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CASING FAILURE ANALYSIS AND PROPOSED REPAIR FOR WELL OW-740A IN OLKARIA GEOTHERMAL FIELD

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ABSTRACT

Geothermal wells experience extreme temperature changes during production and if the wells are not properly designed and the casings cemented in place properly, the wells are likely to experience failure during production (Kaldal et al., 2015). Well OW-740A is an example of such failure where casings have parted in three locations, i.e., 187, 198, and 318 m depth. The well started developing steam leakage between the 20" and the 13-3/8" casings after about one year of being shut-in after drilling and testing. A quenching operation was conducted to try and reduce the wellhead pressure and also to replace the leaking master valve followed by a caliper logging to establish the condition of the casing string. This is when the casing failure was detected at the three locations. The main cause of these multiple failures in the casing string is largely unknown but the most logical hypothesis points to faults in cementing of the production casing and thermal stresses induced in the well due to acute changes in temperatures during quenching from about 300°C to around 26°C. These stresses must have taken a huge toll on the K55 grade material of the casing leading to plastic deformation followed by snapping of the casing during cooling Currently, the well is under vertical discharge through a 10" blowpipe at a discharge pressure of 6 bar_g, and the analysis conducted in this study suggests that under these conditions the well formation has enough containment pressure to prevent a blowout. Therefore, the safety of the well and surface equipment is ensured when the well is discharging. In this study, an analysis is done on the well including drilling data, pressure-temperature relationship, casing caliper logs, and cementing of the well. This forms to basis for a comparison of the casing design to the Africa code of standards for geothermal drilling through a casing failure evaluation. Establishing the root cause of the failure helps to find the best intervention procedure and to improve the design of future geothermal wells in Olkaria. Casing failure is not unknown in the geothermal industry and this study does further look at other geothermal fields for comparison to come up with a proposal for repairing well OW-740A.

1. INTRODUCTION

Olkaria geothermal field is located in the central segment of the East Africa Rift system, as shown in Figure 1 (Mwangi and Mburu, 2005), and currently produces 865 MW_e. It is the largest geothermal field in Kenya with an estimated area of about 205 square km (Atwa; 2018). Approximately 318 wells have been drilled to date with the first production well drilled in the 1970s.

Well OW-740A, located in Olkaria Northeast (Kengen, 2017), experienced casing failure and forms the basis of our study of how exposure to extreme geothermal temperature variation can compromise the integrity of a well. Based on the initial well discharge data, well OW-740A has the potential to produce 7.9 MW_e at steady discharge conditions at a pressure of 12 bar_a and an average enthalpy of 2613 kJ/kg.

The well was drilled in 101 days using two rigs in two sections and was completed on March 27, 2018. It was designed as a production well to supply steam to the proposed Olkaria VII power plant project (KenGen, 2017). Exactly one year and four months after the completion of the well, on July 3, 2019, steam leakage was reported during a well-sitting committee forum. The steam leakage developed between the surface and the anchor casings. In addition, there was observable steam leakage also at the master valve and along a fracture at the bottom of the cellar which is trending in E-W direction as shown in Figure 2.

FIGURE 1: Location of Olkaria geothermal field (Mwangi and Mburu, 2005)

This leakage increased over time to the point that fumaroles developed at the well pad in the areas surrounding the cellar and it could soon become uncontrollable if it was left uncontained (Figure 3). It was at this point that a quenching operation was recommended to lower the wellhead pressure and investigate the cause of the steam leakage. Quenching was done on 8th of August 2019 at a rate of 25 l/s using a high-pressure triplex pump cementing unit and after 4 hours the well was successfully killed. Continuous pumping was allowed so that a logging operation could be conducted. A multifinger caliper survey suggested that the casing had parted at various locations, i.e., 187 m, 198 m, and 318 m depth.

FIGURE 2: Situation at well OW-740 at the initial stages of steam leakage development (July 2019)

FIGURE 3: Steam leakage at later stages of development

After the survey, the well was let to discharge vertically to avoid pressure build-up. Furthermore, the additional containment measure of conducting a squeeze cementing operation was done to try and seal the conduits that were transmitting steam to the surface. This was done by welding two halves of the 20” casings in place, then pumping through a valve to squeeze as much cement slurry as possible while the well was discharging. The volume of cement slurry pumped during this operation was about 4 m^3. This process is documented in Figure 4. After the squeeze cement job, leakage between the casings stopped including steam escaping between fractures.

1. Welding the containing casing in place

2. Welded casing ready for the squeeze operation

3. Conducting the cementing squeeze operation

4. After conducting the squeeze operation and pumping 4m^3 of slurry

FIGURE 4: Squeeze cementing operation at well OW-740A (KenGen, 2019a)

A permanent solution is however urgently needed to repair the failed casings to ensure long-term production from the well. The purpose of this study is to look for the most economic, realistic, and technically feasible solution to the Olkaria situation. We employed the methodology presented in section 3. The well was quenched twice. The first quenching was to enable cbl log to be carried out. The second quenching was to see if we had control of the well after cement squeeze. The timeline for the activities is shown in Table 1.

TABLE 1: Timeline of activities at OW-740A

Start date	**End date**	**Description**	**Duration (days)**	Q1, 2017			Q2, 2018			Q3, 2018			Q4, 2018			Q8 2019			Q10, 2020			Q10, 2020			Q17, 2021		
				O	N	D	J	F	M	A	M	J	J	A	S	J	A	S	J	F	M	A	M	J	O	N	D
29/09/ 2017	26/10/ 2017	1st Rig (N370)	27																								
12/01/ 2018	27/03/ 2018	2nd Rig (KGN 1)	74																								
11/07/ 2018	05/09/ 2018	Discharge test	56																								
03/07/ 2019	04/07/ 2019	1st steam leakage observed	1																								
08/08/ 2019	09/08/ 2019	Quenching	1																								
08/08/ 2019	09/08/ 2019	Calliper log	1																								
03/02/ 2020	04/02/ 2020	Squeeze cement	1																								
24/02/ 2020	25/02/ 2020	Quenching																									
04/02/ 2020	15/11/ 2021	Vertical discharge	650																								

2. LITERATURE REVIEW

In petroleum drilling, the most important factors to consider in casing design include casing weight, fluid pressure, and tensile loading. However, in geothermal casing design, high temperatures contribute to most failure modes. Given the fact that most steel grades for casing materials are designed to cater to the petroleum industry further complicates the material selection process for a geothermal environments where extremely high temperatures can be expected in the reservoir formations (Hole, 2008). During the lifetime of a geothermal well, the casings are subjected to thermal-mechanical loads which may lead to various modes of failure. These loads mainly consist of casing weight, changes in temperature and pressure and therefore, ideal casing design focuses primarily on (i) axial tension, (ii) burst, and (iii) collapse pressures (Kaldal et al., 2015). The casing must be able to withstand the expected loads during its lifetime.

The casing material used in a geothermal well that is exposed to high temperatures (250-300°C) and high enthalpy 1000-2800 kJ/kg is bound to experience a considerable decrease in the material's yield strength (Pudyastuti et al., 2020). Therefore, in geothermal well design, it is prudent to consider temperature changes that are likely to be experienced to make the appropriate choice of casing design and material. Once the casing is installed in the well and cemented, it is restricted and temperature changes create axial compressive stress within the casing string. Temperature changes in a geothermal well can vary from as high as about 310°C in shut-in conditions to as low as 26°C in quenched or killed conditions (Pudyastuti et al., 2020) and this temperature variation can have a considerable effect on the material properties which needs to be investigated to prevent casing failure.

Geothermal well cementing is done in much the same way as in oil and gas wells but the environment to which the cement is exposed is considerably different (Nelson and Guillot, 2006). The bottom hole reservoir temperature in the geothermal well can be as high as 370°C. After completion, one of the risks present in a high temperature geothermal well, is the failure of the well due to heat up. When this type of failure occurs, the well production loss and workover cost can be significant in comparison to the cost of completing the well (Southon, 2005). In addition to high temperatures, the formations encountered while drilling these wells comprise of highly fractured to poorly consolidated rock which are ideal for steam production. Consequently, lost circulation presents a serious challenge to successfully cementing geothermal wells. It is not uncommon to have total losses before the intended setting point of the production or intermediate casing string (Nelson and Guillot, 2006). All these obstacles make a quality cement job in a geothermal environment such a challenging task.

3. METHODOLOGY AND WORK PLAN

The methodology adopted for this study involves a comprehensive analysis of the casing failure with the aim of finding the best possible workover intervention. This involves analysis of the available well data, doing case studies of wells in the geothermal industry with similar casing failure and their recommended workover operations, and finally a proposal of the best well intervention that is realistic, economic, and technically viable.

Integrity assessment of the well was done through pressure, temperature and multi-finger calliper logs. These data were analysed to find where the casings have parted. However, a cement bond log was not carried out and therefore the competence of the cement between the casings could not be ascertained. Casing failure evaluation was done by looking at the drilling challenges encountered and by performing a casing depth analysis.

Learning from other wells is important to benefit from the experience of other geothermal fields where the same challenges of casing failure have been encountered and successfully overcome. The wells analysed in this study include well HE-53 in Iceland´s Hverahlíð area, relief well 5R-13D in the Philippines, and a well explosion in the Onikobe geothermal power station in Japan.

Based on the study results, a workover plan is proposed. The methodology is shown in Figure 5.

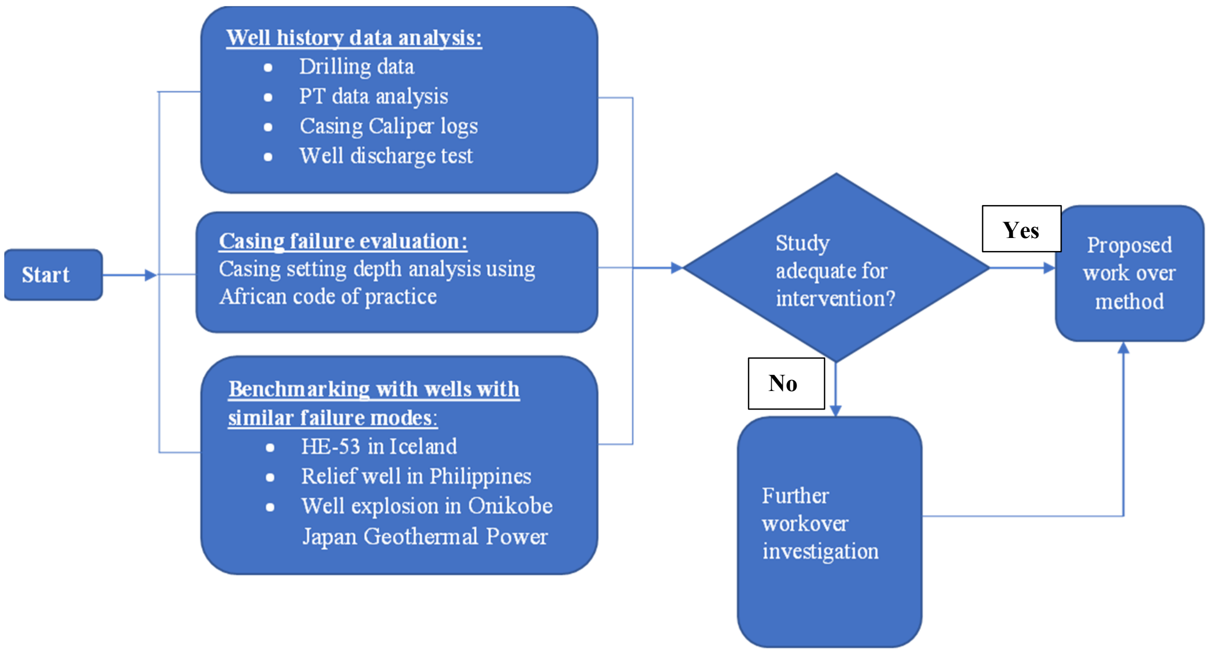

FIGURE 5: Methodology and scope of work for well OW-740A intervention

4. WELL INVESTIGATION OF OW-740A

4.1 Drilling history

Well OW 740A was designed as a production well to provide steam for the proposed Olkaria VII power plant project. The drilling of this well took a total of 101 days to a total drilled depth of 3000 m (RKB[1]) using two rigs with the first rig (Rig N370) top holing it to 307 m between 29th September 2017 and 25th October 2017. The second rig (Rig KGN1) drilled the remainder of the well to 3000 m between the 12th January 2018 and 27th March 2018.

The 26" surface hole was drilled to a depth of 62 m (RKB) and the surface casing was set at 60.45 m (RKB). A total of 5 pieces of 20" K55 grade casings were used with a weight of 94 lb/ft. They were cemented in place using 50.11 tons of cement. The 17½" intermediate hole was drilled to a depth of 307 m (RKB) with the anchor casing placed at 304 m (RKB). 30 pieces of 13 3/8" OD 54.5 lb/ft and 2 pieces of 68 lb/ft were used, all made of K55 grade of steel. They were cemented in place using 109.79 tons of cement. The 12-1/4" production section was drilled to a depth of 1007 m (RKB) with the production casing set at 991.08 m(RKB). 90 pieces of K55 9⅝" 47.0 lb/ft casings were used. A total of 59.16 tons of cement was used to hold the casings in place. The 8 ½" hole was drilled to TD of 3000 m and a total of 185 pieces of 7" K55 26 lb/ft slotted liners were run in hole and squatted at the bottom with 2 plain liners. The summary of the casing data is presented in Table 2 while the summary of drilling activities is shown in Figure 6.

TABLE 2: Casing data for well OW-740A

Nominal Size (OD)	Nominal Weight (lb/ft)	Grade	No. of Joints	Length (m)	Casing Shoe Depth (mRKB)	Rig used
20"	94	K55	5	60.1	60.45	Rig N370
13⅜"	54.5	K55	30	292.5	304	
	68	K55	2	22		
9⅝"	47	K55	90	979.18	991.08	Rig KGN1
7" Slotted liners	26	K55	185	2018.21	3000	
7" Plain liners	26	K55	2	22		

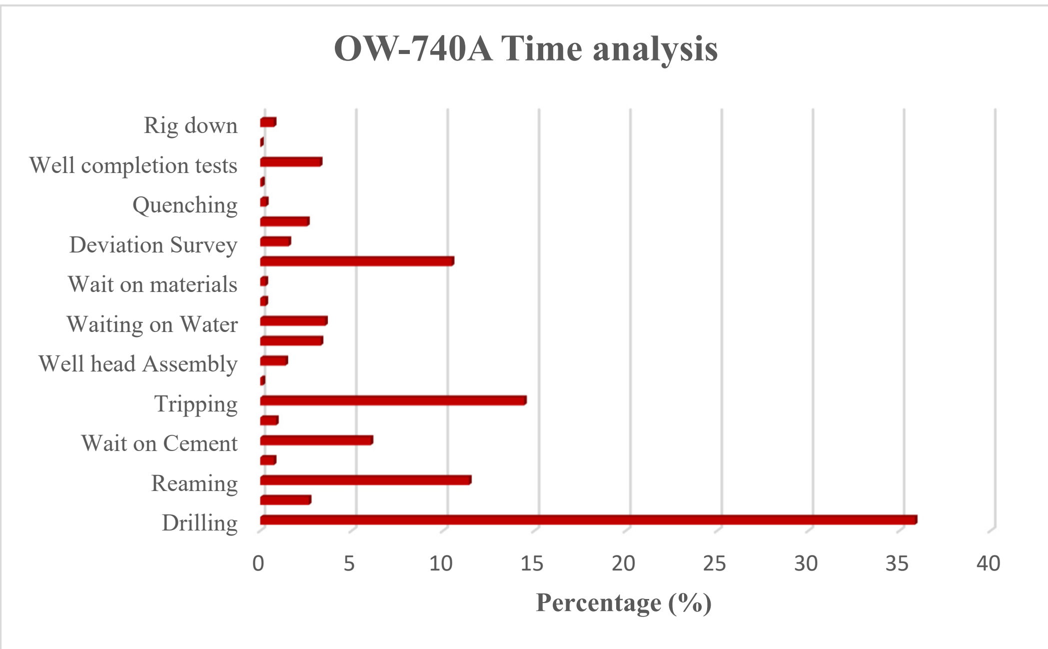

FIGURE 6: Well OW-740A drilling activities time analysis

[1] Depth of the well in this report is referred to Rotary Kelly bushing (RKB) which is 10.7 m above the ground

4.2 Challenges encountered during drilling

According to the drilling completion report (KenGen, 2018b), these were the major drilling challenges:

- Several obstructions were encountered while drilling the 12¼" hole sections. These obstructions were encountered at 381 m, 385 m, 393 m, 394 m, 436 m, 560 m, and 759 m which resulted in many days spent reaming the wellbore.
- The tight hole at 387 m (below casing shoe) was the most troublesome leading to many days of reaming and challenges while RIH of the casings.
- These obstructions became more apparent while RIH 9⅝" casings. Efforts to circulate the wellbore to ensure smooth RIH casings were not fruitful compelling the team to remove one casing. This resulted in a change of the original casing depth from 1007 m to 991 m.
- While drilling the 8½" hole section using aerated water and foam, the well kicked at various depths, i.e., at 2605 m, 2643 m, and 2930 m, resulting in quenching before drilling continued. This quenching may have damaged (possibly) the badly cemented casing.

4.3 Geological formations encountered

Stratigraphy encountered during drilling was as presented in Figure 7 (KenGen, 2018b).

0-50 m: Pyroclastics. Loose unconsolidated cuttings mainly of tuffs, trachytes, lithic material, obsidian, volcanic glass, and pumice. Washouts and cavings are likely to be experienced in this zone.
50-200 m: Rhyolite. This zone consists of relatively fresh to slightly altered and oxidized rhyolitic lavas with minor intercalations of scoria and tuff. Formation is mainly medium-hard and generally massive although fractured. Circulation losses may occur.

200-600 m: Rhyolite and tuff. This zone consists of mainly weakly altered rhyolite. Generally, the tuff formation is expected to be medium soft, and blocky lavas are expected in layers with rhyolitic formation.

600-1200 m: Trachyte and interactions of rhyolite. This zone consists of trachyte with occasional rhyolite. Minor intercalations of basalts and tuffs may be intercepting. This

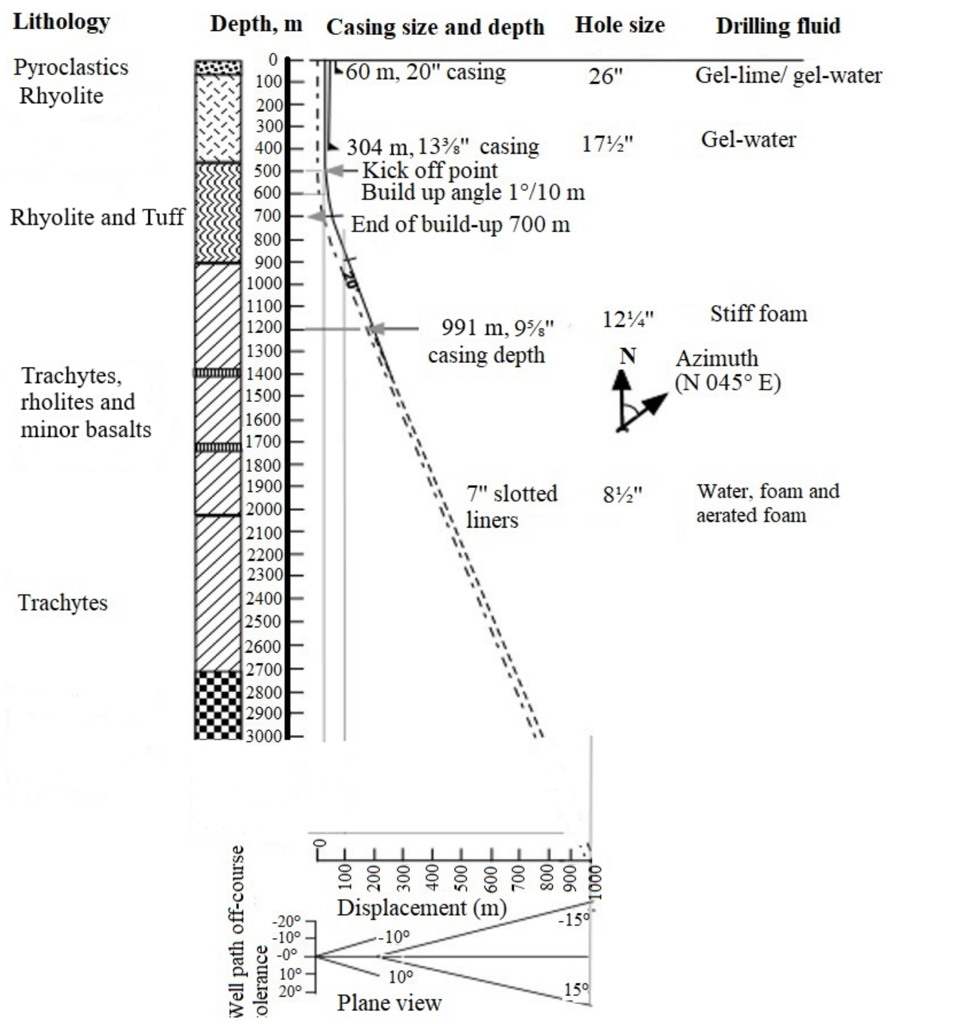

FIGURE 7: Well design for well 740A showing the lithology (KenGen, 2018b)

zone is moderately hard to hard and partial losses may be experienced. Production casing may be set in this zone.

650-3000 m: Trachytes. This zone is mainly made up of trachytes with occasional interactions of thin layers of rhyolitic lava flows. The formation is expected to be medium-hard and moderately altered. Minor losses may be experienced.

4.4 Well discharge test

Well OW-740A had a shut-in well head pressure of 106 bar (1547 psi). It was opened for discharge on 11th July 2018 at 1030 hrs and was discharged for 63 days before being shut-in on Tue 4th September 2018 at 1200 hrs. During this period, it was discharge tested using the lip pressure pipe method. The well discharged high enthalpy fluids (>2500kJ/kg) and it sustained flow on 8”, 6”, 5”, 4” and 3” lip pressure pipes while maintaining high well head pressure of above 5.0 bar (KenGen, 2018a).

This test confirmed that the well was mainly producing from a steam-dominated zone with a water to steam flow ratio of 1:7. For steady flow discharge conditions at a pressure of 12 bar_a, the well discharged 57 t/h steam, 1.5 t/h water, and 61 t/h total fluid flow with a discharge enthalpy of 2613 kJ/kg and power output of 7.9 MW_e. A summary of the discharge data is shown in Table 3.

TABLE 3: A summary of well discharge parameters at stable well head conditions

Lip pipe	WHP (bar_g)	Mass (t/h)	Enthalpy kJ/kg	Water (t/h)	Steam (t/h)	Power (MW_e)
8"	5.8	59.2	2667	0.1	57.0	7.9
6"	7.5	60.3	2654	0.6	58.0	8.0
5"	10.0	59.5	2647	0.8	56.6	7.9
4"	15.3	60.0	2578	2.6	54.7	7.6
3"	24.7	57.2	2521	3.9	51.0	7.1

4.5 Casing failure inspection

A quenching operation was conducted on 8th August 2019, followed immediately by a casing inspection survey. At first, a dummy run was done to establish clearance in the production casing. While the water was continuously being pumped, a PT survey was carried out to a depth of 350 m. Thereafter, the casing calliper tool was run while cold water was being pumped. This was performed by a MAC60 tool which is a 60 multi-finger, starting at 350 m depth moving upwards to 50 m. The survey was not run deeper because there were signs that the well would kick again. The result of the survey is shown in Figure 8.

The survey shows three locations where the casings have parted. These are at 187 m, 198 m, and 318 m depths. The full extent of these damages is presented in the expounded view in Appendix A and B.

The parted casings at 187 m and 318 m depths seem to indicate a perfectly circular increase in internal diameter that may be attributable to the parting of casing. The breach at 187 m is the widest suggestive of a typical casing failure which may be due to sudden thermal stresses caused by sudden quenching of the well. The casing breakage at 318 m is the likely origin of passageways for steam to the crevices leading to the surface. The casing breakage above is inside the anchor casing and should not cause steam leakage unless the anchor casing is broken as well.

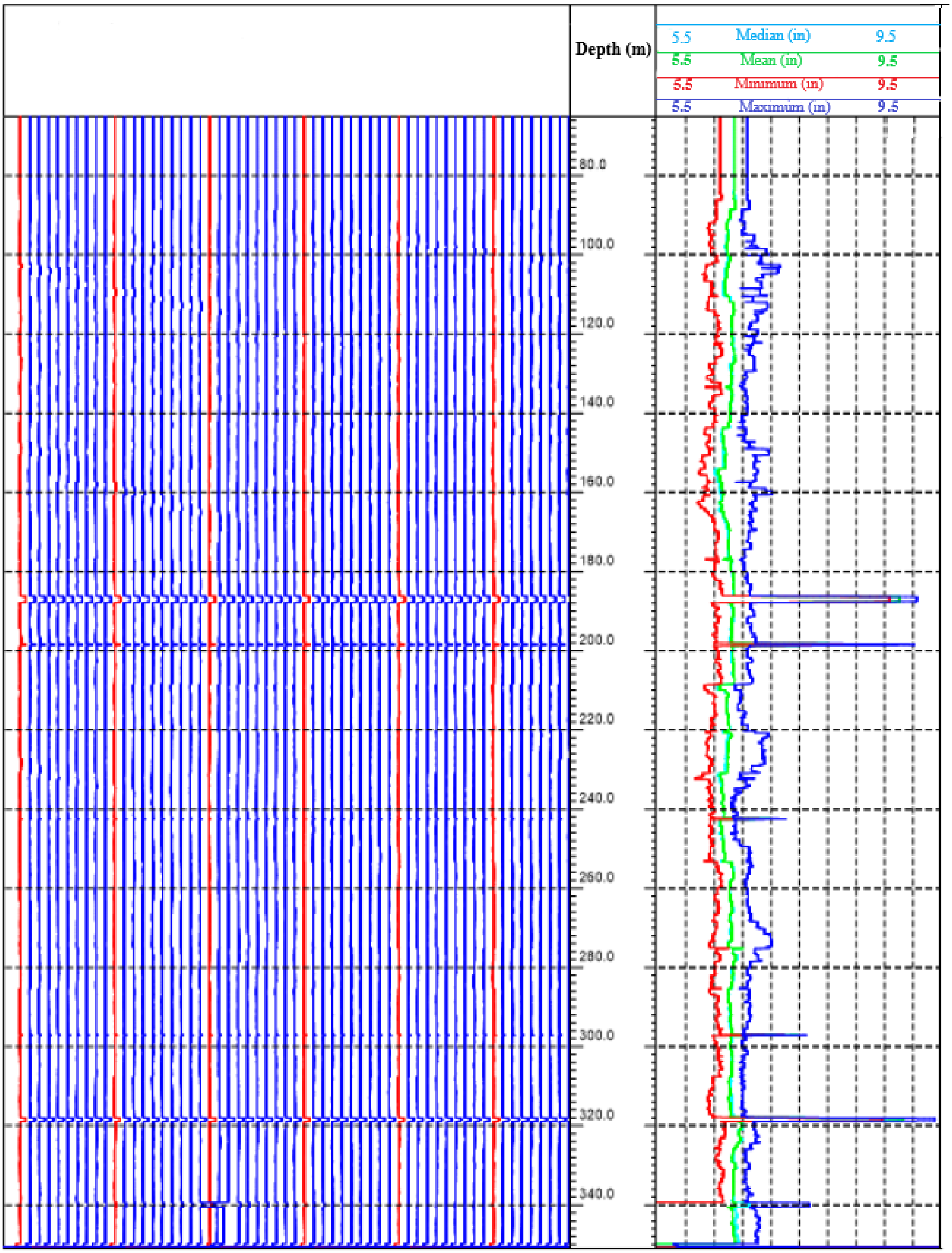

FIGURE 8: Full range calliper results (KenGen, 2019b)

Due to parted casings, flow of steam to the surface becomes possible as shown in Figure 9. With time this flow between anchor casings and the surface intensified as steam found its way to the surface.

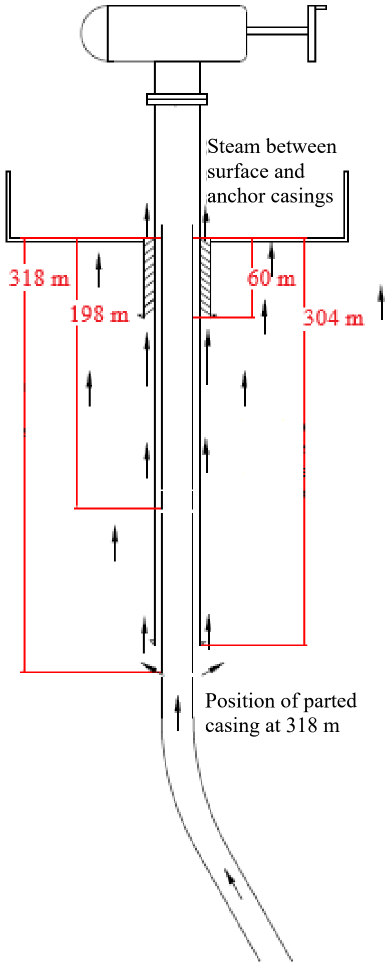

FIGURE 9: Possible flow of steam in well 740A due to the parted casings

5. CASING SET ANALYSIS

5.1 Casing set analysis design according to the African code of practice

According to the African code of practice which was adopted from New Zealand's standard of geothermal wells, the minimum casing shoe depth for each cemented casing should be calculated to the depth where the formation has sufficient containment pressure to equal the maximum design pressure expected to be encountered in the next open-hole section. This is done by plotting the containment pressure of the formation using the Eatons formula (Equation 1) together with the boiling to depth curve (BPD) which represents the maximum pressure assumed in the well and finding the point of intersection of various casing depths as shown in Figure 10.

$$P_{frac} = P_f + \frac{\nu}{1-\upsilon}(S_\upsilon - P_f) \qquad (1)$$

Where,

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

P_{frac} = fracture pressure gradient
P_f = formation pressure
S_v = overburden pressure gradient
ρ = density
g = acceleration due to gravity
h = depth
ν = poisons ratio (depends on the formation and is assumed to be 0.25 in this case)

Since the well was drilled to 3000 m RKB, which is about 2990 m measured depth from the surface, the casing sets for the various casings vary from the actual casing depths used in well OW-740A as presented in Table 4. The conclusion is that, assuming the BPD, the casings depths do not comply to the African code. This deviation is though not the cause of the failure in the well.

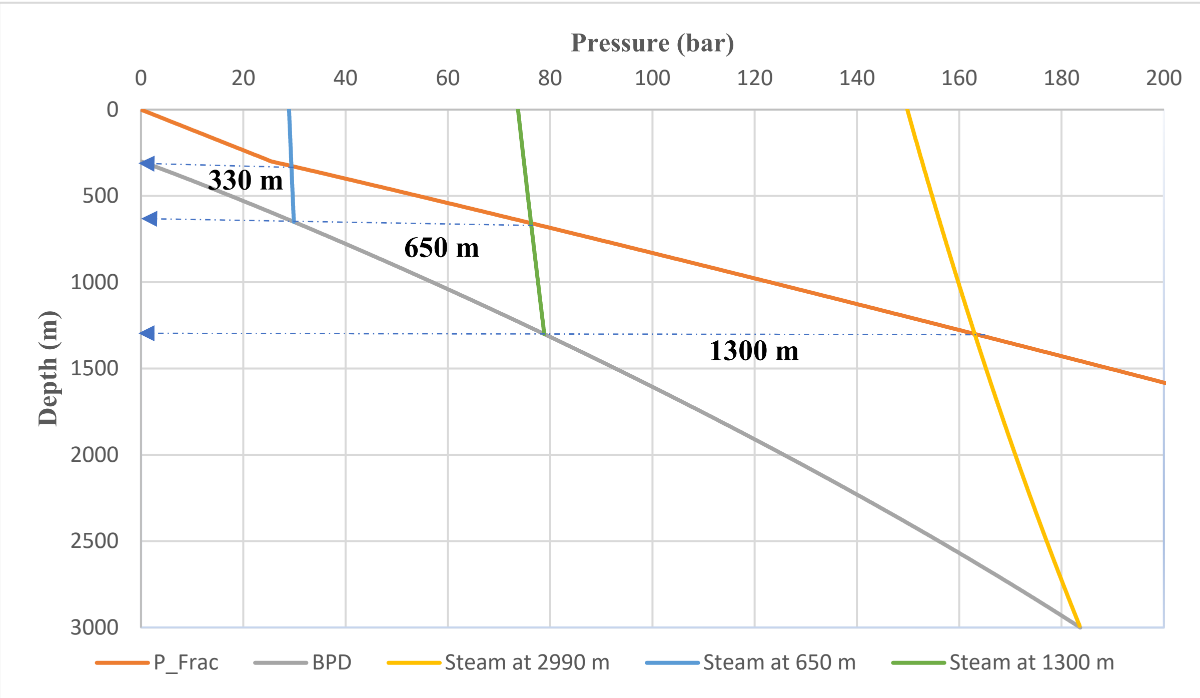

FIGURE 10: Redesigned casing set depth using the African code of practice
(the dotted line shows the intersection of pressure and formation pressure curves)

TABLE 4**:** A comparison of the designed depths with the actual setting depths chosen for the well

Casing	**Well 740A casings depths (KenGen, 2018b)**	**Redesigned OW-740A setting depths using African code of practice**
Conductor casing	-	-
Surface casing	60 m	330m
Anchor casing	307 m	650 m
Production casing	991 m	1300 m

5.2 Design of setting depth using the actual WHP

Further analysis was made based on the fact that the actual shut-in wellhead pressure is known. In the well OW-740A discharge report, it was established that the shut-in wellhead pressure was 106 bar_g. With this knowledge, the steam pressure from the wellhead was plotted down to the formation containment curve as shown in Figure 11.

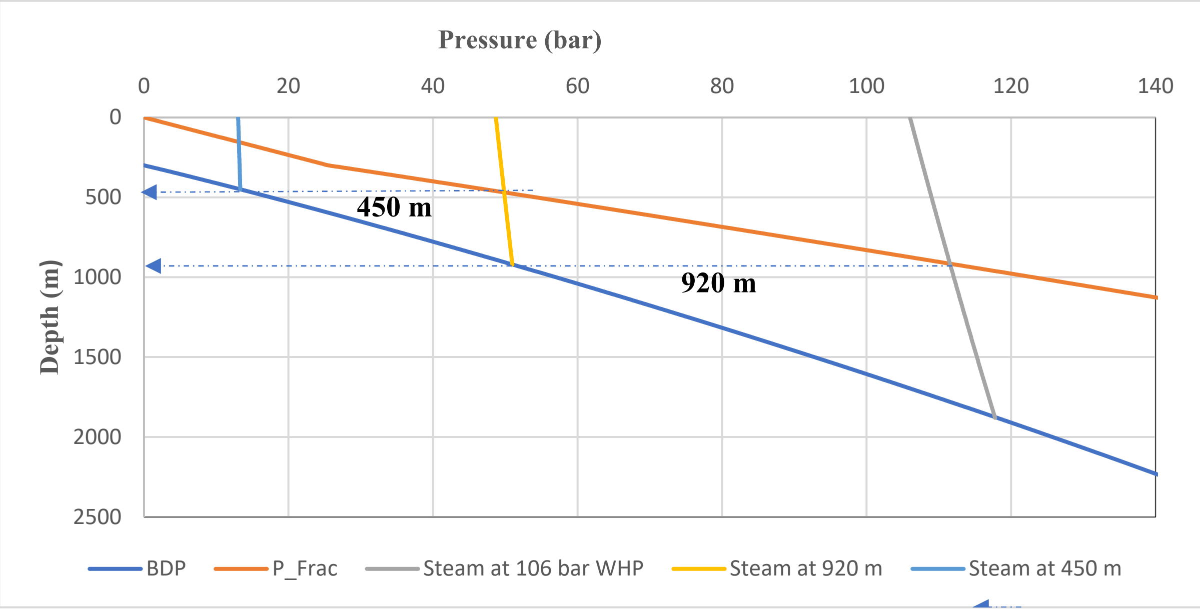

FIGURE 11: Design of the casing depth from the known WHP of 106 bar_g
(the dotted line shows the intersection of pressure and formation pressure curves)

From this plot, we see that the minimum casing depths for the production, anchor, and surface casings are 920 m, 450m, and 100m. The comparison with actual setting depths is shown in Table 5.

TABLE 5: A comparison using actual WHP with the actual setting depths

Casing	**Well 740A casings depths (KenGen, 2018b)**	**Redesigned OW-740A setting depths using the actual WHP of 106 bar_g**
Conductor casing	-	-
Surface casing	60 m	150 m
Anchor casing	307 m	450 m
Production casing	991 m	900 m

From this analysis, we can deduce that the production casing was set at the appropriate design depth. However, the plot also shows that the pressure in the well at 318 m depth, where the casings have failed, is way above the containment pressure of the formation.

5.3 Pressure at 318 m at the current discharge condition

At the time of writing this report, the well was discharging vertically through a 10” blowpipe. Therefore, it is important to ascertain whether the well is safe if left to discharge at the current discharge pressure of 6 bar_g. This was done by looking at the depth where the well can contain this pressure by plotting the steam curve from the surface down to the formation pressure curve as shown in Figure 12.

From the plot, we see that the minimum depth that the formation can contain this pressure is about 70 m. Therefore, at the point where the casing has parted (318 m) the rock has enough containment strength to sustain the discharge from the surface. It is however not strong enough if the well is shut in.

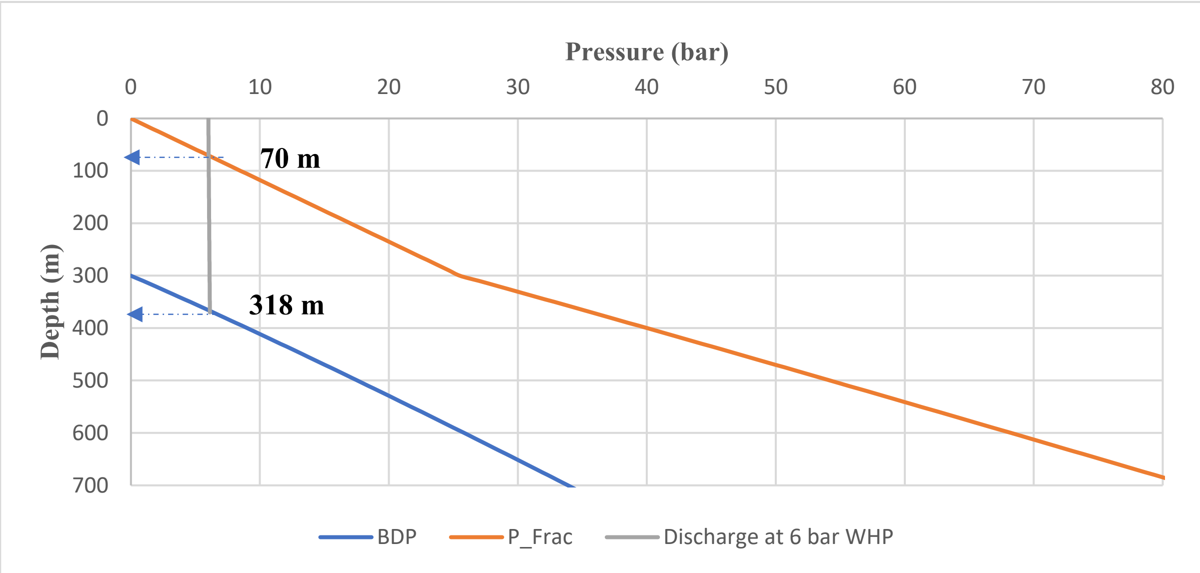

FIGURE 12: Pressure at the parted casing relative to the containment pressure of the formation (the dotted line shows the intersection of pressure and formation pressure curves)

6. BENCHMARKING AGAINST OTHER WELLS IN THE GEOTHERMAL FIELD

In this section, we will compare three wells in different geothermal fields that have experienced similar cases of casing failure and analyse how they solved their challenges. These fields are:

i. Well HE-53 in Hellisheiði geothermal field in Iceland

ii. Relief well in Philippines

iii. A Large Wellfield Steam Explosion at the Onikobe Geothermal Power Station in Japan

6.1 Well HE-53 in Hellisheiði geothermal field in Iceland

Well HE-53, a production well drilled in Hellisheiði geothermal field in Iceland, experienced casing failure at around 308 m depth. Having been drilled between 9 April to 16 June 2009, the well was directional inclining at a 30° angle with a kick-off point at 443 m and drilled to a measured depth of 2507 m (Mannvit, 2010a). After the well was shut in following a discharge test, the wellhead pressure remained high at 104 bar. Because the well was not to be used for a while, it was decided to quench it to lower the WHP. This quenching done from November 3 for 15 days may have played a role by inducing thermal stresses to the casings causing the casing to fail by parting at a depth of 308 m where the cementing of the casing was poor. The broken casing at 308 m was further confirmed by conducting a temperature measurement that showed a sudden rise in temperature at 308 m and comparing it with the presence of steam in the nearby well HE-36 which had unusually high temperatures between 250 - 340 m in the strata. This parted casing posed an inherent risk as it could cause a blowout that could turn out to be catastrophic endangering subsurface structures. The method chosen to solve this challenge was to pump a cement plug inside the wellbore with a predetermined slurry density and column long enough to overpower the steam pressures from the well (Mannvit, 2010b). A cement plug was pumped and the operation was largely successful as the cement plug was eventually drilled out and a smaller casing was installed through a tie-back cementing procedure (Mannvit, 2011).

6.1.1. Cementing plan

Pumping a cement plug was concluded to be the safest option. Since the pressure at 308 m which was the point of casing breakage was 70 bar_g, a 400 m plug with a density of 1.75 kg/l would be sufficient to compensate for this pressure. This means that about 15.3 m^3 of slurry was enough to kill the well. The pumping rate chosen was around 1200 l/min. Mica was also to be included in the cement blend at a rate of one bag per 1 m^3 of slurry. Possible risks were cement flowing past the zone and cementing most of the feed zones.

6.1.2 Cementing

The well was cemented according to the plan above and the pressure dropped steadily as the cement slurry pumping continued. A total of 40 m^3 of slurry was pumped which was more than the planned volume.

6.1.3 Tieback cementing

The well was allowed to set and after a few days, the top of cement was found to be at 134 m. A method was chosen to repair this well which involved drilling the well to the liner hanger and stopping at about 2-3 singles from it. Cleaning was done and subsequent inspection of the 9 -5/8" casing was done to ascertain the extent of the damage of the casings (Figure 13). Afterwards, a 7" casing was run and cemented in place.

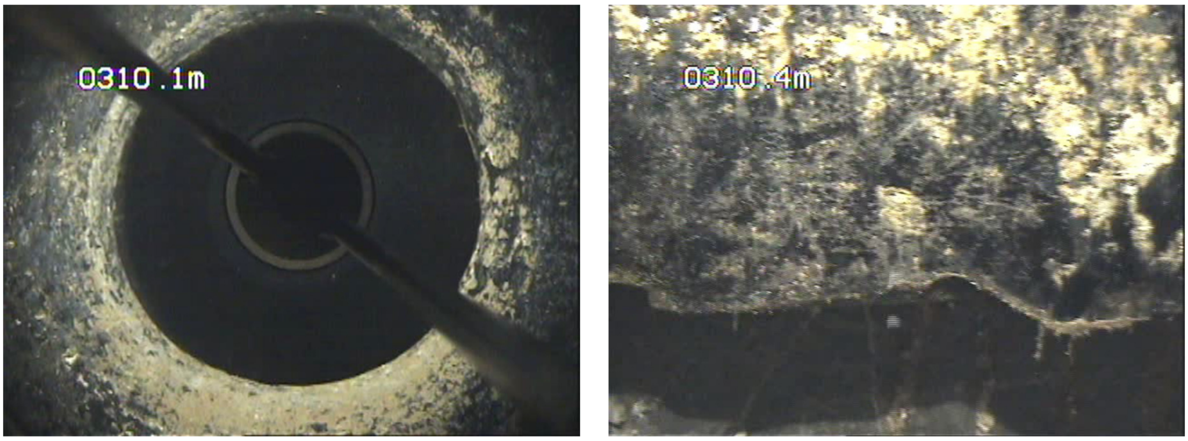

FIGURE 13: Pictures showing damaged casing at 310 m
(photo courtesy of HE-53 casing report by Mannvit, May 2011)

6.1.4 Steam loss

The steam production from the well decreased by 15% after repairing the well with a 7" casing lining.

6.2 Relief well at Malitbog in the Philippines

A relief well was drilled to intercept a well that had experienced an extreme blowout at Malitbog in the Philippines. This was the first relief well to be drilled in the Philippines by Philippine National Oil Company Energy Development Corporation (PNOC-EDC) in October 2003 (Jumawan et al, 2005).

Moreover, this was the first relief well to be directionally drilled using the single-shot directional survey technology. Well 5R-13D was designed and drilled to relieve pressure of the uncompleted well 5R-12D that blew out and even toppled the mast of the drilling rig after encountering a shallow pressurized zone at 450 m with a pressure of 40 bar (Figure 14).

FIGURE 14: View of well 5R-12D that blew out and toppled the rig (Jumawan et al, 2005)

Despite drilling challenges like the non-utilization of the MWD tools and the proximity of the well pad to a main geologic fault prompting a revised well direction, well 5R-13D successfully intersected and quenched 5R-12D. A series of cement plug jobs were conducted at well 5R-12D. Completion tests at well 5R-13D showed that this well can be utilized as a production well. Therefore, the relief well drilling was successful.

6.3 A large wellfield steam explosion at the Onikobe geothermal power station in Japan

This is an extreme case where steam exploded in a producing well. Well 128 exploded near the 15 MW_e Onkobe power plant on 17^{th} October 2010 (Akasaka et al., 2011). It all started with the development of new fumaroles accompanied by a hot liquid in September 2010. Attempts were made to reduce the wellhead pressure by pumping cold water but fumaroles continued to grow culminating in a large-scale steam explosion on 17^{th} October 2010. A large crater was formed and the well got submerged in hot water. Unfortunately, one life was lost in this incident, and another worker was severely burned.

FIGURE 15**:** Development of fumaroles near well 128 in September 2010 (photo from Akasaka et al., 2011)

6.3.1 Sequence of events

In September 2010, near well 128 two small geothermal manifestations started to form as shown in Figure 15. No alarm was raised at this point since fumaroles are a common occurrence in most geothermal fields (Gresse et al., 2018) including this one at Onkobe. The thermal activity started increasing a month after it was first detected, i.e., on 8 October 2010.

The well was shut in together with two more adjacent wells (well 136 and well 138) to allow injection of cold water and reduce the wellhead pressure. On October 15, 2010, cold water was pumped into well 128 through a six-inch bleed valve downstream of the open wellhead valve but failed to reduce the wellhead pressure. This prompted the increase of the injection rate by pumping also through the bleed valve.

FIGURE 16: Steam explosion captured 5 km west of the field (photo from Akasaka et al, 2011)

6.3.2 Steam explosion

A destructive steam explosion occurred ejecting soil and rocks accompanied by rumbling of the ground on 17^{th}

October 2010 (Akasaka et al, 2011). The erupting material consisted of rocks, soil, and gravel which were mainly subsurface materials (Figure 16). The materials erupted up to about 250 m high creating a crater of about 45 m diameter. Discontinuous emissions of steam and muddy water continued after the eruption for several days but the discharge reduced in strength and finally ceased on 23 October, six days after the explosion.

6.3.3. Probable causes of the explosion

A hypothesis was formulated speculating on the sub-surface sequence of events:

i. A high-pressure chamber was formed at shallow depth supplied by hot fluid from greater depths.

ii. Steam started to leak from the chamber to the surface on 8th September 2010.

iii. On 16th October 2010, an in-situ boiling occurred due to the pressure drawdown resulting in a blowout.

iv. On 17th October 2010, an explosion occurred due to the accumulation of very high pressure brought about by instantaneous flashing of substantial amounts of water and steam.

Two scenarios for the formation of the pressure chamber have been hypothesized:

1. Natural fumaroles that are common in the area might have been responsible for the creation of the shallow chamber which grew in magnitude with time leading to the eventual build-up of pressure and the catastrophic rupture.

2. As this eruption occurred near a production well, maybe the well played a part in the creation of the pressure chamber. There is a possibility that the casing might have been damaged leading to gradual leakage of steam from the well to the chamber. Over a long period, the pressure in the chamber grew in magnitude leading to the eventual eruption.

The three cases are compared in Table 6.

7. DISCUSSION

7.1 Overview

The data analysis for well OW-740A revealed that the well has parted casings at 187 m, 197 m, and 318 m depth. It is safe to assume that the casing failed due to induced thermal stresses on the steel casings due to sudden cooling through a quenching operation. Further analysis of the drilling data shows that the well experienced tight hole and obstructions during drilling at between 350 m and 560 m depth. This obstruction was troublesome to the point that running the production casings was a challenge that necessitated the removal of one casing joint during the casing installation. This may have contributed to the casing string not being properly cemented around the obstruction which may have caused the eventual break of the casing around the 318 m point.

An analysis of the design of casing depths was carried out according to the African code of practice to investigate if the casing depths were correctly chosen and to further investigate the possible risks involved in the parted casing if an intervention was conducted.

With this in mind, the next step was to look at other wells in other geothermal fields that have experienced similar failures and to analyse the chosen methods of repair. From the three cases studied, well HE-53 in Hellisheiði geothermal field presented us with the best case study as the well failed in a similar pattern as well OW-740A. It had casings failure at almost the same position, i.e., 310 m, compared to 318 m for well OW-740A, and the failure was due to thermal stresses through quenching of the well. The cases are tabulated in Table 6.

TABLE 6**:** Analysis of the case studies

	Case 1	**Case 2**	**Case 3**
Geothermal area	Well HE-53 in Hellisheiði geothermal field in Iceland	Relief well at Malitbog in the Philippines	A Large Wellfield Steam Explosion at the Onikobe Geothermal Power Station in Japan
Problem statement	Parted casings at around 310 m were suspected to be due to sudden cooling.	Blowout at well 5R-12D that resulted in toppling down of a drilling rig. Continuous discharge from well 5R-12D was causing considerable damage to the environment, contamination of the nearby Malitbog River, and loss of revenue from the Malitbog power plant.	This represents an extreme case where steam exploded in a producing well. Well 128 exploded near the 15 MW_e Onkobe power plant in Japan on 17th October 2010 (Akasaka et al., 2011).
Well repair implemented	Pumping heavyweight cement with enough hydrostatic head to overcome the wellhead pressure. Performing a tie-back cementing operation by installing a smaller diameter casing inside the production casing.	Drilling a relief well 5R-13D to intercept the discharging well 5R-12D using single-shot direction survey technology.	N/A
Successful/ unsuccessful	Successful despite a 15% reduction in steam production	Successful because the relief well intersected the discharging well and it even became a producing well	N/A

The mode of repair chosen for well HE-53 included pumping a cement plug into the well with enough head pressue to overcome the pressure from the discharging reservoir. 40 m^3 of cement slurry was pumped resulting in the top of cement at 134 m depth. Later, the well was drilled and a tie-back cementing operation was conducted by running in a smaller diameter casing of 7” and pumping cement to anchor it in place. The operation proved to be successful as the well produced, albeit with a 15% reduction of steam.

7.2 Proposed intervention

Currently, the well is under vertical discharge. We have seen from Figure 12 that it is safe to let the well discharge as this does not pose any danger to the surface equipment as the pressure exerted at the parted casings is well below the containment pressure of the formation. Based on the conducted case studies, we have ruled out the method of repair by drilling a relief well as employed at Malitbog in the Philippines because it will be very complicated to drill a relief well since the well is deep, and the chances of hitting the feed zones are very limited given that we don't have MWD survey tools for directional drilling. Furthermore, well OW-740A has casings installed to TD and it will not be feasible to intersect the original well as was done in the Philippines. Case 3 is an extreme example of what happens when there is no intervention. The well experienced a catastrophic explosion causing the loss of one life.

Our aim is to choose a method that is realistic and will enable us to save the well for future production of steam. From the discharge tests, we saw that the well has the potential to produce up to 8 MW_e at a steady pressure of 5 bar. Therefore, the best intervention must not compromise the production of steam to ensure a return on investment.

The intervention in case study 1 where they were able to successfully intervene and ensure production from the well, albeit a 15% reduction in steam, might be applicable to well OW-740A. This is far better than losing the well completely. It is important also to note that the casings failed at almost the same point, i.e., at 310 m in well HE-53 and 318 m in well OW-740A.

Therefore, the proposed intervention for OW-740A is an imitation of this intervention with modifications to reduce the cement slurry affecting the feed zones of the well which would lead to reduced steam production.

The first step will be to kill the well while setting the packer to seal off the production zone and slurry pumped to form a plug that will prevent the well from kicking. This will prevent the well from further discharging. Secondly, it is important to know the minimum casing depth for the tie-back cementing. Here, we will follow the shut-in condition of the well and the graph in Figure 17 showing the minimum depth to where the casing should be set (African Union Standard, 2016).

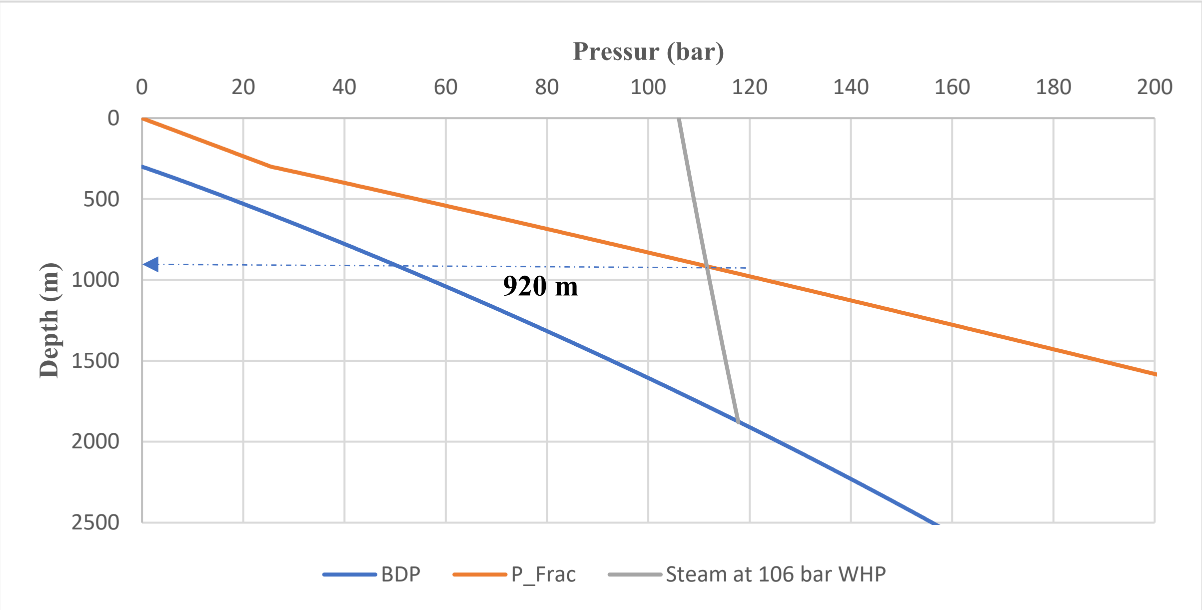

FIGURE 17: Minimum depth that the tieback casing should be set
(the dotted line shows the intersection of pressure and formation pressure curves)

A collaborative effort is needed for the teams involved to make the operation successful. Before the operation, a joint meeting for all parties is required to properly understand the risks involved, objectives to be achieved, and how to conduct the operation.

7.3 Killing the well

- By using coiled tubing equipment, a hydraulic packer will be installed while pumping water at high pressure in the live well up to the top of the liner which is in about 970 m depth. Coiled tubing is chosen in this case because previous attempts to quench the well using the cementing pumping units were unsuccessful due to the presence of conduits at the parted casings. Coiled tubing will provide a means of exerting pressure deep down the well while at the same time running the packer that will seal off the well just above the liner hanger at 970 m. The coiled tubing has been successfully used in a few operations in Menengai field in Kenya. The packer will be specially designed for high temperatures.

- After this, a cement plug with a sufficient hydrostatic head will be pumped into the production casing. The slurry should be designed in the laboratory with the following properties in mind:

    a. High density to provide enough hydrostatic head to kill the well
    b. Fast curing cement to harden and seal the well
    c. Enough LCM to avoid losses in the formation
    d. High compressive strength to ensure that the plug is strong enough to hold off the steam pressure.

- Sufficient cement should be mobilized to the site. There should be enough reserve of cement on the site to take care of any eventualities. We might be required to pump more volume than anticipated by the plug cementing program.

7.4 Tieback cementing

After pumping the well with cement, when the cement slurry attains the highest compressive strength after curing, a drilling rig will be mobilized to the well where the cement will be drilled out to a depth just below 920 m to allow the tieback casings of 7” OD to be run and cemented in place. The minimum depth for the casing should be 920 m according to the pressure containment curve designed based on the design procedure in the Africa code of practice as shown in Figure 17. Most importantly, the following should be considered:

- The casings should be run with centralizers to ensure proper centralization.
- Slurry design and volumes should be agreed upon before the operation.
- Cementing should be executed until cement slurry is received at the surface.

8. CONCLUSIONS

During well construction, it is important to follow the steps outlined in section 2.3 of the Africa union code of practice for geothermal drilling. This details a step-by-step process of well design and ensures that the well is properly designed to handle the pressures in the well and the casings shoes are placed at a safe depth. In addition, a proper engineering decision on the casing material’s grade, strength, desired size, weight, and connections of casing strings should be made during this process to ensure the lifelong durability of the well.

The next critical step is to ensure that the well is properly cemented. According to the work done by Won et al. (2016) on numerical investigations of the effect of cementing properties on the thermal and mechanical stability of geothermal wells, long-term strength degradation of the cementing might cause severe structural instability of an entire geothermal well. Therefore, proper design and cementing should be executed to ensure the well is in production for many years.

In addition, wells experiences heat up during production or discharge. When a well is suddenly brought to a low temperature due to quenching or shutting down of the master valve or the casing in the well is exposed to thermal mechanical loads, this can lead to casing failures especially when the stress reaches the yield point and beyond. This is what happened in well OW-740A where sudden quenching led to the production casing failing at three locations, i.e., 187 m, 198 m, and 318 m depth.

Despite this failure, well intervention is possible. Through investigation of similar failures in other fields, we discovered that this problem is not unique to Olkaria. Of great interest is well HE-53 in Hellisheiði geothermal field which had casings fail in a similar manner as in well OW-740A due to quenching of the high temperature well. The proposed solution to repair well OW-740A has been adapted from well HE-53 with a slight modification to ensure that we don't pump cement in the production zone which would compromise the production capability of the well.

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NOMENCLATURE

bar_g = Bar gauge;
ft = Feet;
HE = Hellisheiði;
kg/l = kilogram per litre;
kJ/kg = Kilo Joules per Kilogram;
l/s = Litres per second;
lb/ft = Pounds per feet;
LCM = Lost circulation material;
m = meter
MD = Measured depth;
MW_e = Mega watt electric;
OD = Outer diameter;
OW = Olkaria well;
psi = Pounds-force per square inch;
PT = Pressure – Temperature
RIH = Running in Hole
RKB = Rotary Kelly bushing;
t/h = tonnes per hour;
WHP = Well head Pressure
MWD = Measurement while drilling
TD = Total depth

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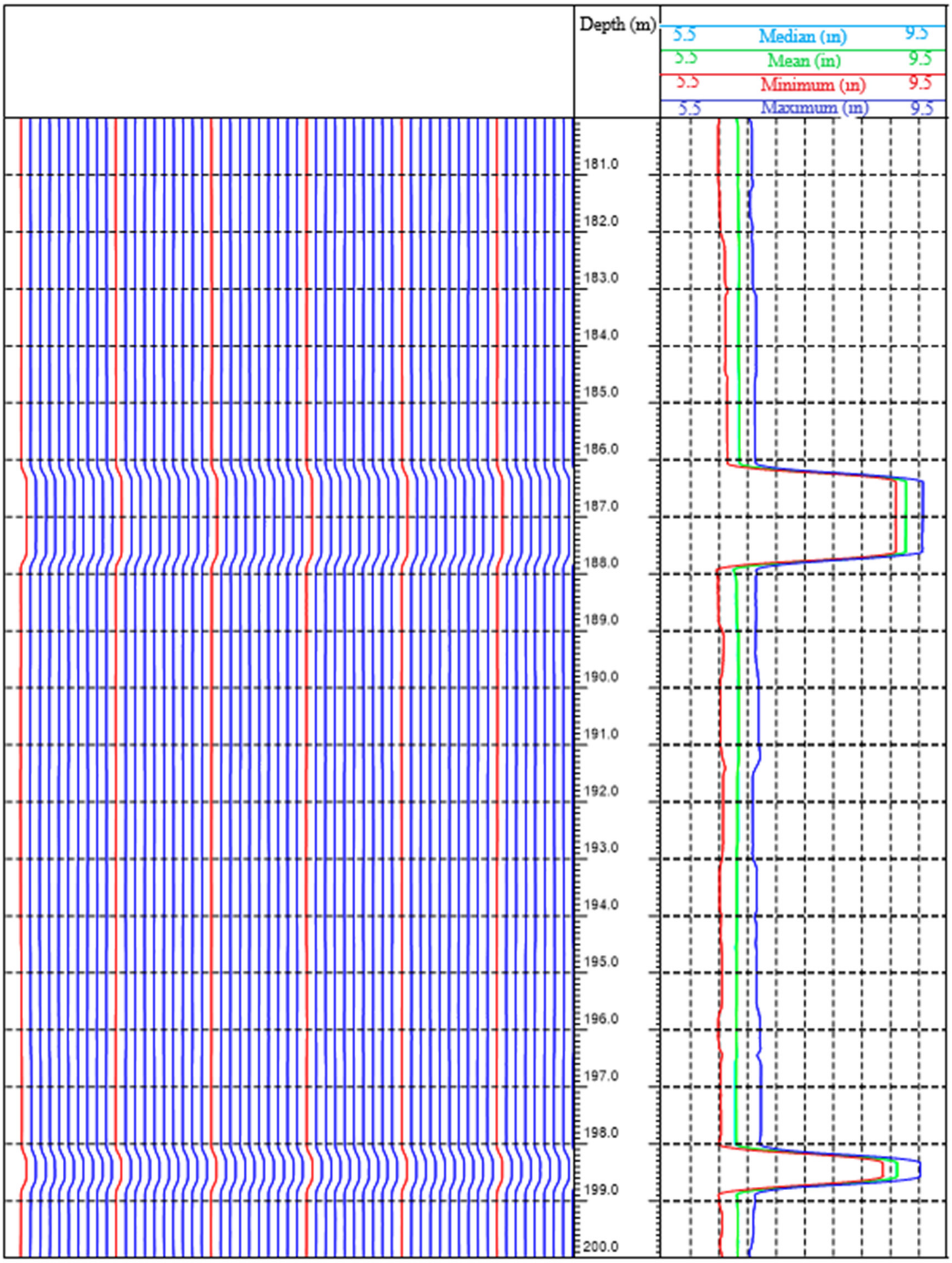
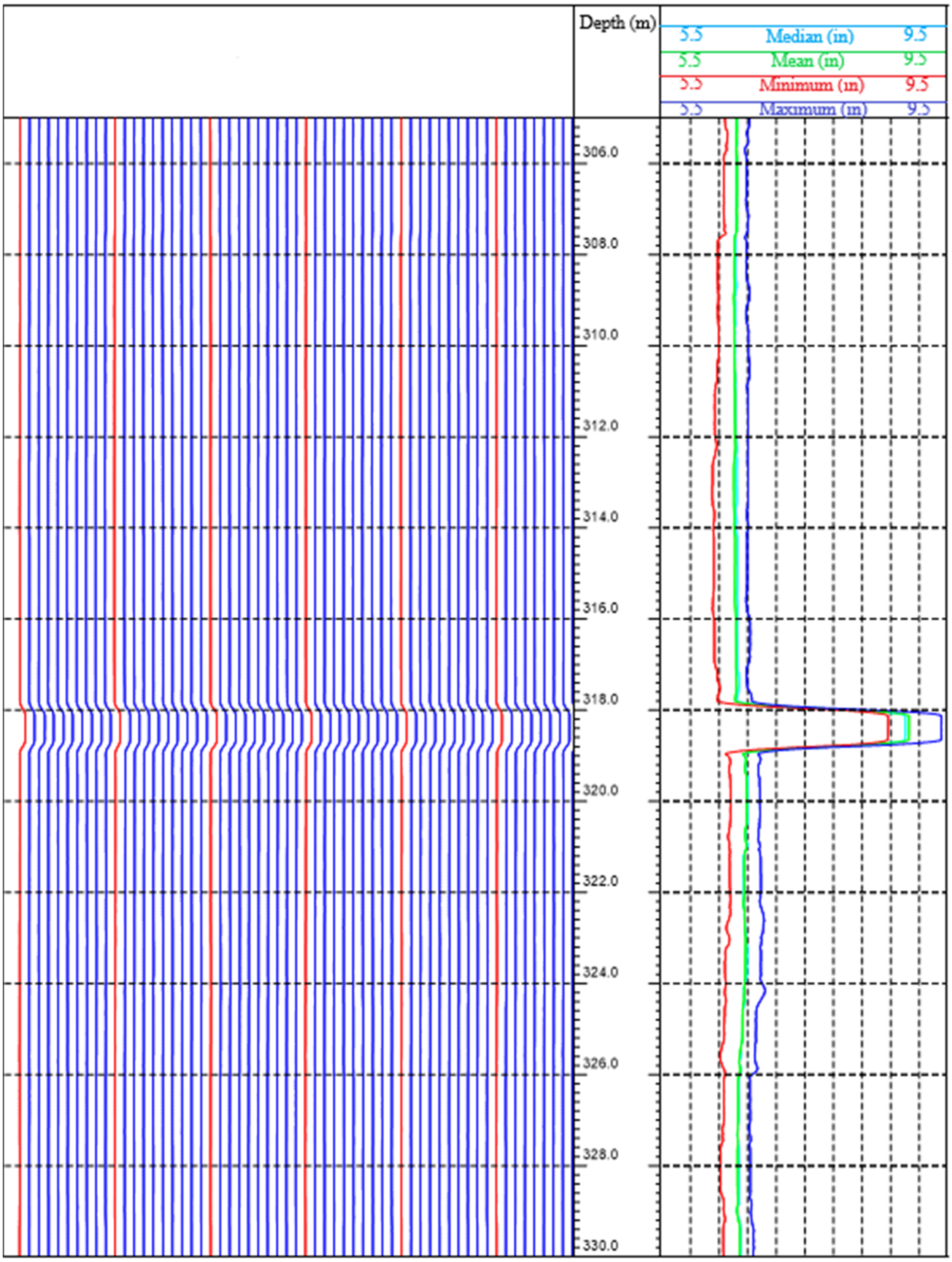
APPENDIX A

Localized calliper logs at 180-200 m depth showing casing parting at 187 m and 198 m at well OW-740A



APPENDIX B

Localized calliper logs at 305-330 m depth showing casing parting at 318 m at well OW-740A



APPENDIX C

OW-740A well discharge parameters

Shut-in WHP = 1547 Psig						
Master valve to Cellar top height = 1835mm						
DATE	**WHP (Bars)**	**Mass (t/h)**	**Enthalpy kJ/Kg**	**Water (t/h)**	**Steam (t/h)**	**Power (MW_e)**
Discharging on 8" *2 lip pipe						
11-07-18	5.5	85.9	2675.0	0.0	82.7	11.4
12-07-18	4.9	78.7	2667.0	0.3	75.6	10.5
13-07-18	4.7	78.9	2655.0	0.7	75.4	10.5
5.0	81.2	2665.7	0.3	77.9	10.8	
Blanked on one side of the fork (Discharging on 8" *1 lip pipe)						
13-07-18	6.4	74.0	2675.0	0.0	71.3	10.0
14-07-18	6.3	65.8	2674.0	0.0	63.4	8.8
15-07-18	6.0	63.0	2673.0	0.0	61.0	8.4
16-07-18	6.0	66.5	2670.0	0.1	64.0	8.9
17-07-18	5.8	60.1	2670.0	0.1	58.0	8.0
18-07-18	5.8	56.8	2667.0	0.2	54.5	7.6
19-07-18	5.8	59.2	2667.0	0.1	57.0	7.9
20-07-18	5.8	61.6	2665.0	0.3	59.2	8.2
Discharging on 6" *1 lip pipe						
21-07-18	7.7	60.5	2657.0	0.5	57.8	8.0
22-07-18	7.6	60.5	2657.0	0.5	57.8	8.0
23-07-18	7.7	57.0	2658.0	0.4	54.5	7.6
24-07-18	7.6	56.2	2656.0	0.5	52.7	7.5
25-07-18	7.6	59.4	2655.0	0.5	56.8	7.9
26-07-18	7.6	61.3	2655.0	0.5	58.6	8.1
27-07-18	7.5	60.2	2653.0	0.6	57.4	8.0
28-07-18	7.5	60.0	2657.0	0.5	57.0	8.0
29-07-18	7.5	60.3	2654.0	0.6	58.0	8.0
30-07-18	7.5	60.1	2647.0	0.8	57.0	8.0
31-07-18	7.4	60.0	2647.0	0.8	56.6	7.9
01-08-18	7.4	58.0	2643.0	0.8	55.1	7.7
	7.6	59.5	2653.3	0.6	56.6	7.9
Discharging on 5" *1 lip pipe						
02-08-18	10.0	60.3	2652.0	0.6	57.5	8.0
03-08-18	10.1	60.3	2647.0	0.7	57.3	8.0
04-08-18	10.1	59.9	2647.0	0.7	57.1	8.0
05-08-18	10.1	60.4	2647.0	0.7	57.4	8.0
06-08-18	10.0	59.5	2647.0	0.8	56.6	7.9
07-08-18	10.0	59.0	2641.0	0.9	56.0	7.7
08-08-18	10.0	59.3	2633.0	1.1	56.0	7.8
	10.0	59.8	2644.9	0.8	56.8	7.9
Discharging on 4" *1 lip pipe						
09-08-18	15.0	58.5	2600.0	1.9	54.4	7.6
10-08-18	15.2	59.0	2600.0	1.9	54.8	7.6
11-08-18	15.2	59.1	2587.0	2.3	54.5	7.6
12-08-18	15.1	60.0	2597.0	2.1	55.6	7.7
13-08-18	15.2	57.8	2646.0	0.8	55.0	7.6
14-08-18	15.3	60.0	2578.0	2.6	54.7	7.6
15-08-18	15.3	59.4	2583.0	2.4	54.7	7.6
16-08-18	15.3	60.0	2573.0	2.7	54.6	7.6
17-08-18	15.2	59.2	2595.5	2.1	54.8	7.6

Discharging on 3" *1 lip pipe						
17-08-18	24.8	55.1	2600.0	1.8	51.2	7.1
18-08-18	25.1	56.4	2568.0	2.7	51.5	7.2
19-08-18	25.1	57.5	2570.0	2.7	52.6	7.3
20-08-18	24.7	56.7	2540.0	3.4	51.1	7.1
21-08-18	24.6	58.3	2561.0	3.0	53.1	7.4
22-08-18	24.7	55.1	2600.0	2.2	51.1	7.1
23-08-18	24.7	56.5	2520.0	3.9	50.5	7.0
24-08-18	24.7	56.8	2520.0	3.9	50.6	7.0
25-08-18	24.8	57.3	2515.0	4.1	50.9	7.1
26-08-18	24.7	57.2	2521.0	3.9	51.0	7.1
27-08-18	24.7	57.6	2523.0	3.9	51.4	7.1
28-08-18	24.7	57.2	2541.0	3.4	51.5	7.2
	24.8	56.8	2548.3	3.2	51.4	7.1
Discharging on 8" *1 lip pipe						
29-08-18	5.8	59.0	2572.0	2.7	54.1	7.5
30-08-18	5.7	58.8	2562.0	3.0	53.6	7.4
31-08-18	5.7	59.7	2546.0	3.4	54.0	7.5
01-09-18	5.7	59.0	2572.0	2.7	54.1	7.5
02-09-18	5.7	59.0	2545.0	3.4	53.3	7.4
03-09-18	5.8	58.0	2560.0	3.0	52.7	7.3
04-09-18	5.8	60.9	2549.0	3.4	55.1	7.6
Shut-in at 1200hrs.end of test						
04 to 07 Sep 18			***Shut-in test***			