *Fig. 2b*. Grade K-55 was evaluated as compliant and was therefore selected. The yield strain of this steel is higher than other conventional casing grades and is less susceptible to cracking (Thórhallsson et al., 2014).

Buttress thread couplings were selected as the casing connections of the shallower sections. Although these possess high tensile strength, their compressive strength is considerably lower. Observations also indicated that buttress connections had been susceptible to leaking when the temperature exceeded 200°C (Thórhallsson et al., 2014). Based on this, Hydril 563 connections were utilized for the anchor and the production casings, were conditions would be the most extreme. These withstand an axial load that exceeds the load capacity of the casing itself, both in tension and compression. Tests carried out on these couplings by the manufacturer also showed good resistance to thermal expansion of the cemented casing with temperatures up to 343 °C (Thórhallsson et al., 2014).

Both the casing head and the wellhead were designed to be clad with a stainless steel (SS 309) welded overlay to make them more corrosion resistant. This decision was taken after the well KJ-36, located near the IDDP-1, showed high concentrations of HCl and H_2S gas that lead to the corrosion of surface equipment (Elders et al., 2010; Friðleifsson et al., 2014). The wellhead was also designed to resist a maximum temperature of 470 ◦C and a maximum shut-in pressure of 22 MPa (Thórhallsson et al., 2014).

The well would be drilled with conventional tri-cone insert bits, deemed as successful at drilling previous wells in Krafla. Bentonite mud would be used in the portion of the well with larger diameters up to 2400 m. Below this depth, the drilling fluid would be switched to water with the occasional use of high-viscosity polymer pills for well cleaning. The reasons behind this design were not explained in previous works. Extra mud-cooling capacity would be added by use of a cooling tower. To increase the rate of penetration, mud motors were specified for use in certain parts of the well. The defined policy to act in front of circulation losses consisted in sealing loss zones with LCM when losses were lower than 5–10 lts/s. The zones would be cemented if losses exceeded this limit.

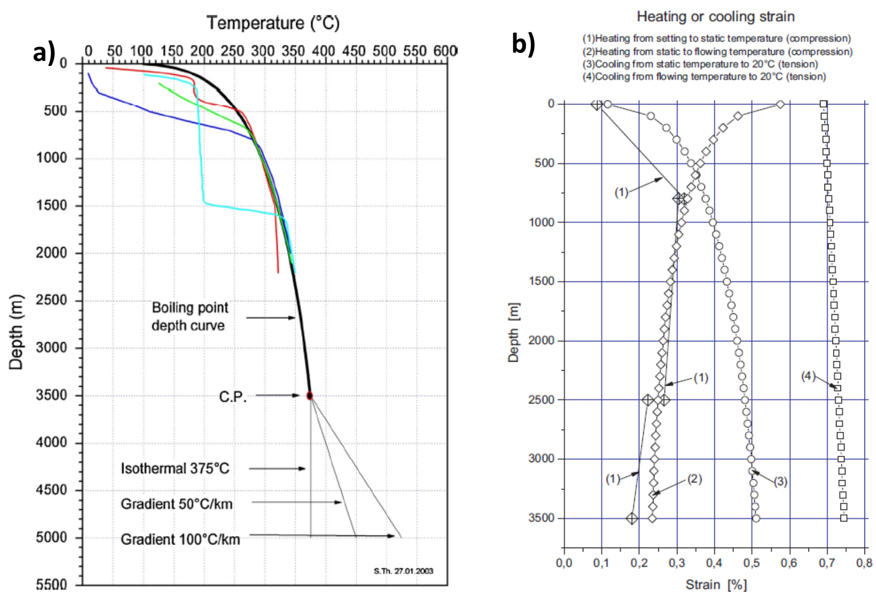

Fig. 2: (a) Temperature gradient assumed in the IDDP well. The graphed lines are formation temperatures that approach the BPD curve (black line). (b) Strain to which the casing will be subject because of heating and cooling. (Thórhallsson et al., 2014)

2.3 Review of drilling operations

Pálsson et al. (2014) provided a detailed description of the drilling operations. In this section, a brief overview is introduced and some of the most critical challenges encountered are discussed.

Drilling of IDDP-1 began in June 2008 and it progressed without upsets during the initial sections of the well. The first three sections were cased down at 87m, 254m and 788m, respectively. *Fig. 3* presents a complete description of the well casing tally.

Drilling of the anchor casing section commenced on March 24th with a ø16-½ roller cone tricone bit and a ø9-½ mud motor with a sleeve. Several issues were faced while drilling this portion of the well, including circulation losses, stuck pipe, fishing operations and wellbore cleanout problems, which are discussed in detail in the next section. Despite this, it was possible to drill the well down to 2000m, where complete loss of circulation occurred. This led to stuck pipe problems and two fishing operations. Since the second fish could not be retrieved, it was decided to cement the bottom of the hole and do a side-track. Placement of the cement plug and the side-track were successful, but it was decided to change the design of the well due to the harsh conditions. The anchor casing shoe was then set at 2000m instead of the 2400m initially designed.

Drilling continued and once the drill string reached 2076m after a series of issues which specially involved circulation losses, the string was stuck again. Fishing operations were attempted with unsuccessful results and resulted in a second side-track. After drilling re-commenced, the drill string became stuck once again at 2096m. Abundant cuttings of quenched glass returned that indicated that the well had drilled across magma. Interestingly, no smell of H_2S gas was detected and no damage could be seen on the bit or on other parts of the BHA. Further drilling into the magma was considered not feasible. *Fig. 4* shows the drilling progress diagram for the IDDP-1 well.

After terminating drilling operations, it was decided to attempt to produce from the well. To further secure it, a 9 5/8” production casing was installed down to 1935m as a sacrificial casing due to possible acidic fluid. A 9 5/8” slotted liner was placed from the production casing shoe to 2072m to maintain the wellbore open for flow. The cementing operation was done with reverse cementing in two stages. Top and bottom of cement in the first stage were registered at 725m and 1700 m respectively by a CBL log. Then, the annulus was back-filled to surface. This procedure will be meaningful when discussing the IDDP-1 failure during flow testing below.

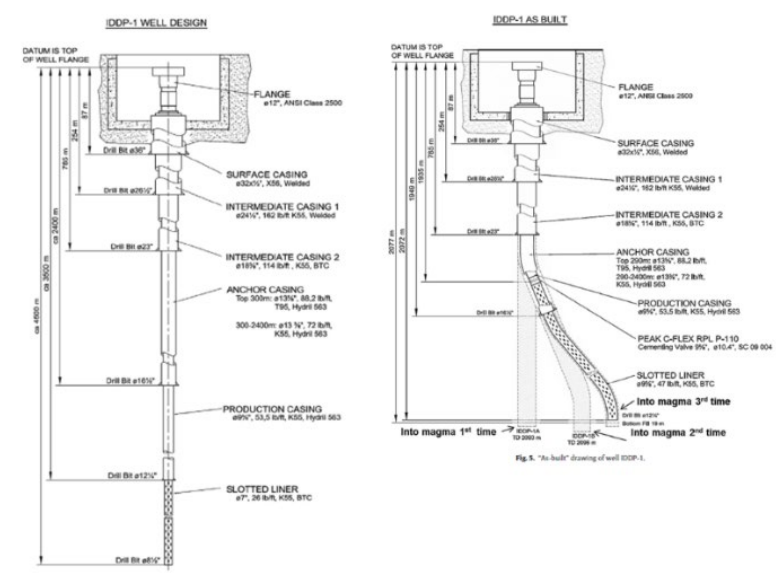

Fig. 3: Original design of the IDDP-1 (left) and the IDDP-1 as built (right) (adapted from Pálsson et al. (2014) and Friðleifsson et al. (2015))

2.3.1 Challenges during drilling

Some of the main challenges encountered during drilling of the IDDP-1 are discussed in this section:

2.3.1.1 Lost circulation

Several losses were detected while drilling the IDDP-1 at multiple depths. In all cases, the strategies reported to control circulation losses refer to either pumping LCM (lost circulation material) or cementing the zone if losses were too severe. Some of the main episodes are detailed as follows:

● *Intermediate II + Anchor*

While drilling the intermediate section II above 785m, minor losses were detected and healed by pumping LCM. More severe losses of 20 lts/s were also detected at 1432m while drilling the anchor casing section. At that point, a decision was made to cement off the loss zone to minimize the mud losses and to prevent interflow between loss zones during the casing procedure.

A decision was made to modify the well design and set the anchor casing at a depth of 2000 m instead of the intended 2400 m, as previously noted. Because of known losses in certain portions of the well, it was planned to perform two-stage cementing, consisting of a string job up to the loss zone at 1600m and back-fill up to surface through the kill-line. After the first stage, a cement bond log (CBL) indicated the top of cement at 1600m as planned. After the second cement job, CBL and temperature logs showed the top of cement at 100 m depth and no cement was in the annulus from 1410m and down to 1600m. The missing cement seemed to have entered the feed zone at 1432m that was previously cemented to control losses (Pálsson et al., 2014).

Losses in this portion of the well can be explained by the presence of two conventional hydrothermal reservoirs between 1400m and 2000m. These are conventional targets of geothermal wells near the IDDP-1 with temperatures above ~170 °C (Friðleifsson et al., 2015). Circulation losses may be related to induced fracturing by thermal or hydraulic cracking due to the long cold mud column during drilling. These losses could also be explained by naturally open fractures in the formation, which have been previously observed in drill core samples from nearby wells (Friðleifsson et al., 2021).

● *Production*

The section between 2016 m and 2076 m, just above the magma chamber, involved multiple episodes of total loss circulation. The first time occurred after the string reached 2043 m, when losses of over 60 lts/s could not be healed and resulted in stuck BHA that could not be retrieved. This led to the first side track and a decision to change the anchor shoe depth from the initially designed 2400m to 2000m.

The second time the string reached 2016m, after cementing the anchor casing and rotating the cement completely, circulation was totally lost again (above 50 lts/s). Now, the countermeasure adopted was placing a cement plug from 1957m to the bottom. This reduced the amount of lost circulated fluid and permitted to drill down to 2040m for a second time, where total losses restarted. A new attempt to stabilize the well was made by placing a cement plug, with top of cement at 1970m. The cement was drilled out and circulation losses became intermittent from 2067m, until complete loss of circulation occurred once again at 2076m. This resulted in a stuck BHA and a second side-track. Once the well was drilled again down to 2071 in the new side-track, severe losses re-started. At this time, abundant cutting of quenched glass were retrieved that identified the magma chamber (Pálsson et al., 2014).

Complete circulation loss events occurring between 2006 m and 2076 m were observed to cause a significant increase in torque and stuck pipe issues. Two times the stuck BHA could not be retrieved, leaving a fish in the hole. On both occasions, a cement plug was placed and a side-track was necessary. It was later found out that these circulation losses were associated with coming across a formation that was located just on top of a magma chamber (Pálsson et al., 2014). Schiffman et al. (2014) identified this formation as a metamorphosed conductive boundary layer that acted as a thermal "link" with the rhyolite magma. Being a metamorphic rock that should intrinsically have low permeability, hydrofracking by cold water circulation during drilling was suggested by Friðleifsson et al. (2015) as the most likely scenario to explain the total circulation losses in this zone. Different authors also discuss the possibility that the hard rock in the metamorphic aureole above the magma, with ambient temperatures close to 500°C, was actually thermally fractured by the drilling fluid (Pálsson et al., 2014, Mortensen et al., 2014, Schiffman et al., 2014).

2.3.1.2 Hole cleaning

Pálsson et al. (2014) reported several complications associated with hole cleaning. The strategy selected to mitigate this problem consisted mostly in pumping viscous pills. No references were found related to the designed flow rate. The main episodes involving unsuccessful cleaning can be summarized as follows:

At a depth of 1930 m, multiple losses of circulation led to unstable conditions that complicated hole cleaning. Evidence of poor hole cleaning was observed through the presence of bottom-hole cutting fillings that were up to 40 m thick after fluid losses during the first side-track (Pálsson et al., 2014).

Additional complications arose after the well reached 2005 m with a 16½" bit during the first side-track. At this point, the anchor casing was cemented with an outer diameter of 13 5/8", and its shoe was set at 1935 m. Subsequently, the section between 1935 m and 2005 m remained with a diameter of 16½" and a thick bed of cuttings lied at the bottom of the well. Drilling was resumed with a 12¼" bit and the resulting large annulus area caused slower mud velocities and weaker drag force, which complicated hole cleaning (Pálsson et al., 2014). High viscous pills were used to reinforce hole cleaning with a relatively low ROP and a high pumping rate. This process was repeated every 3 meters of drilling until the bottom of the well was reached at 2005 m. Cleaning by circulation was described as time-consuming and challenging. Several high viscous pills were pumped while the string was carried down to the bottom after placing a cement plug between 2002 m and 2060 m to mitigate circulation losses.

High viscous pills were pumped again on every single after reaching 2070 m during the second side-track due to poor wellbore cleaning (Pálsson et al., 2014).

It is suspected that poor hole cleaning before entering the loss zone at the bottom could have been responsible for the stuck pipe problems previously mentioned. Remaining cuttings inside the well probably sank as fluid was being lost into the formation. These probably accumulated in the annulus at the bottom of the well, which led to the pipe getting stuck in several occasions.

2.3.1.3 Hard formation

Pálsson et al. (2014) repeatedly noted the slow ROP values observed while drilling as a consequence of drilling across multiple hard formations throughout the entire hole. This problem was first reported while drilling the intermediate casing. Drilling was described as slow with an average ROP of 2.5 m/hr because of hard formation. At 1432m depth, Pálsson et al. (2014) reported that the bit was pulled out of the hole and was found in a surprisingly bad condition after only 47m of drilling. At 1907 m, ROP was again reported as slow due to hard formation.

Unsuccessful coring of the well was also thought to be at least partially (if not completely) the consequence of coming across a hard formation. The coring operation took place in an identified fractured zone at 2040m depth. It was intended to collect a 9 m spot core, but after only drilling 2 meters in 3½ hours the drill string had to be pulled out for inspection. Pálsson et al. (2014) described the core bit as completely worn down, with inserts of the core barrel stabilizers broken off and the surface of the barrel completely marred. No core was found in the barrel and the core catcher had been pressed approximately 70cm up (Pálsson et al., 2014).

This can be mostly explained by the lithology of the stratigraphic column. This was studied in the IDDP-1 well through drill cuttings collected at 2 m intervals, and by down-hole geophysical logs (Mortensen et al. 2014). The stratigraphy was understood to be mainly comprised of basaltic lavas and hyaloclastite sequences extending down to 1,362 m, succeeded by an intrusive complex. The intrusive rock intensity reaches up to 40–50% of the stratigraphic column in most wells located within this geothermal field at similar depth. Apart from intersecting magma, the stratigraphy of the IDDP-1 is similar to that of neighboring wells (Friðleifsson et al., 2014).

Millet et al. (2016) noted that average ROP through basaltic sequences has been historically very low mainly because of the hardness and high abrasiveness of basalt. The high content of basaltic and intrusive rocks would therefore explain the slow rates of penetration experienced, and it would also be responsible for the observed damage in the bit and core assemblies.

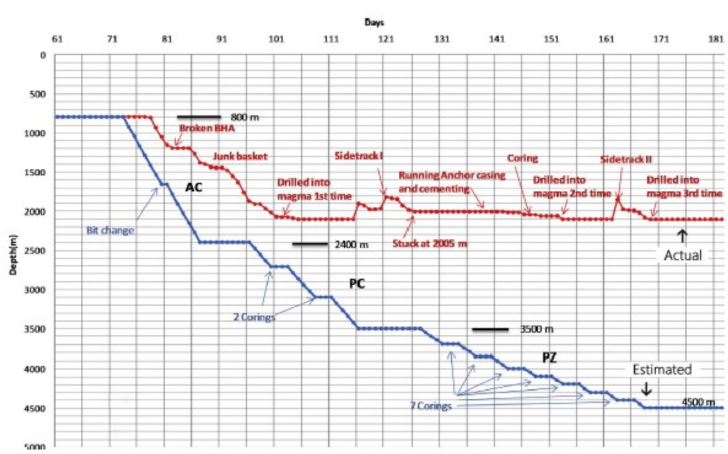

Fig. 4: Driling progress diagram for well IDDP-1 (Pálsson et al., 2014)

2.4 Injectivity and productivity results

The injectivity of IDDP-1 was tested in June 2009, after cementing the production casing, and did not provide groundbreaking results. Injection lasted for 4 weeks before the well was shut-in for temperature recovery (Pálsson et al., 2014). Initially, the injectivity index was close to 15 (lts/s)/bar, being the largest recorded in Krafla at the time, but it later decreased to more conventional values of 2.5 (lts/s)/bar.

Subsequently, after 7 months of thermal recovery in the shut-in well, production tests began in March 2010. The well was discharged during five successive time intervals. The first stage showed a mixture of water and steam, and no superheated fluid. The steam produced contained 100 mg/kg HCl gas and gaseous sulfur which formed hydrochloric acid and sulfuric acid respectively upon steam condensation. This provided a highly corrosive environment that jeopardized casing and wellhead integrity. Although this made the steam unfavorable for direct use, surface equipment was adapted to allow the generation of pure steam by scrubbing the produced steam with brine at surface. During the second stage and thereafter, the steam became superheated and no longer posed a threat to casing integrity during production, even though condensation of the steam remained corrosive and affected surface equipment. Successive shut-ins and re-openings took place afterwards due to re-adaptations of surface equipment after episodes of orifice erosion, orifice blockage by corroded debris coming from the sacrificial casing in the bottom and pipe vibration. During shut-ins, the casing suffered from thermal strain due to cooling and was exposed to corrosion because of steam condensation. During the last test, which started in September 2011, the well continued discharging superheated steam (steam heated above boiling point) at 450 °C and enthalpy approached 3200 kJ/kg. A maximum flow of 50 kg/s of superheated steam at 40 bar was measured (Ingason et al., 2014; Friðleifsson et al., 2015) during the test. These high enthalpy values are consistent with the estimated temperature of 500°C of the metamorphic rock at the bottom of the well acting as conductive boundary layer supplying heat magma chamber to the overlying hydrothermal system (Friðleifsson et al., 2015). This layer, composed mainly of mafic granoblastic rocks, is believed to be heated by the magma chamber that lies underneath, where temperature was estimated to be around 900°C based on a mineralogy study of cuttings retrieved (Schiffman et al., 2014). Production tests indicate the well IDDP-1 was capable of producing up to 36 MWe depending on the design of the turbine system. Since the steam was also in superheated condition, which makes it reactively inert, corrosion in the casing was not considered of concern during this stage (Ingason et al., 2014; Friðleifsson et al., 2015; Friðleifsson et al., 2021).

During production, a tracer test was carried out. This is worth mentioning due to its importance for understanding the origin of the produced fluid. Tracers were injected into three wells, K-26, K-39 and IDDP-1. The IDDP-1 tracer was retrieved in only one well, K-36. The most plausible explanation is that it entered into K-36 through the 1,600 m feed zone, as the bottom section and deeper feed zones in this well had earlier been sealed off by cement (Friðleifsson et al., 2015). This detection indicated a connection between the deeper metamorphic aureole contacted in IDDP-1 and shallower geothermal reservoirs. This would mean that a fluid at BPD conditions within the shallower two phase reservoir flowed downwards and was heated by around 100°C from ~350 °C to 450 °C by the metamorphic aureole before entering the IDDP-1. Friðleifsson et al. (2015) suggested that this connection was originated by thermally cracking and hydrofracking the rock after pumping cold water into the hole.

During the flow test of IDDP-1, several fluid samples were extracted and their composition was analyzed (Ármannsson et al., 2014). The first collected samples involved a combination of water, condensate and steam and showed erratic behavior in their chemical composition, with abrupt changes in the concentration of some components. Since 2011, the IDDP-1 well produced superheated steam, and samples began showing more stable compositions through time. The fluid produced in these last samples in IDDP-1 shared similarities with the superheated steam encountered in well K36. Their pH is similar (2.4 – 3.4 at 22°C in IDDP vs 3.3 at 21°C in K36), CO_2 contents are lower than other wells drilled in Krafla (e.g. K12, K34) and F contents are higher. Although their F contents are also very similar (~ 8mg/kg), some differences can be pointed out as well. Concentration of Cl in K-36 is 3 times higher than in IDDP-1 and it evidenced larger content of CO_2 (>6400mg/kg in K36vs ~500 mg/kg in IDDP1). The proximity in IDDP-1 to the magmatic environment could explain their differences in composition. However, the low CO_2 concentration exhibited in IDDP-1, which is usually associated with magmatic activity, was not expected and could be regarded as additional evidence of fluid flow from shallower feed zones.

Flow tests ended in 2012 when the IDDP-1 well had to be cooled down rather abruptly due to leakage in a nozzle at surface, probably as a consequence of the condensation of the acid concentrated steam (Ingason et al., 2014) and surface valve failures. Ingason et al. (2014) noted that the differential thermal expansion of the hot gate compared to the cold inner body of the valve was probably the reason behind repeated difficulties in opening the valves, even though this same type of valves had proved to be successful in several other geothermal wells in Iceland in the past. Despite slow and careful injection of cooled fluid, the thermal strain on the 450 °C hot sacrificial casing was too severe. The casing snapped apart at least at two depth levels above 600 m, which is the approximate depth of the intersection between the two cementing operations in the production casing (Pálsson et al., 2014; Friðleifsson et al., 2015).

In early 2016, parts of the IDDP-1 wellhead were retrieved to analyze the integrity of the material after being exposed to such harsh conditions. Temperature was recorded to be as high as 452°C with pressure of 144 bar. Pieces from the anchor casing and production casings were studied in detail. The grade of the anchor casing was T95, which is a Cr-Mo low-alloyed steel with low carbon content; while grade K55 was used for the production, which contained no Cr or Mo but had a higher carbon content. Grade T95 showed only minor corrosion and no signs of hydrogen cracking, although corrosion pits were detected on the inner surface. Its mechanical properties, such as tensile strength and yield strength were not significantly affected. The production casing pieces, however, showed significant detriment in their mechanical properties, where tensile and yield strength fell below the minimum standards. Thorbjornsson et al. (2020) concluded that the K55 grade had been significantly corroded due to a phenomenon previously unidentified which they cataloged as high temperature hydrogen attack (HTHA). This process consists in severe intergranular cracking as a consequence of the diffusion of atomic hydrogen produced in the corrosion process into the steel structure, where the hydrogen binds to carbon and forms methane gas. Severe cracking was observed on the material’s surface because of this. Sulfide stress cracking (SSC) was also reported to take place due to the low pH environment to which the material was exposed when the fluid condensed (Thorbjornsson et al., 2020). Severe and deep pitting corrosion was also reported.

3. Design challenges and considerations

This section addresses some of the main design challenges that should be considered in the development of the magma-EGS system in Krafla.

3.1 Casing and wellhead materials

According to Thórhallsson et al. (2014), K55 grade was selected for the production casing accounting for the induced thermal strain that the pipe would suffer during cooling from 450 °C (temperature was projected to be between 390°C and 550°C) to 20°C, and it was presumed to resist it. As experience in IDDP-1 showed, this was not the case and the production casing collapsed during cooling. Therefore, casings and couplings would have to be redesigned considering the high strains derived from the large temperature difference from cooling and heating cycles taking place in the well. Considering the bottom-hole temperature registered in IDDP-1, temperature variations of at least 400°C could be expected. Wellhead and surface facilities would also need to be conditioned for temperature values exceeding 500°C.

Casing failure is probably the biggest challenge to consider when designing a super-hot geothermal well. When subjected to the high temperatures inherent to the production stage, the casing material suffers thermal expansion. Such expansion results in additional compressive stress applied to the casing constrained by the cement. If the compressive yield strength of the steel is exceeded, then compressive failure may occur. The casing undergoes the opposite effect in the case of cooling. It will thermally contract and tensile stress will be applied to the casing constrained by cement (Kang et al., 2022). The magnitude of expansion or shrinkage, depending on the case, can be described by the induced thermal strain, defined in *Eq. 1*:

$$\varepsilon_t = \alpha\ (T_f - T_i) \qquad \text{Eq. 1}$$

Cyclic thermal loading is an additional failure mechanism that can affect the casing. It consists of a sequence of heating and cooling of the material. A geothermal well experiences heating during the production phase, and can experience subsequent cooling when the well is killed by the injection of cold fluid. *Fig. 5a* shows the stress-strain curve of a generic failure case by cyclic thermal loading. If the casing is heated up to point C, which is past point B (yield strength point), then plastic deformation has taken place and the path B-C is not reversible. In case the material is then cooled, if the tensile stress exceeds the yield strength, then tensile failure will occur, either by thread pull out at a joint or by casing fracture at a weak point (Kang et al., 2022).

This failure mechanism is what led the IDDP-1 casing to fail during cooling of the well when the surface valves failed. Skulason et al. (2016) modeled the thermal stress-strain cycles in IDDP-1 well during flow periods and shut-ins (refer to *Fig. 5b*). Compression and tensile stages can be observed alternatively throughout the entire production period. The authors noted that plastic compressive strain was produced in each stage from the beginning, while plastic tensile strain was produced at the second to last stage. High tensile stress originated during quenching when the casing failed (Skulason et al., 2016).

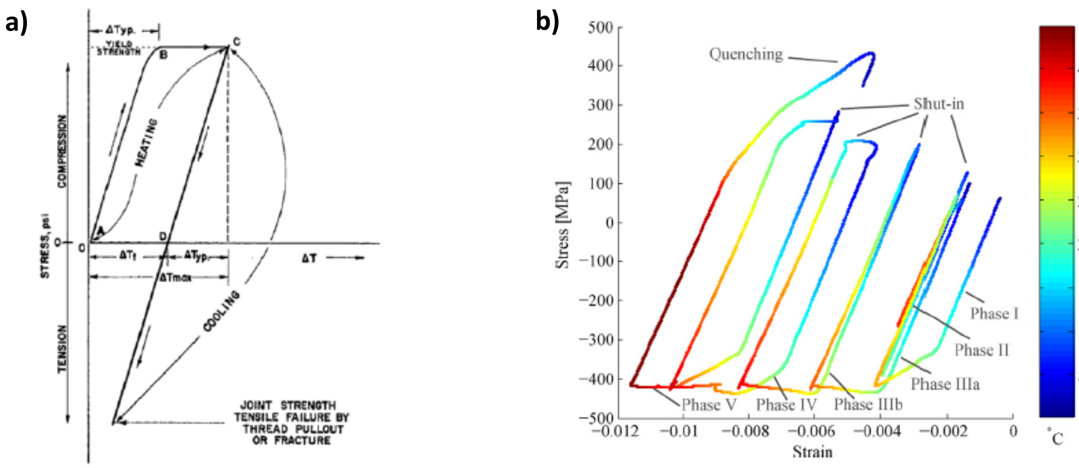

Fig. 5: (a) Generic stress-strain curve at a heating and cooling cycle (Willhite et al., 1967); (b) Stress-strain cycles modeled for the production casing in IDDP-1 at 50m depth (Skulason et al., 2016)

During quelching of the well a temperature difference of approximately 430°C was applied at the casing. Final temperature during cooling operation is not reported but it is most likely around 20°C, which is the cool water temperature during the pre-flow injection test (refer to *Fig. 6*); and the initial temperature is adopted from the production test, where flowing temperature was declared to be 450°C when the well was closed (Ingason et al., 2014).

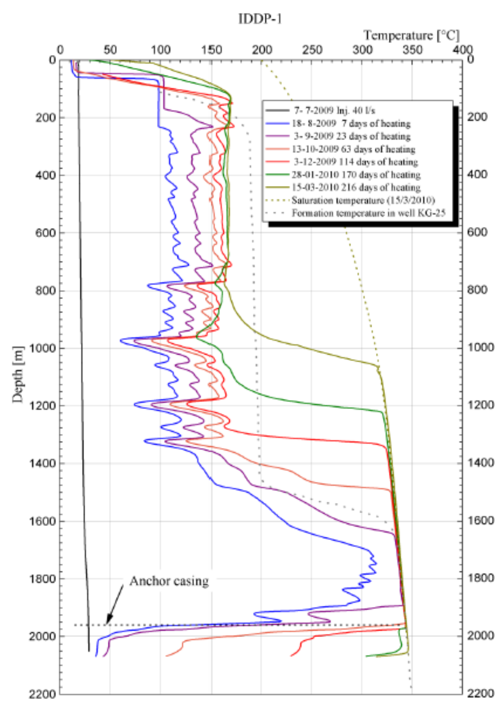

Fig. 6: Temperature log in IDDP-1 during and post-injection (Friðleifsson et al., 2015)

Gruben et al. (2021) carried out a series of tests of different casing materials and showed a decrease in carbon steels' yield and tensile strength by approximately 60% as general trend when subjected to superhot temperatures (550°C). In particular, casing grade K55, which is the same as the production casing in the IDDP-1 well, was tested. The results indicated a reduction in tensile strength to 45% of the capacity at room temperature (refer to *Fig. 7*). This would further validate that the tensile thermal stress induced by the cement on the casing exceeded the tensile strength of the material when the casing collapsed. It would also introduce the possibility that casing failure would have occurred during the cooling operation regardless of the induced plastic strains from previous thermal stress cycles.

The tests run by Gruben et al. (2021) also indicated that alloys with high nickel content showed better results at high temperatures than carbon steels and retained their original strength at temperatures above 350°C, although the samples displayed dynamic strain ageing that can accelerate the deterioration of the material under low cycle fatigue (Gruben et al., 2021). Titanium alloys were also tested and showed both high strength at 500°C and no dynamic strain ageing which made them good candidates for superhot wells according to the authors. Further research on the topic is needed, but the design of an alloy to withstand the large thermal strains, cycling and corrosion is crucial to cruise into a magma-EGS development.

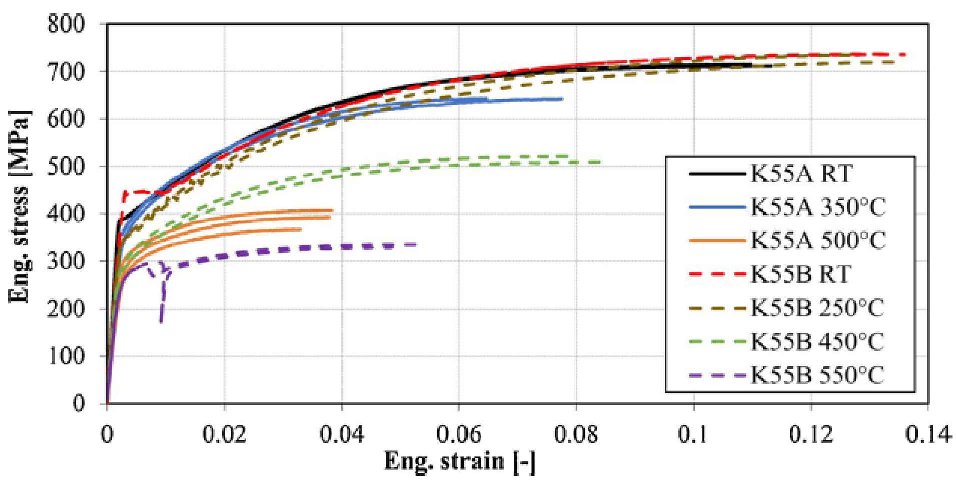

Fig. 7: Stress-strain curves from tensile tests on two samples with K55 steel grade at different temperatures (Gruben et al., 2021)

An additional critical element that can lead to failure is cement integrity at high temperatures. Even if cement shows adequate behavior at early stages of setting, it may lose its strength after continuous exposure to high temperatures (Allahvirdizadeh, 2020). If cement is not intact and properly bonded, the likelihood of casing failure increases.

3.2 Circulation losses during drilling

A major challenge is redesigning the drilling strategy near the magma chamber contacted in IDDP-1 well. It was observed that contacting the metamorphic aureole led to total circulation losses that derived multiple times in poor cuttings cleaning resulting in stuck pipe. Improving hole cleaning before drilling into the magma chamber would be recommended. Circulating mud with a steady pipe to remove all remaining cuttings inside the well before entering the expected loss zone could prevent stuck pipe problems afterwards.

The strategy for handling loss of circulation was based mostly on pumping LCM or placing cement when the losses were too severe. This is a common practice in drilling geothermal wells (Finger et al., 2010; Nugroho et al., 2017). However, Saleh et al. (2020) noted that some LCM start degrading at lower temperatures (<100°C) while others have stronger resistance. Considering the vast experience of the operator in the area, it is assumed that the LCM used in the upper formations (1400m-1600m) was probably stable. However, it is unknown whether the LCM pumped in the metamorphic formation at 500°C was resistant enough. The severe losses experienced proved that the LCM was unsuccessful in this zone. There are several possible explanations for this, like a fracture width too large to be sealed, but LCM degrading is worth to be considered when defining how to drill through loss circulation zones.

Since LCMs were not successful and since fracturing due to induced thermal stress in the rock could prove to be inevitable, a potential strategy that might be worth analyzing for drilling into the metamorphic aureole could be “blind drilling”. This method involves continuous injection of sacrificial fluid through the drill pipe and the annulus without return. This would at least maintain a certain pressure in the well that could help to prevent wellbore stability problems. Cuttings would not return to surface and would be dragged into the formation, possibly aiding in blocking high-permeability channels (Nugroho et al., 2017). Nugroho et al. (2017) recommended pumping high-viscosity sweeps every given amount of meters to reinforce hole cleaning. A disadvantage is that no returns of quenched glass cuttings would be observed to diagnose the appearance of magma. Late identification of the arrival at the magma target zone, which would critically increase risk of failure, could prove to be a downside of this technique. Attaching a high-temperature logging unit to the bottom-hole assembly (BHA) with a measuring-while-drilling (MWD) system could be worth analyzing. This system would register a significant increase in temperature once the magma chamber is contacted, potentially providing enough time to retrieve the tool to surface.

3.3 Formation communication and fracture growth

Friðleifsson et al. (2015) suggested that the conductive layer thermally linked to the magma chamber that connected the overlying hydrothermal system was hydraulically fractured and thermally cracked. Elders et al. (2014) elaborated on the possibility that the rock could have been naturally fractured from the beginning. It is possible, and likely, that the conductive aureole was naturally fractured from the beginning. This would be expected considering its extremely high temperature, which could have induced thermal cracking of the rock. The cooled fluid injected could most likely have induced an additional thermal stress to the formation, that accompanied with the mud pressure further hydraulically fractured the rock. This thermal stress can be approximated by *Eq. 2* (Zoback, 2007):

$$\Delta\sigma_t = \frac{\alpha x \Delta T x E}{1-\nu} \qquad \textit{Eq. 2}$$

A temperature difference of -400°C between the cooled injected fluid and the rock is estimated during injection period. There is no data on the thermal expansion coefficient, Young's modulus and Poisson ratio of the rock. Since Mortensen et al. (2014) described the injection zone as mainly comprised of basaltic dykes, dolerites and granophyres, these parameters are assumed based on reference values of basaltic rocks. Young's modulus of basalts range between 50 and 100 MPa at ambient temperature conditions, with an average of 73 GPa that is projected to decrease to 57 GPa at 450°C (Shultz, 1993). Values for basaltic Poisson's ratio range between 0.1 and 0.3, average 0.25 and are relatively insensitive to changes in temperature (Shultz, 1993). Values of 57 GPa and 0.25 are therefore adopted for Young's modulus (*E*) and the Poisson ratio (μ). The thermal expansion coefficient (α) is assumed to be 5.4 x10^{-6} °C^{-1} based on measurements done by Griffith (1936). The resulting induced thermal stress reduction is approximately 164 MPa. Tensile failure in the rock is induced when the criteria in *Eq. 4* is satisfied:

$$\sigma_{\theta_{min}} = 3S_h - S_H - PP - PM \qquad \textit{Eq. 3}$$

$$\sigma_{\theta_{min}} + \Delta\sigma_t + TS < 0 \qquad \textit{Eq. 4}$$

Considering the vertical depth of the formation and a lithostatic gradient close to 1 psi/ft, the total vertical stress would be approximately 45MPa. The minimum horizontal stress would be lower than the vertical stress in a normal fault regime or a strike-slip regime. The inner pressure of the well (PM) and the pore pressure (PP) should be fairly similar and close to the hydrothermal gradient. The maximum possible value of the hoop stress in this case would be in an isotropic state in which all principal stresses were equal. In that scenario, the hoop stress would be approximately 52MPa, which is still far below the induced thermal stress. Tensile strength (TS) could be considered to be zero since the formation is naturally fractured. Therefore, this thermal differential stress was probably large enough to induce tensile failure in the rock.

Considering that cooled water was injected for a month at a rate of 20 lt/s (~ 1700 m^3/d) before the beginning of the production stage and after the production casing was set (Mortensen et al., 2014), it is reasonable that the injected fluid created the fracture geometry necessary to communicate the upper conventional geothermal reservoir to the heat-transferring system that laid above of the magma chamber. In this scenario, depending on the natural fractures' width, the fluid could have percolated into these pre-existing fracture system and further created a complex fracture network (CFN), or it could have developed a planar fracture geometry if the fluid's viscosity was too large to infiltrate the narrow natural fractures. Additionally, no data on the principal stresses was presented in the available bibliography, although it can be inferred that since the fractures grew vertically to communicate the upper reservoir, the stress state had to be in either normal or strike-slip regime. Ziegler et al. (2016) showed that the stress state in Iceland at depths between 2 – 2.5 km is predominantly strike-slip, which is consistent with vertical fracture growth. Had the stress sate been in reverse regime, then the fracture plane would have grown horizontally and communication with upper formations would not have occurred.

An additional major challenge is ensuring flow sustainability during production. Volumetric differences between the injected fluid and the produced steam disregarded the hypothesis that production was due only to the extraction of injected fluid (Friðleifsson et al., 2015). It is believed that the produced fluid from IDDP-1 well came from shallower geothermal reservoirs contacted through a fracture network hydraulically induced in the layers above the magma chamber. The fluid was then presumed to be heated by a conductive metamorphic rock before entering the well (refer to *Fig. 8*). With such a complex process, it cannot be guaranteed that such connection between the shallower formations and the deeper heating source will always be maintained. Additional geomechanics analysis would be necessary to characterize fracture growth and identify local fracture barriers that could prevent such connection and an adequate stimulation treatment would need to be defined. Conventional EGS involving injection of cold water in a well and production of superheated fluid in a neighbor well could also be an alternative worth evaluating to become independent of the communication with upper formations. In this case, the large thermal stress induced by the injection of cool fluid would be an advantage as less wellhead pressure would be required to initiate rock fracturing.

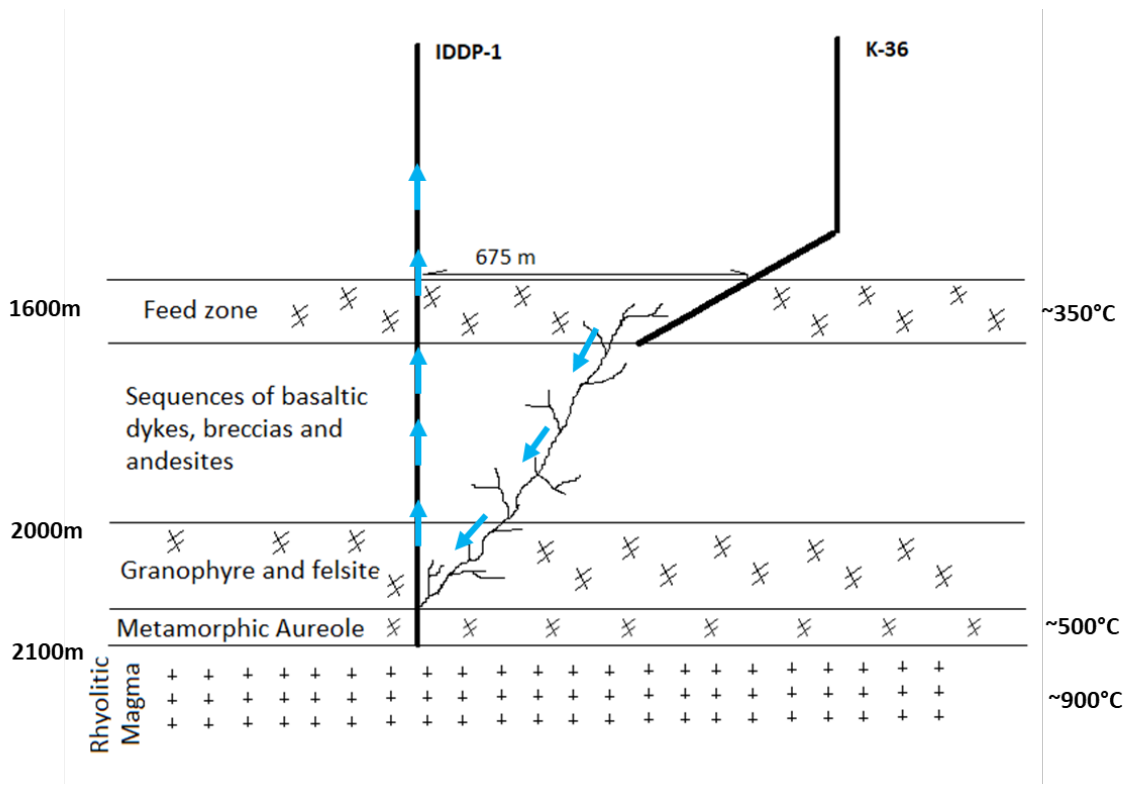

Fig. 8: Schematic diagram with the presumed fluid path that conforms the magma-EGS system in IDDP-1. Stratigraphy is detailed in Mortensen et al. (2014).

4. Conclusions

Although the first well drilled as part of the Iceland Deep Drilling Project was unsuccessful in testing supercritical fluids, it became the world's hottest producing geothermal well with a record flowing temperature of 450°C. It proved the existence of a magma chamber at 2 km in Krafla, where temperature is estimated to be around 900°C.

Huenges (2017) defined enhanced geothermal systems as “geothermal reservoirs in which technologies enable economic utilization of low permeability conductive dry rocks or low productivity convective water-bearing systems by creating fluid connectivity through hydraulic, thermal, or chemical stimulation”. Because its production is believed to be a result from hydraulic and thermal cracking of a metamorphic formation heated by a magma chamber, the IDDP-1 well is considered by this definition to be the first productive Magma-EGS in the world (Friðleifsson et al., 2015, Friðleifsson et al., 2021).

When considering the size of the huge magma chamber based on seismic measurement, it is believed that Krafla power plant could probably multiply its energy production by an order of magnitude from the currently installed capacity of 60 MWe (Friðleifsson et al., 2021). However, several engineering challenges need to be addressed beforehand related to casing integrity, managing of loss circulation during drilling and surface equipment design. Thermal strains acting on the casing and corrosive environments affecting wellhead and surface facilities appear to be the biggest challenges to overcome before venturing into a development of this kind.

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