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Risk Management and Contingency Planning for Well IDDP-1

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RISK MANAGEMENT AND CONTINGENCY PLANNING FOR WELL IDDP-1

Dipl.-Ing. Sebastian Homuth

A 30 credit units Master's thesis

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ABSTRACT

The Icelandic Deep Drilling Project (IDDP) is a research program designed to evaluate improvements in the efficiency and economics of geothermal energy systems by harnessing Deep Unconventional Geothermal Resources (DUGR). The goal is to generate electricity from natural supercritical hydrous geofluids from depths of around 3.5 to 5 km and temperatures of 450-600°C. At that depth, the pressure and temperature of pure water exceed the critical point of 374.15°C and 221.2 bars, which means that only a single phase fluid exists. In order to drill into the target zone of supercritical geofluids, one of the main challenges is to deal with high temperatures and pressures during the drilling and well completion processes. Because of the great uncertainties in this project a detailed risk assessment and contingency plan is necessary.

This thesis describes major geological and technical problems, in terms of drilling, in such a high temperature and pressure environment, with emphasis on the geo-engineering part of the drilling process and well completion. The natural geological risks arising from volcanic and seismic activity, as well as meeting sufficient permeable zones, are considered to be relatively minor factors when compared to the well completion process due to their low probability. The main risks are assessed in the hazard of underground pressure blowouts, meeting circulation loss zones and material failures due to the high temperature environment. In addition borehole failure, formation fracturing, cement and casing failure as well as problems during coring operations are deemed to be likely, but by applying the appropriate techniques as well as mitigation and counteractive measures, discussed in this thesis, most of these risks can be reduced or prevented.

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ABBREVIATIONS

ANSI	American National Standards Institute
API	American Petroleum Institute
ASA	American Standards Association
ASME	American Society of Mechanical Engineers
BHA	BottomHole Assembly
BHCT	BottomHole Circulation Temperature
BHP	BottomHole Pressure
BHST	BottomHole Static Temperature
BHTV	BoreHole TeleViewer
BOP	BlowOut Preventer
BPD	Boiling Point Depth
CBW	Critical Breakout Width
CO_2	Carbon Dioxide
CP	Critical Point
DTS	Distributed optical-fiber Temperature Sensing
DUGR	Deep Unconventional Geothermal Resources
E	East
EGS	Enhanced Geothermal System
H_2S	Hydrogen Sulphide
HCl	Hydrochloric acid
HDR	Hot Dry Rock
ICDP	International Continental scientific Drilling Project
IDDP	Icelandic Deep Drilling Project
ISO	International Organization of Standardization
ISOR	Iceland GeoSurvey
LCM	Lost Circulation Material
LVP	Landsvirkjun Power
M	Magnitude
MAR	Mid Atlantic Ridge
mbsl	meters below sea level
MT	MagnetoTelluric
Mt.	Mountain
MWD	Measuring While Drilling

NE	North-East
NNE	North-North-East
NORSOK	Norwegian Petroleum Drilling Standards
NVZ	Northern Volcanic Zone
NW	North-West
NZS	New Zealand Standards
pH	Concentration of hydrogen ions in solution
P-T	Pressure-Temperature
PTS	Pressure Temperature Sensor
QRA	Quantitative Risk Analysis
RES	School for Renewable Energy Science
SE	South-East
SIL	Seismic monitoring network
SISZ	South Iceland Seismic Zone
SSW	South-South-West
TEM	Transient Electromagnetic Measuring
TFZ	Tjörnes Fracture Zone
US$	United States of America Dollars
W	West

UNITS

MW_{el}	Megawatt (electrical)	Power
MPa	Mega Pascal	Pressure
bar	Bars	Pressure
m	Meters	Distance
km	Kilometers	Distance/Depth
“ (in)	Inches	Diameter
°C	Degree Celsius (Centigrade)	Temperature
mD	Milli Darcy	Permeability
m^2	Square meters	Permeability
m^3/kg	Cubic meters per kilogram	Volume rate
l/s	Liters per second	Flow rate
kg/s	Kilograms per second	Flow rate
W/m·K	Watts per meters and Kelvin	Thermal Conductivity
kJ/kg·K	Kilojouls per kilogram and Kelvin	Heat Capacity
m^3/Pas	Cubic meters per Pascal second	Transmissivity
m/Pa	Meters per Pascal	Formation Storage
Ωm	Ohm meter	Resistivity

1 INTRODUCTION

1.1 Approach of this Thesis

This thesis will give a short introduction to the Icelandic Deep Drilling Project (IDDP) and its goals, as well as a description and assessment of general geological risks in the volcanic active area of Krafla, where the first IDDP well will be drilled. In order to drill into the target zone of supercritical geofluids, one of the main challenges is to deal with high temperatures and pressures during the drilling and well completion processes. Because of the great uncertainties in this project a detailed risk assessment and contingency plan is necessary. This master's thesis will describe the major geological and technical problems, in terms of drilling, in such a high temperature and pressure environment, with emphasis on the geo-engineering part of the drilling process and well completion. Further assessment will be completed on the impact and probability of risks to the drilling process and an appropriate contingency plan will be proposed.

1.2 Cooperation Partners

This thesis was done in cooperation with the following companies and institutions:

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Prof. Dr. Axel Bjornsson and
Prof. Dr. Hrefna Kristmannsdottir (University of Akureyri)

1.3 Project Constellation

The IDDP was initiated in the year 2000 by a consortium of Icelandic energy companies. This consortium consists of Hitaveita Sudurnesja Ltd. (HS), Landsvirkjun Power (LVP), Orkuveita Reykjavikur (OR) and Orkustofnun (OS). Representatives from all involved companies constitute the Deep Vision committee, which is the steering committee of the IDDP. The first IDDP well is located in the high temperature geothermal field Krafla and will be drilled by Jarðboranir hf. (Iceland Drilling Company Ltd). All technical data processed and considered in this thesis concerning the well design and drilling process was provided by LVP and ISOR. Basic geological data for the Krafla area was provided by the University of Akureyri, ISOR and LVP.

1.4 The Icelandic Deep Drilling Project (IDDP)

The IDDP is a research program, the task of which is to evaluate improvements in the efficiency and economics of geothermal energy systems by harnessing Deep Unconventional Geothermal Resources (DUGR). The goal is to generate electricity from natural, supercritical hydrous geofluids from depths around 3.5 to 5 km and temperatures of 450-600°C. At that depth, the pressure and temperature of pure water exceed the critical point of 374.15°C and 221.2 bars, which means that the difference between water and steam disappears and instead of two phases only a single phase fluid exists. The IDDP target is to drill for supercritical fluid at point F, which is shown in fig. 1, separate that fluid by deep casings (~3.5 km) to prevent mixing with the two phase field of liquid and steam, and bring the fluid up to the surface as superheated steam.

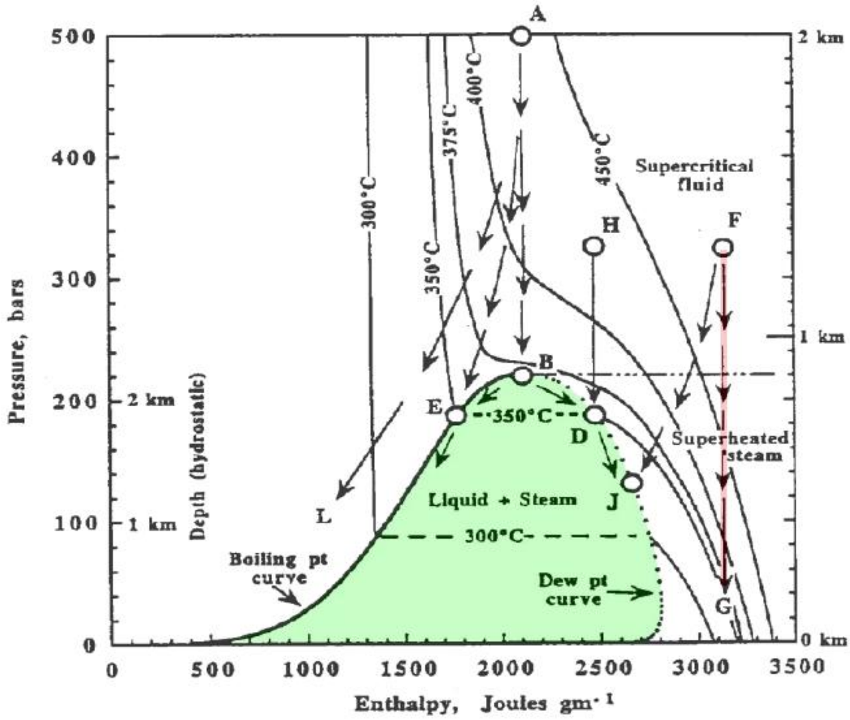

Fig. 1: Pressure-Enthalpy diagram for pure water (Fournier, 1999).

For geofluids, which contain dissolved chemical components, the critical point is elevated above those values, but will be reached in greater depths with temperatures exceeding 450°C. The concept of this program is to test and prove that the production of electricity from superheated steam derived from depressurized supercritical high-enthalpy geofluids in natural settings has economical benefits over electricity production from conventional geothermal fields. Modelling indicates that under favourable conditions, a 4-5 km deep well producing supercritical fluids at temperatures significantly greater than 450°C could yield sufficient high-enthalpy steam to generate 40-50 MW_{el}. That is an order of magnitude higher electrical power output than is usual from a conventional 2 km deep well producing from a subcritical, liquid-dominated geothermal reservoir in Iceland (Fridleifsson, 2003a). A comparison of a conventional dry-steam well and the IDDP well is given in table 1. This comparison is based on the assumption that both wells have the same volumetric flow rate of 0.67 m^3/s of incoming steam and that the supercritical fluid has a higher energy density.

Tab. 1: Comparison of conventional dry-steam wells with IDDP well (Palsson, 2007)

	Conventional dry-steam well (*)	IDDP well
Downhole temperature	235°C	430 – 550°C
Downhole pressure	30 bar	230 – 260 bar
Electric power output	5 MW_{el}	50 MW_{el}

(*) Well data taken from the geothermal field of Svartsengi

In addition to reaching supercritical conditions, another prerequisite for the IDDP well to be considered a success is to encounter sufficient permeability, such as major fractures that channel fluids from deeper heating zones.

Fig. 2: Aerial photo with boreholes and power house locations at the geothermal fields in Krafla (LVP, 2008a)

The long-term plan of the IDDP is to drill, test and produce a series of such deep boreholes in Iceland as the Krafla, Hengill and Reykjanes high temperature geothermal systems. For the first IDDP well it is proposed to drill with the conventional rotary drilling method to complete a cased well up to 3,500 m and obtain rock samples with a spot coring program that permit a proper characterization of the mostly unknown geological conditions at greater depths than 2,400 m.

The drilling site location is in ISNET 93 coordinates: X (east) = 602607, Y (north) = 581630, Z = 553; Degrees: 65° 42.953 N, 16° 45.871 W. The well's, named IDDP-1, identification number in the Orkustofnun database is 28501.

A location overview map, a geological map and a geothermal map from the Krafla area can be consulted in the appendix to this thesis.

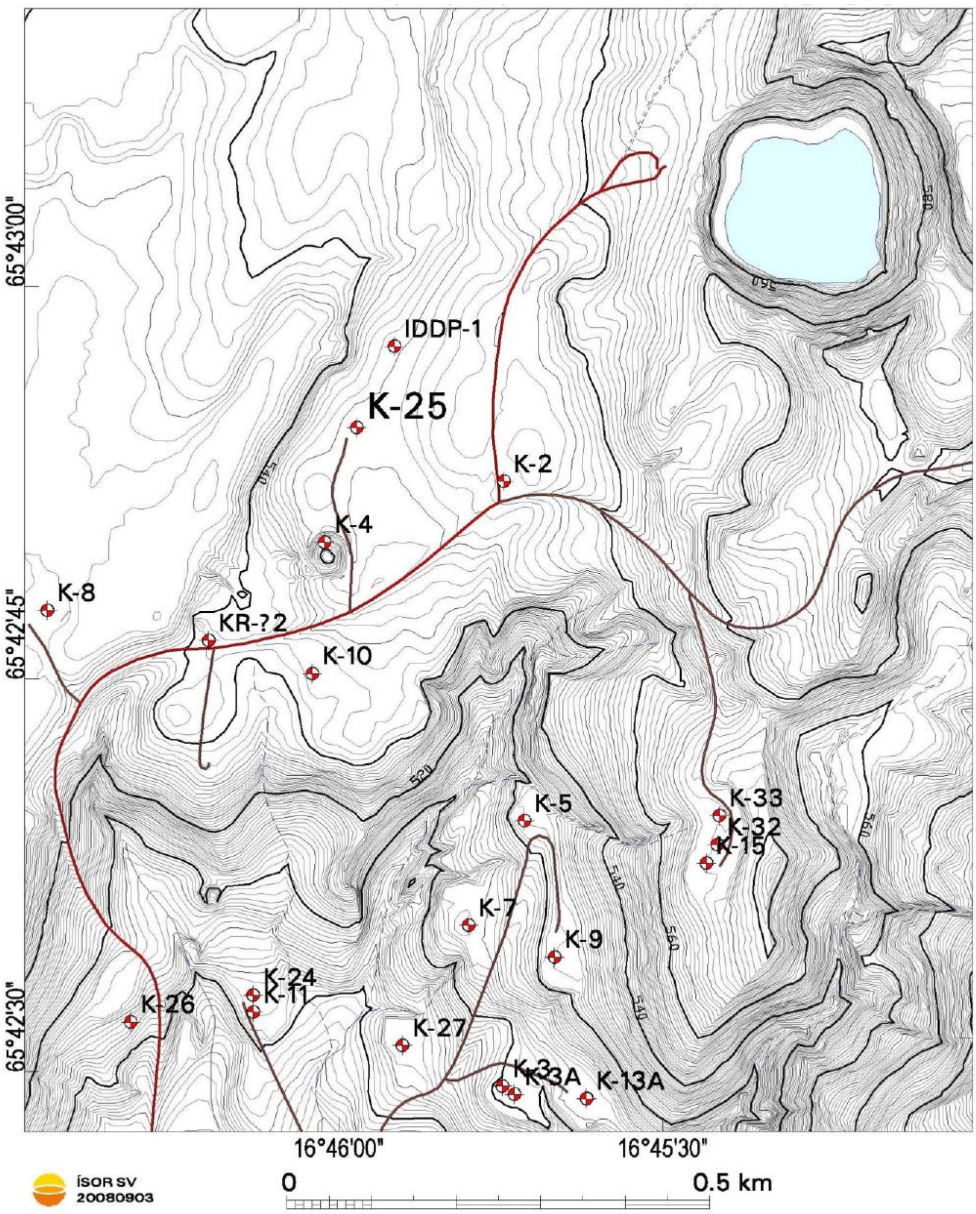

Fig. 3: Detailed overview map of the vicinity of the IDDP-1 well (Gudmundsson et al., 2008).

Besides the aim to enhance the economics of high temperature geothermal resources by producing from deep reservoirs at supercritical conditions, many of the other important scientific goals of the IDDP are listed below:

- Development of an environmentally benign, high-enthalpy energy source below currently producing geothermal fields.
- Extended lifetime of the exploited geothermal reservoirs and power generation facilities.
- Re-evaluation of the geothermal resource base.
- Industrial, educational, and economic spin-off.
- Knowledge of permeabilities within drillfields below 2 km depth.
- Knowledge of heat transfer from magma to water.
- Heat sweeping by injection of water into hot, deep wells.
- Possible extraction of valuable chemical products
- Advances in research on ocean floor hydrothermal systems

In 2006 the Deep Vision committee decided to drill the first deep borehole on the Krafla site, operated by Landsvirkjun. Hitaveita Sudurnesja and Orkuveita Reykjavíkur have also decided to drill deep boreholes on their geothermal power generating sites. All involved companies agreed to joint scientific research, by consortium, for the deep drilling borehole at Krafla and in the other areas. In July 2007, Alcoa Inc. joined the group of IDDP participants. This was followed by procurement of materials and negotiations concerning the implementation of the drilling under the supervision of LVP engineer Bjarni Pálsson (LVP, 2008b).

1.5 Drilling and Well Design for the first IDDP Well

As it is stated in the drilling contract, the plan is to drill a straight vertical well to 4,500 m. The wellhead is designed for a maximum temperature of 500°C and a pressure of 19.5 MPa. Its internal surfaces will have weld overlays clad with stainless steel to withstand acid gases and erosion, because it is expected that HCl will be found in the deep section of the well. The wellhead and its valves are to be of ANSI pressure Class 2500. The well will consist of five cemented casing strings, beginning with a 32” (inches) surface casing to 90 m followed by two intermediate casing strings, the first one with 24-1/2” to 300 m and the second with 18-5/8” to 800 m. The anchor casing with 13-5/8” diameter from top to 300 m and 13-3/8” diameter will lead down to 2400 m and the production casing with a 9-5/8” diameter to 3500 m. A 7” slotted liner will be installed in the lower open hole part of the well. For all casings, thick walled API K-55 grade steel is selected; except for the top 300 m of the anchor casing string, where an API T-95 grade steel will be installed due to its better creep resistance. Hydril/Tenaris 563 couplings and threads are designated for the anchor and production casing. For a detailed casing program schematic see chapter 5.6 and the appendix of this thesis.

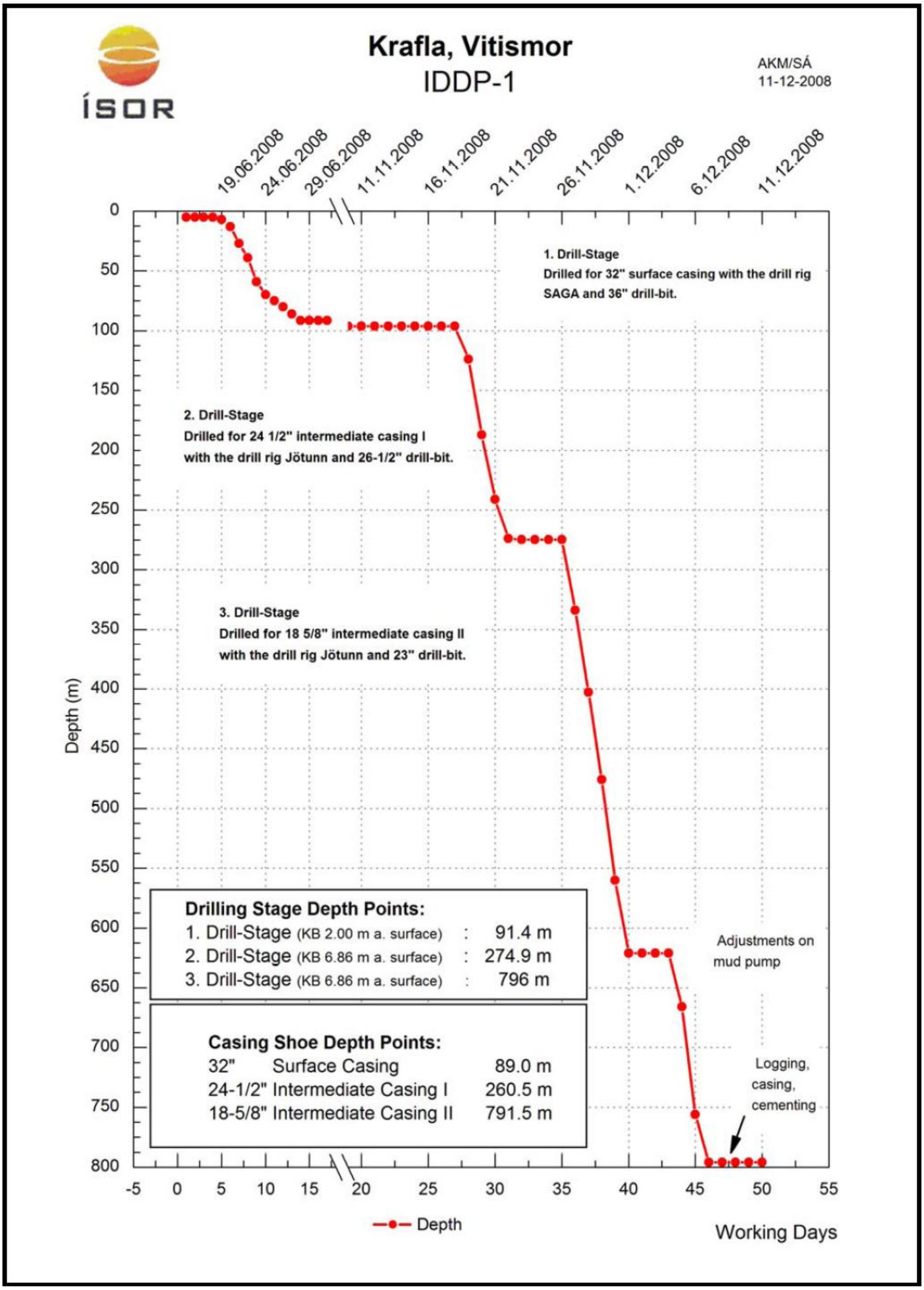

Fig. 4: Drilling work progress diagram (ISOR, 2008a)

In June 2008 the drill rig Saga drilled for and cemented the 32" surface casing to 91 m depth. In November/December 2008 the drill rig Jötunn drilled the next two sections of the well, the 24 ½" casing to 280 m, and the 18 5/8" casing to 796 m depth. The casing and cementing job was finished on the 9th of December.

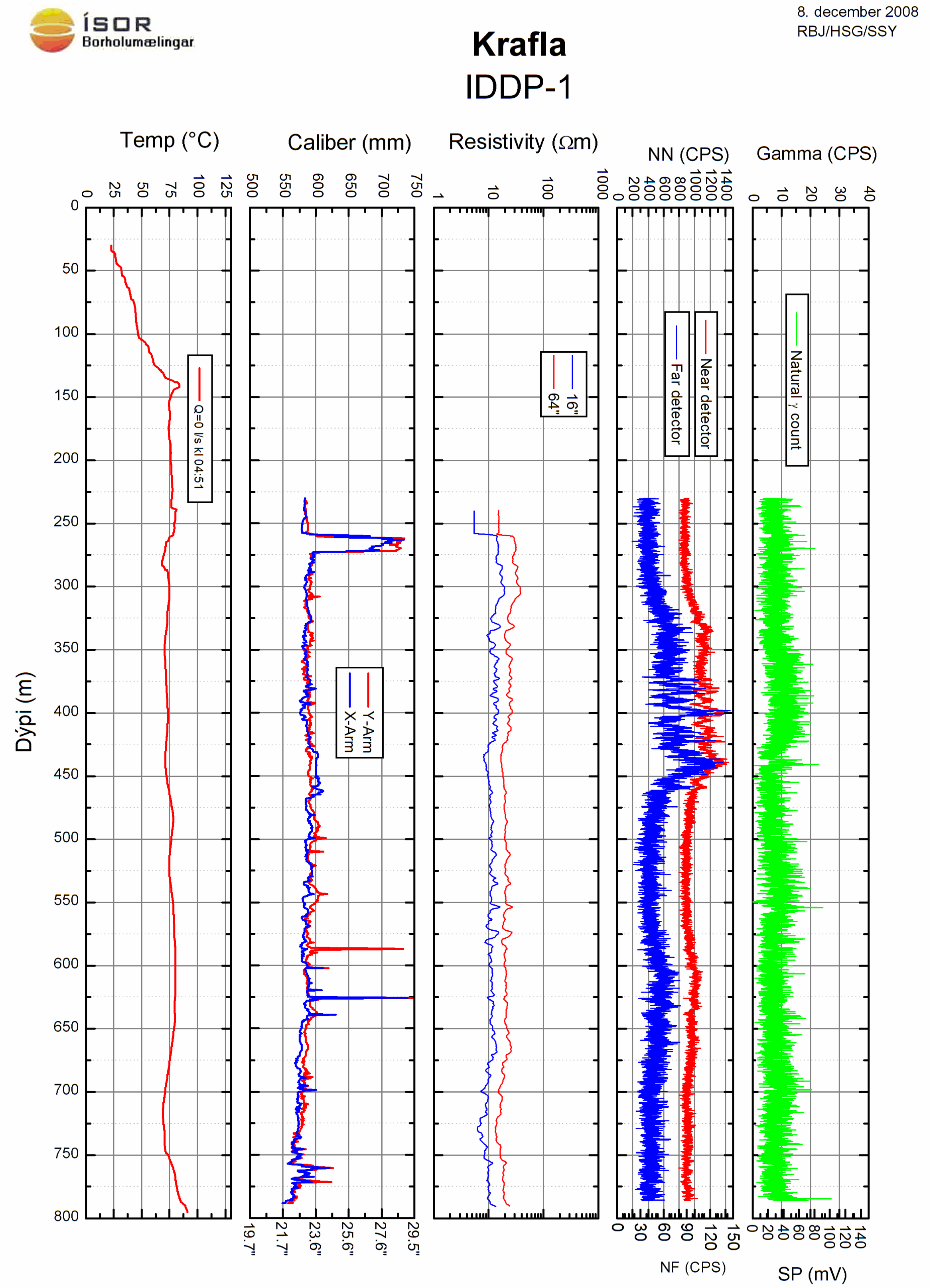

Fig. 5: Geophysical logs from the first 800 m of the IDDP-1 well (ISOR, 2008b)

All geophysical logs were performed before the casing and cementing works started. The temperature log gives a median temperature around 75°C over the first 800 m, with no circulation of fluids in the borehole. The caliper log shows only minor deviations from the desired borehole diameter. Resistivity, neutral neutron and gamma do not show noticeable abnormalities.

Tab. 2: Drilling and mud program of IDDP-1 well (LVP, 2008a)

Drilling 90-300m		**Drilling 300-800m**	
Weight on bit	4-12 tonnes	Weight on bit	7-15 tonnes
Rotational speed	20-40 rpm	Rotational speed	130-170 rpm
Flow of mud	55-70 l/s	Flow of mud	50-80 l/s
26 1/2" Bottom Hole Assembly		**23" Bottom Hole Assembly**	
26 1/2” drill bit Baker Hughes GTX-20, IADC 5-1-5		23” drill bit Baker Hughes GTX-20, IADC 5-1-5	
26 1/2” stabilizer with non-return valve		23” stabilizer	
Inclinometer 0-5°(Anderdrift)		12-1/4“ mud motor with a 21“ sleeve and check valve	
9 1/2” pony collar (6 m)		23“ stabilizer	
26 1/2” stabilizer		Inclinometer 0-5°(Anderdrift)	
Shock absorber		9-1/2” pony collar (6 m)	
5 x 9 1/2” collar		23” stabilizer	
XO - sub		Shock absorber	
1 x 8” collar		5 x 9-1/2” collars	
Drilling jar		XO - sub	
3 x 8” collars		1 x 8 “ collar	
5 x HWDP (heavy wall drill pipe)		Drilling jar	
		3 x 8” collars	
		5 x HWDP (heavy wall drill pipes)	
Mud program		**Mud program**	
Marsh funnel viscosity	50-70 s/l	Marsh funnel viscosity	50-70 s/l
pH	9.0-9.2	pH	9.0-9.2
Bentonite	50-60 kg/m^3	Bentonite	50-60 kg/m^3
Soda ash	1.5-3 kg/m^3	Soda ash	1.5-3 kg/m^3
Liquid polymer mud	as required	Liquid polymer mud	as required
Lignosulphonate	as required	Lignosulphonate	as required
Mica flakes	Loss of circulation matl.	Mica flakes	Loss of circulation matl.

The drill rig named Tyr is scheduled for the IDDP-1 well in Krafla in March 2009 and will begin by drilling a 16 ½” well from 800 m to about 2400 m depth, followed by inserting and cementing the 13 5/8” and 13 3/8“ casing. Then a 12 ¼” drilling to 3500 m including several spot cores, and cemented casing by 9 5/8” will follow. The well will be completed by an 8 ½” rotary drilling to 4500 m depth, including several spot cores. The planned schedule for the further drilling works is stated below:

March-April 2009:	Drilling for 13 3/8" casing to 2400 m
April-June 2009:	Drilling for 9 5/8" casing to 3500 m - including ~ 2 spot cores
June-July 2009:	Drilling with 8 ½" drill bit to 4500 m - including ~ 8 spot cores
Autumn 2009:	Flow test

The estimated drilling costs for the first well are approximately $20 million US.

2 RISK ASSESSMENT AND EVALUATION

A risk analysis is defined in the NORSOK standard (NORSOK, 1998) as an analysis which includes a systematic identification and description of risk to personnel, environment and assets. The ISO definition (ISO, 2002) is 'systematic use of information to identify sources and assign risk values'. The risk assessment therefore has to focus on the identification of applicable hazards and its description (including quantification) of applicable risks to the process, personnel, environment and assets.

The analytical elements of risk assessment are those that are required to identify relevant hazards and to assess the risk arising from them. These elements include all of the following aspects:

- Identification of initiating events
- Qualitative evaluation of possible causes
- Probability analysis in order to determine the probability of certain scenarios
- Consequence analysis and according mitigation and action plans

The risk assessment, which is the topic of this thesis, will begin a more general assessment and evaluation of the geological risks to the IDDP-1 well with a system description. But the main focus will be aimed at the technical aspects of the drilling process. Each determined risk will be subdivided in a description of the system; including relevant activities and operational phases, the impact on the drilling process, the probability of failure risk including the capabilities of the system in relation to its ability to tolerate failures and its vulnerability to accidental effects, and a mitigation and contingency plan.

In order to do so, a broad basis of geological, technical and well design data had to be analysed. Within these data also lays the limitation of this risk analysis. There has to be a sufficiently broad basis of relevant data for the quantification of failure frequency or failure causes, which is not always given, especially in mostly unknown geological formations with the present of supercritical geofluid. The data used usually refers to distinct phases and operations, and therefore the results can only be used to a certain extend or should not be used for other phases and operations (Vinnem, 2007). Assumptions and premises are stated in every chapter, where it was necessary to do so.

The overview table, given in chapter 6, shows the probability of the occurrence of a certain risk, a description of the impact to the IDDP-1 well completion and the possible mitigation and contingency plan measures. The probability is given as a percentage and the impact factor has a range from 1-5, where 1 means that it is only of minor importance to the drilling process and 5 implies a very severe impact. A more detailed description can be found in the following two tables. The determined percentage and impact factors are evaluated on the basis of scientific data or reasonable assumptions, which are stated in the particular chapters dealing with the specific risk assessment.

Tab. 3: Probability categories

Probability	***0-20%***	***20-50%***	***51-75%***	***76-85%***	***86-100%***
Description	very unlikely	unlikely	likely	very likely	almost sure

Tab. 4: Impact factor categories

Impact Factor	***1***	***2***	***3***	***4***	***5***
Description	negligible	minor	serious but tolerable	major	hazardous to whole project

3 GEOLOGICAL SETTING OF THE KRAFLA AREA

3.1 Geological Overview

Iceland is an elevated plateau of volcanic basalt in the North Atlantic, situated at the junction between the Mid-Atlantic-Ridge (MAR) which defines the plate boundaries of the American and the Eurasian plate and the elevated Greenland–Iceland–Faeroes Ridge. The spreading rate near Iceland is about 1cm per year in each direction, based on magnetic anomalies to the north and south of Iceland. The general spreading direction is N100°E. The Greenland-Iceland-Faeroes ridge is thought to be the trail of a mantle plume located beneath Iceland which has been active from the time of opening of the North-Atlantic some 50 Ma ago (Björnsson, 2007). The mantle plume is now situated below central East-Iceland, within the eastern branch of the volcanic rift-zone which crosses Iceland from southwest to northeast. The axial rift zone crosses Iceland from the Reykjanes Peninsula where it connects with the Reykjanes Ridge over transform fault zones. The Tjörnes Fracture Zone (TFZ) in the northeast and the South Iceland Seismic Zone in the south (SISZ) connect the presently active spreading zones with the submarine ridge segments (Fig. 6). The Northern Volcanic Zone in Iceland (NVZ) and its geothermal areas are continuously being deformed due to their location on the boundary between the North-American and Eurasian plates.

The high temperature geothermal system of Krafla was chosen as the first drill site for the IDDP project based on intensive geophysical and geological exploration, which took place within the whole Krafla vicinity, so this area is better known than any other considered geothermal system in Iceland. The geothermal field of Krafla is located in the north-eastern part of Iceland within the Krafla Central Volcano complex. The geology of this area is obviously dominated by the presence of the Krafla central volcano, which features a caldera and an active NNE trending fissure swarm crossing the caldera. About 100.000 years ago, at the end of the last interglacial, a large (some km^3), explosive eruption of intermediate to acidic composition resulted in the formation of the Krafla caldera, which has dimensions of 8 by 10 km. During the last glacial period the caldera was more or less filled with volcanic material, and subsided some hundred meters. At the same time the fissure swarm crossing the center widened by some tenths of meters every 10 thousand years, resulting in the elliptical shape of the caldera (Saemundsson 1991).

Some major lithological units have been identified, including two hyaloclastite units reaching to depths of 800–1000 m separated by basaltic lavas, underlain by a lava succession to 1100–1400 m depth, which sometimes has thick hyaloclastite interbeds. Small basaltic and dolerite intrusions forming dykes and sills are common in the lava succession. Below 1100 and 1400 m depth they dominate the succession. Below 1800 m the small intrusions are replaced by larger intrusive bodies of gabbros and occasional granophyres. The deeper lithology is mostly unknown. The intrusive rock intensity is 80–100 % below 1500 m in most sections of the Krafla field, and involves both gabbros, and coarse grained acid rocks (granophyres) which are much harder than the basaltic gabbros or dolerites (Fridleifsson, 2006). Also intrusions of andesitic composition can be expected and one would expect relatively narrow fractures at intrusive rock contacts within the complex. Most of such fractures have already sealed by secondary minerals.

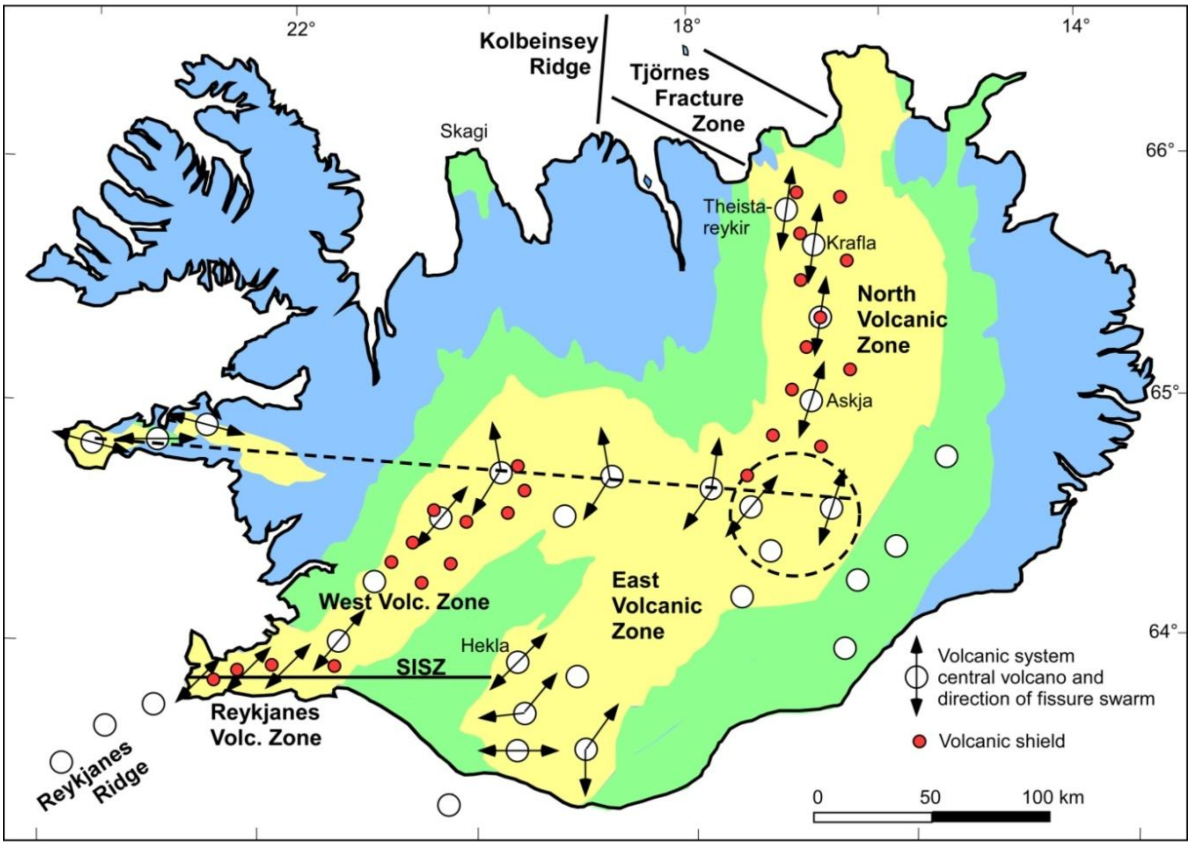

Fig. 6: Simplified geological map of Iceland. Yellow area: volcano-tectonic zone younger than 0.8 Ma, green area: bedrock 0.8-3.3 Ma old, blue area: Tertiary bedrock with age up to 16 Ma. Open circles: central volcanoes, arrows: direction of the associated fissure swarms, filled red circles: large olivine-tholeiite lava shields. Heavy or dotted lines: transform faults. Dotted circle: proposed location of the mantle plume beneath the island. SISZ: South Iceland Seismic Zone. The map is modified from Saemundsson, 1978.

The heat source for this geothermal system is a well determined magma chamber, which was identified with S-wave attenuation at relatively shallow depths between 3 to 8 km during the 1975-1984 volcanic activity (Einarsson, 1978), which is known as the "Krafla Fires". This last eruptive period resulted in 21 tectonic events and 9 explosive eruptions (Björnsson, 1985 & Einarsson, 1991). The hypothesis of a solidifying magma chamber under the Krafla volcano inferred from the measurements by Einarsson are confirmed by accumulated well field data on gas emissions and temperature distributions.

3.2 Structure of Krafla Area

The fissure swarm that intersects the Krafla caldera, which was formed about 100 thousand years ago, is 5–8 km wide and about 100 km long (Saemundsson, 1974, 1978, 1983). Two other fracture systems have been identified in the Krafla area. The caldera rim reveals curved tectonic. The Hvitholar drilling field is where the caldera rim and the NNE trending fissures cross. WNW–ESE trending fissures are exposed in the Sudurhlidar wellfield and have been related to intrusive activity into the roots of the central volcano (Saemundsson, 1983; Arnason et al., 1984).

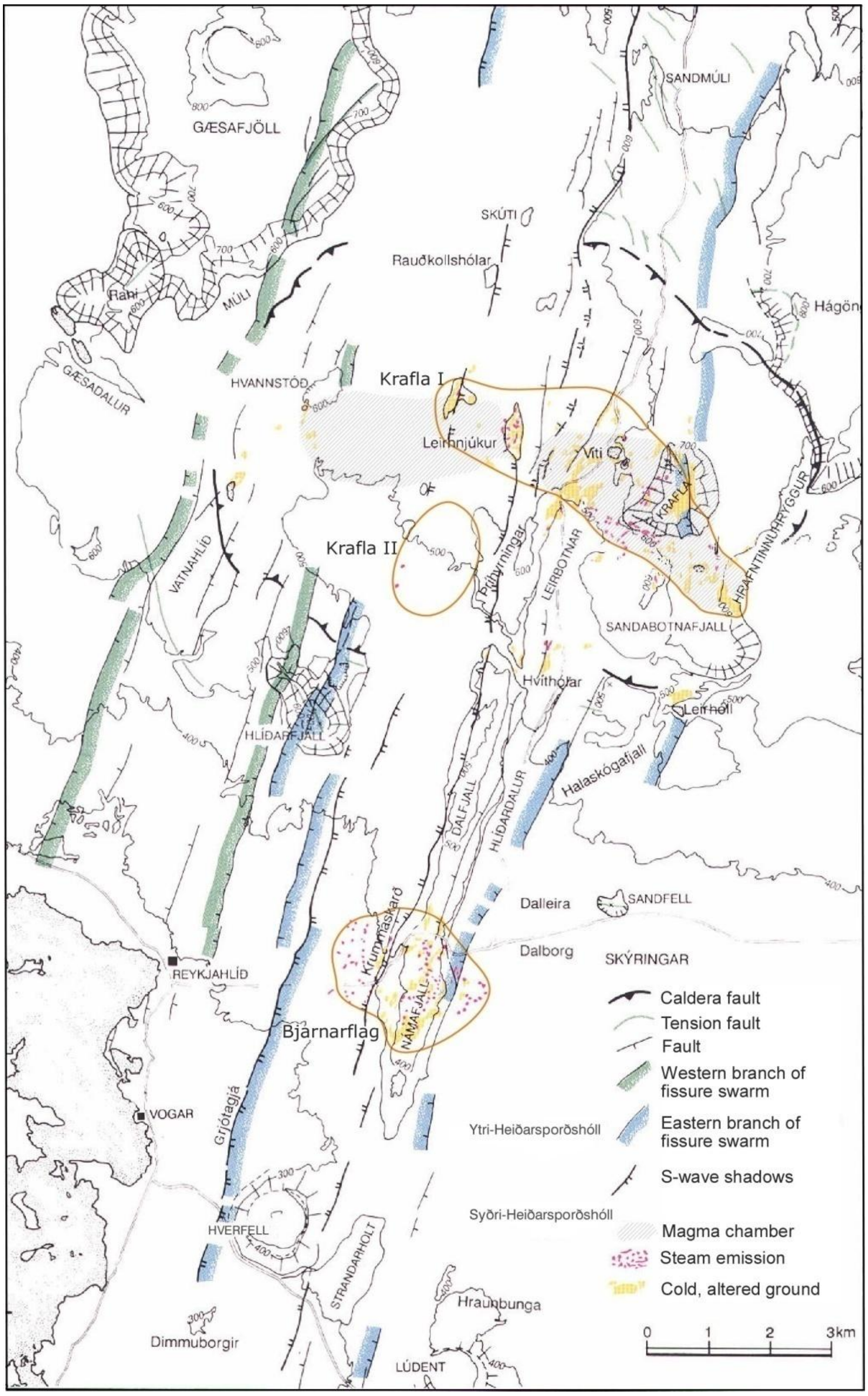

Fig. 7: Central part of the Krafla volcanic system showing the caldera and the fissure swarm which traverses it (Saemundsson, 1991).

The volcanic active zone crosses the caldera at the divergent plate boundaries where Leirhnjukur is in the center. During the Krafla fires large scale faulting extended north and south from Leirhnjúkur and intersected volcanic eruption sites. Early in the volcanic period a NNW-SSE trending normal fault displaced the south slope of Mt. Krafla as well as fumaroles became active on it.

Geothermal manifestations are mainly concentrated on the western and southern slopes of Mt. Krafla and at Leirhnjúkur in the center of the caldera. The activity is manifested in the form of mud pools and fumaroles with minor sulphur deposition. Most of these manifestations are fault controlled, but some of the larger fumaroles are associated with explosion craters. At Leirhnjúkur, in the center of the caldera, the fumaroles and mud pools follow the trace of closely spaced eruptive fissures, among them the two youngest ones, which erupted during the Mývatn and Krafla fires 280 and 30 years ago (Björnsson et al., 2007). During both volcanic episodes the geothermal surface activity increased significantly. Minor surface manifestations occur at the southeast margin of the caldera.

The drilled area at Krafla has been divided into four wellfields: Leirbotnar, Sudurhlidar, Hvitholar and Vitismor, where the IDDP-1 (north of well 25) well is located.

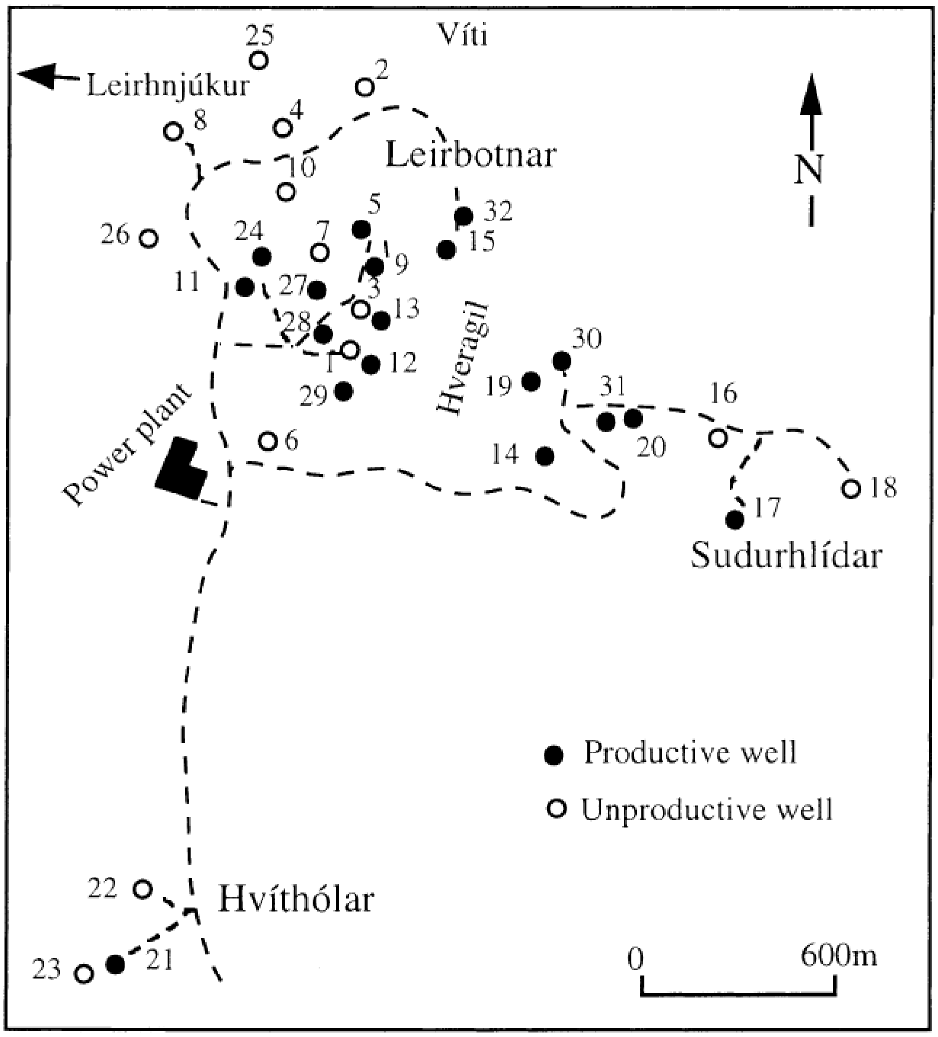

Fig. 8: Wellfield and well locatio in Krafla (Gudmundsson & Arnorsson, 2002)

4 GEOLOGICAL RISKS

In this chapter the major geological risks, like hazards from volcanic eruptions and earthquake activity and meeting sufficient permeable zones, are discusssed. Because of the close relationship between volcanic euptions and ground movements the risk assessment for both seismic active processes is summarized in chapter 4.2.1 and 4.2.2. Due to the complex chemical rock-geofluid interaction and the limited geochemical data concerning supercritical fluids from high temperature and high pressure geothermal fields, the assessment of the influences of those fluids on the drilling operation and resulting hazards would go beyond the scope of this thesis and is therefore not discussed here. But it shall be noted that the chemical composition of the geofluid and its acidic nature is one of the major concerns to the IDDP-1 well completion.

4.1 Volcanic Hazards

To quantify volcanic hazards a study of the eruption history and past events of a dormant volcano can give a good estimate of the long-term probability of renewed activity. The rifting events which took place at Krafla from 1975-1984 and subsequent volcano inflation until 1989 have been followed by no eruptive activity in the area. No known magma accumulation is taking place at a shallow depth in the crust, but magma accumulation near the crust-mantle boundary has been suggested, or alternatively that signal may relate to post-rifting adjustments (Björnsson et al., 2007). Geodetic measurements indicate a relatively uniform strain accumulation along the length of the plate boundary in north Iceland and suggest that the Askja segment adjacent to Krafla should be considered as the likely location of renewed activity. Inferred from the last eruptive events, the eruptive phases of the Krafla vulcano are episodic and occur at 250-1000 year intervals, while each eruptive phase apparently lasts 10-20 years.
Based on the minimum recurrence intervals of about 250 years in earlier episodes, and the fact that it takes time to build up sufficient tensional stress for a new episode, the Krafla system is considered comparatively safe for utilization- during this century at least. It stands to reason that existing wells, as well as production wells, may be affected by ground movements. Partial collapse that may block the wells is a possibility, but seismic action is not known to have severely damaged production wells in Iceland, except on one occasion when a fracture passed through a well in Bjarnarflag during the Krafla fires. It is also known that volcanic action did damage wells located inside the central graben during the Krafla fires.

Ash-fall from distal volcanoes cannot be excluded as a potential hazard, however large plinian eruptions are rare. Phreatic eruptions from sub-glacial eruptions are more common in Iceland, but only a few have caused heavy ash-fall in NE-Iceland.

In terms of hazardous floods caused by volcanic eruptions, the geothermal areas of the northern NVZ are out of reach of catastrophic floods due to the volcanic melting of glacier ice.

4.2 Earthquake Hazard

The fundamental database is earthquake catalogues used to determine where, how often and how big earthquakes are likely to be. Unfortunately the related statistics are generally based on geologically short catalogues. Therefore, the information from seismic monitoring, historic records, geodetic monitoring, and geological records are combined to characterize seismic sources. These data, if available, are used in a geophysical interpretation of seismic source zones. However, large uncertainties are often associated with the interpretation of source characterization.

The biggest tectonic earthquakes in and around Iceland occur in the transverse zones in south (SISZ) and north Iceland and may reach at least magnitude seven. In northeast Iceland earthquakes occur mainly within the Tjörnes Fracture Zone. In the spreading volcanic zones magnitudes are smaller and usually do not exceed 5. This is due to the fact that the elastic crust is presumably only 5-10 km thick in the volcanic rift zones and the temperature gradient is high. In the transform zones (TFZ and SISZ) the elastic crust is thicker, some 10-15 km, and the temperature gradient lower. Volcanic earthquakes located in the vicinity of the major volcanoes usually do not exceed magnitudes 4-5. Small earthquakes, which occur quite frequently in high-temperature geothermal areas, usually do not exceed magnitude three.

In northern Iceland, the SIL seismic monitoring system has been in operation since 1994 (Stefánsson et al., 1993). During this period, seismic activity within the region has remained low, with the largest earthquake registering 2.6 on the Richter scale. A complete catalogue exists for earthquakes exceeding magnitude 1.2. Within the period of the operation of the SIL seismic network, 116 events with a magnitude above 1.2 have been detected in the area; yielding a b-value of 1.21 ± 0.22 (see fig. 9). The b-value is the relation between earthquake size and the frequency of occurrence, which is represented by:

$$\log N = a - b \cdot M \qquad [1]$$

where N is the number of earthquakes ≥ M. The maximum likelihood estimate of b is

$$b = \frac{0.4343}{(M_m - M_{min})} \pm \frac{1.96b}{\sqrt{n}} \qquad [2] \qquad - for\ 95\%\ confidence$$

were M_m is the mean magnitude for all events with magnitudes above or equal M_{min}, and n is the number of events (Aki, 1965).

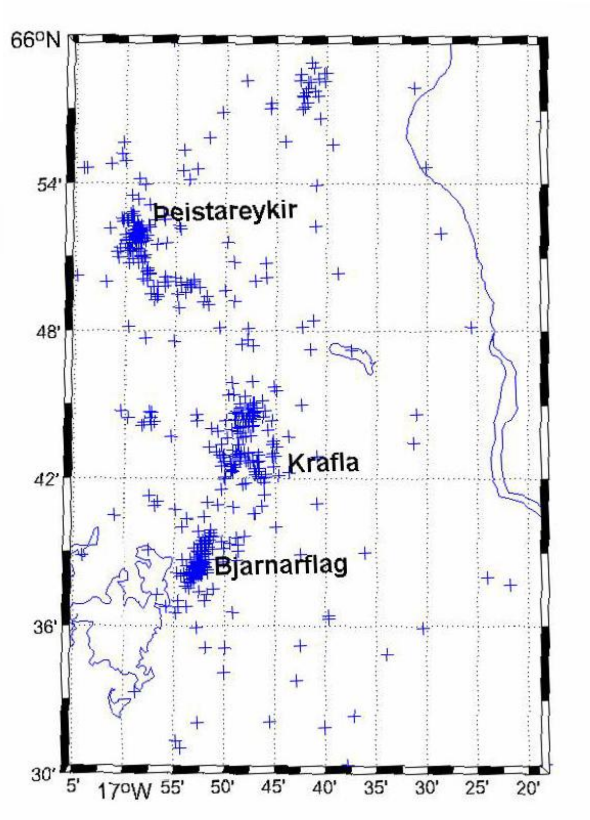

Fig. 9: Locations of events ≥ 1.2 since 1994 (Björnsson et al., 2007).

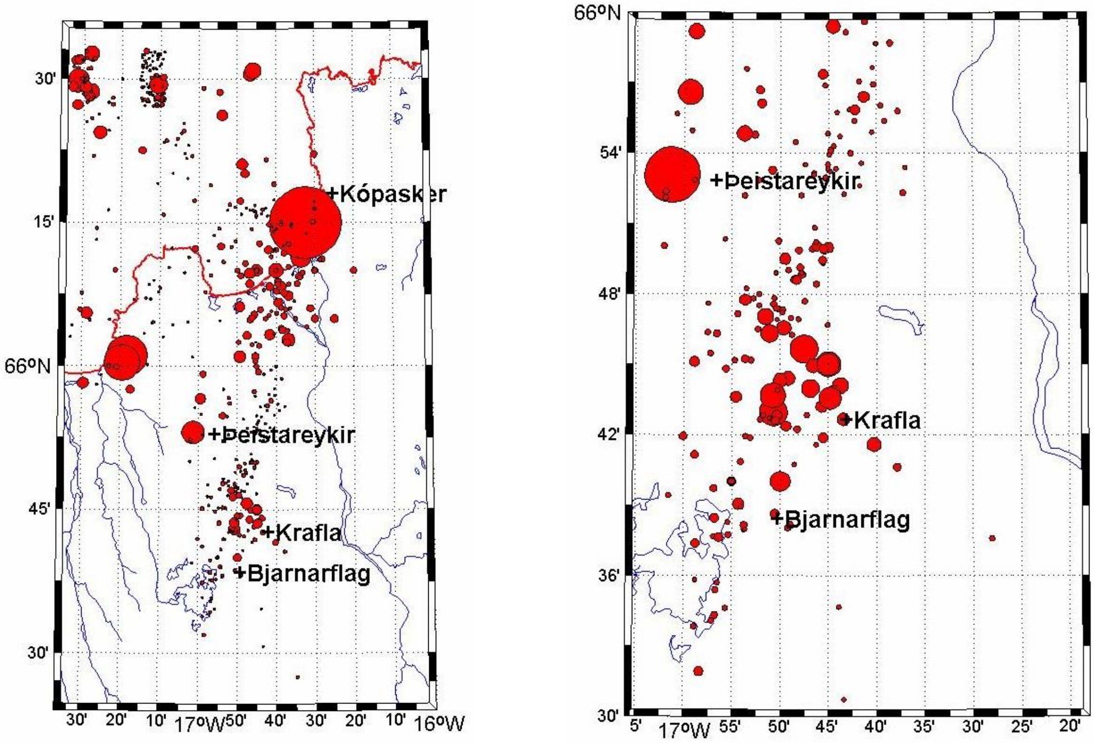

Fig. 10: Measured earthquakes (M ≥ 3) in the NE-region from 1930 to 2000. Right: Overview of NE Iceland, Left: more detailed view at the Krafla area (Björnsson et al., 2007).

Earthquake hazards are commonly estimated using b-values. The estimation is based on the assumption that the value is stable, but many studies have demonstrated variations in the b-value over time. In the vicinity of Krafla, a significant change between the periods before and after 1975, from $b \approx 0.9 \pm 0.2$ to $b \approx 1.2 \pm 0.2$ could be observed. A weak crust that is incapable of sustaining high strain and heterogeneous stresses could be a plausible explanation for the higher b-values after the 1975 event. The lower b-value before the last rifting episode indicates that the crust has stabilized during the 200 years since the 1724 – 1746 rifting episode (Björnsson et al., 2007). Therefore, in the following decades, a b-value of 1.0 is a conservative value for a hazard estimation in the area. Consequently, the probability of a magnitude 5 earthquake is considered to be low.
One of the quantities needed in engineering analysis and earthquake resistant design of structures is the duration of strong shaking during earthquakes. An estimate of duration is required as an input into probabilistic analysis. Figure 11 gives the relative significant duration as a function of distance to surface trace of the causative fault for different earthquake magnitude values. From figure 11 one can also see that the relative significant duration in the near fault area is not expected to exceed 10 s on average.

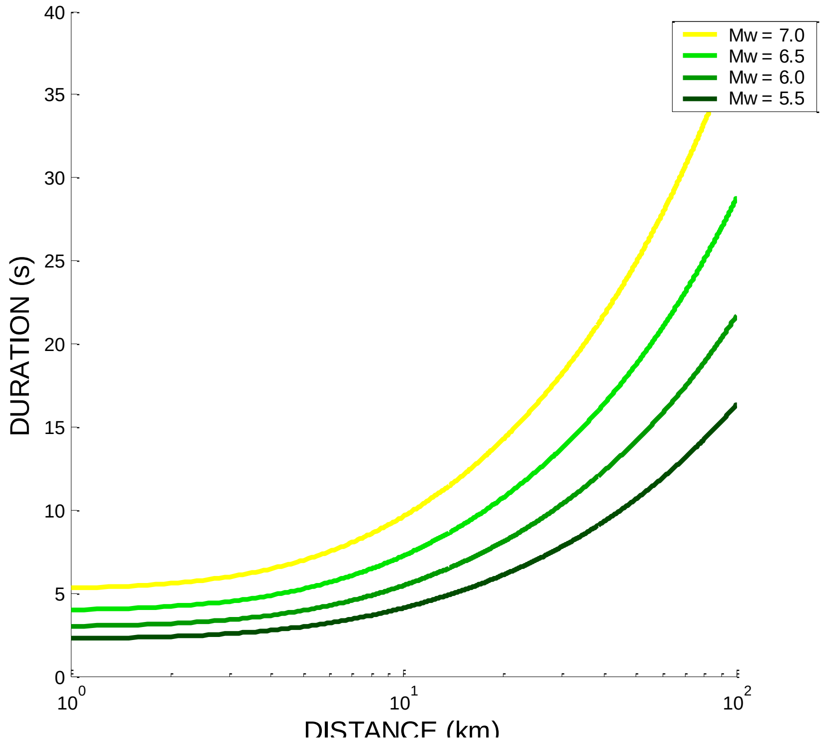

Fig. 11: Duration of earthquake as a function of distance to surface trace of causative fault for different magnitude values (Björnsson et al., 2007).

Inferred from the 1975 – 1984 rifting episode in the Krafla area, it is possible that seismic movements might have released accumulated stresses in the region. The accumulated moment since 1872 is estimated at 3.1×10^{19} Nm. One can calculate that, if this energy were released in one earthquake, the corresponding moment magnitude (M_w) would be 6.9 at maximum (Björnsson et al., 2007). It is therefore plausible to assume a future earthquake magnitude of 6.5 in the eastern part of the fault with a likely epicentre near to Höskuldsvatn.

From the minimum recurrence intervals of earlier episodes of about 250 years, and the fact that it takes time to build up sufficient tensional stress for a new episode, the Krafla system is considered comparatively safe for utilization- during this century at least. Since the early postglacial time, inter rifting volcanic eruptions due to overpressure in Kraflas magma chamber are not known to have occurred. The production area and power station of Krafla is located east of the main activity of the fissure swarm and therefore not directly affected. There is a small concern that the two fissure swarms will experience a new rifting episode in the near future, possibly in the next 100 or even 200 years, because the northern part of the NVZ may be regarded as having been "reset" with regard to stress accumulation during the Krafla fires (Björnsson et al., 2007). For the Krafla swarm, this is concluded from the large strain release that occurred.

4.2.1 Risk Probability

In general it is concluded, that a rifting episode in the NVZ as a whole can be expected roughly once every century and in the case of Krafla the rifting episodes may be accompanied by a volcanic eruption. Deformations are expected at Krafla during such inter-rifting periods. Local magmatic and geothermal pressure sources are known to have contributed continuously to deformation processes at Krafla in the past decades. Deformation due to pressure variations in the shallow magma chamber at the Krafla volcanic system may be expected, as well as deformation due to exploitation and other processes in the geothermal fields. They can cause deformation at a rate of up to the maximum of a few centimeters per year (Björnsson et al., 2007).

As stated above the Krafla system is considered comparatively safe in terms of volcanic activity and major ground movements during this century. Therefore the probability for such an event happening, especially during the drilling operation, is assessed as a minor risk with a probability of occurrence less than 20 %.

4.2.2 Impact on Drilling Operation and Prevention Measures

A volcanic eruption as well as a major earthquake (Magnitude considerably above 3) can cause severe damage to the drilling rig, the working crew and of course the wellbore. On that account the impact of both the geological risks on the drilling process and well completion is considered to be very significant. Possible consequences are ash deposits, mast collapse, water and electricity supply failure, access difficulties, fires on the drilling rig, engine failures, blowouts and wellbore collapse. Both geological risks are assessed with a high impact factor. In terms of volcanic hazards the factor is 5, in terms of earthquake hazards the factor is assessed at 4.

Due to the fact that there are no measures to prevent an earthquake or volcanic eruption it is important to observe and monitor the seismic activity not only in the Krafla region but also in other volcanic vicinities in the catchment area of Krafla. This is done by a seismic monitoring system with geophones distributed all over Iceland. Therefore it is possible to alert the drilling crew in case of increased seismic activity at the early stages of an expected earthquake. The drilling crew’s task is then to secure the drill rig and additional well material, and if there is enough time to seal the well, or even abandon the drill site.

4.3 Permeability

Because of the very limited data concerning the permeability in the Vitismor wellfield a study from the wellfield Leirbotnar next to the IDDP-1 drillsite is used to estimate probable permeabilities. Numerical simulation studies of the generating capacity of the geothermal reservoir in Krafla, described by Bödvarsson et al. (1984a,b,c), reveal that the average transmissivity is low. The Krafla model described by Bödvarsson et al. (1984) comprised a vertical cross section which included both Leirbotnar and Sudurlidar well fields. The simulation model is in agreement with the assumption that the reservoir system is controlled by two upflow zones: one at Hveragil and the other very close to the eastern border of Sudurhlidar. The lower reservoirs in Leirbotnar and Sudurhlidar are two phase, with average vapour saturation of 10-20% in the fracture system. The porosity of the reservoir was assumed to be 7%. The permeability of the reservoir was about 1-4 milli Darcy (mD) with an average of 2.0 mD (= $1.97 \cdot 10^{-15}$ m^2). The values for this transmissivity were obtained from detailed analysis of injection tests. The permeability seems to be controlled by vertical fractures rather than by horizontal zones. The best match with well flow data was obtained when assuming high vertical permeability.

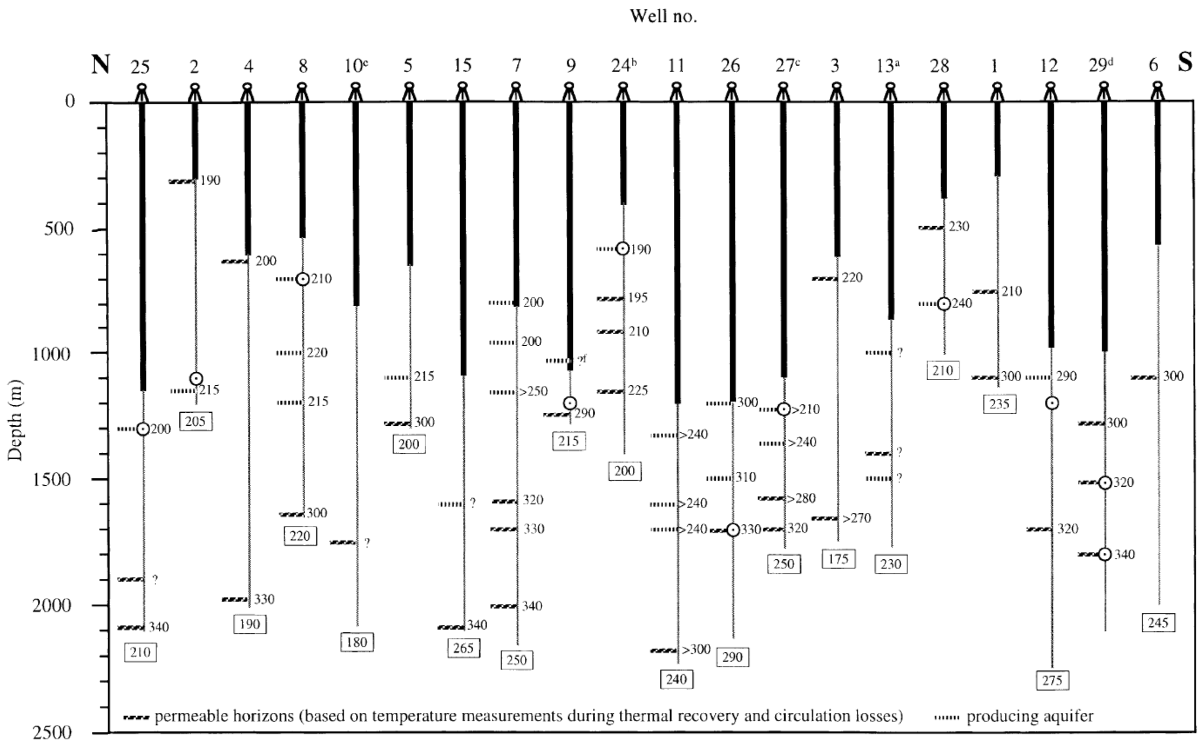

Fig. 12: Permeable horizons intersected by wells in the Leirbotnar field in Krafla with temperatures in °C inferred from downhole measurements. Thick line indicates production casing, circles indicate pivot point, numbers in boxes give the average geothermetry temperature (solute and H_2S) (Gudmundsson & Arnorsson, 2002).

It was also necessary to assume that the permeability in the upflow zones at Hveragil and Sudurhlidar is one order of magnitude higher than the average value for the reservoirs. Therefore the permeability of up flow channels at Hveragil and Sudurhlidar is estimated as 30 mD (= $3.29 \cdot 10^{-11}$ m^2). Fluids from the up flow channel recharge the reservoir at an estimated rate of 10 kg/s. The two phase fluid mixture flows laterally along highly permeable fractured zones at a depth of 1 km and mixes with the upflow at Hveragil.

The thermal conductivity of the mostly basaltic rocks was determined as 2.2 W/m·K and the heat capacity is 1 kJ/kg·K.

Sample No.	Well No.	Permeable horizons. Depth (m)/temp.(°C)	Geothermometry temperatures (°C)						Average (°C)	Pivot point. Depth (m)
			SiO_2	Na/K	Na/K/Ca	CO_2	H_2S	H_2		
98-3205	K-5	1100/215, 1270/300	209	189	192	261	215	262[a]	200	
98-3212	K-9	1250/290	244	215	212	218	195	190	215	1100
98-3206	K-11	1330/>240, 1600/>240, 1700/>240, 2180/>300	250	237	228	293	248	292	240	
97-3101	K-12	1100/290, 1700/320	284	272	238	343	267	282	275	1200–1400
97-3102	K-13	1000/?, 1400/?, 1500/?	234	205	209	314	265	299	230	
98-3207	K-13		227	202	208	308	263	314	225	
97-3099	K-14	900/?, 1100/290, 2050/330	250	232	224	349	272	317	245	1000–1100
97-3104	K-15	1600/?, 2070/340	287	266	249	325	277	302	265	1600
98-3204	K-17	1000/290, 1900/290	274	267	262	297	264	327	275	
[b]	K-19	1000/?, 1200/>240, 2100/340	249	245	246	>350	271	315	245	1200
97-3100	K-20	700/240, 1200/290, 1500/300	288	280	264	>350	280	309	280	1100–1200
98-3203	K-20		289	283	268	>350	278	319	280	
97-3098	K-21	400/?, 570/260, 930/190, 980/180, 1150/170	256	236	224	263	250	282	245	600–800
98-3201	K-21		253	233	231	297	267	<0	245	
98-3208	K-24	580/190, 780/195, 920/210, 1150/225	208	<0	187	263	227	<0	200	600–700
98-3209	K-27	1220/>210, 1360/>240, 1570/>280, 1700/320	266	252	232	282	251	305	250	1100–1200
97-3103	K-28	500/230, 800/240	235	213	210	240	180	185	210	800
98-3210	K-28		236	205	208					
97-3105	K-30	1200/300, 1550/315, 1750/>300	304	298	270	>350	290	281	290	1500
97-3110	N-04	700/?, 900/280	241	223	205	251	275	335	240	
97-3109	N-11	1280/310, 1450/320, 1800/290	260	252	243	261	279	337	260	1400
97-3108	N-12	1400/>300, 1700/>280, 1800/>290	241	247	238	276	285	>350	250	1400

[a] This value is anomalously high compared to H_2-temperatures for older samples (see Fig. 6a).
[b] Based on chemical analysis from Hauksson and Benjamínsson (1997)

Fig. 13: Permeable horizons, detailed geothermometry temperatures and location of pivot points in different wells in Krafla, average of the solute and H_2S geothermometry temperatures (Gudmundsson & Arnorsson, 2002).

In general, circulation loss zones are perhaps the best indicators of permeability. These zones commonly appear as localized lows in temperature logs- a phenomenon reflecting slow thermal recovery following invasion by cool drilling fluids. Where a fracture coincides with such a low temperature it is assumed to be permeable. Injection tests in well KG-25 showed that the correlation between the measurements and the used model was very close. The transmissivity was estimated $3.2 \cdot 10^{-8}$ m^3/Pas, the formation storage $8.8 \cdot 10^{-8}$ m/Pa and the skin effect +0.2 (Gudmundsson et al., 2008). Compared to other wells in the Krafla area the transmissivity of well KG-25 is above average.

4.3.1 Risk Probability

The risk of not meeting a sufficient permeability increases with greater depth due to the higher litho static pressure, which favours the closure of existing fractures. But on the other hand the increased transmissivity in the Vitismor well field and the experience with other ultra deep wells like the WD-1 well in Japan showed that permeable horizons can occur in great depth, as long as the brittle-plastic boundary of the basalt rock is not reached. Investigations on the WD-1 well in Japan demonstrated that the brittle-plastic boundary constrains the maximum depth of fracturing. The results from the new MT-study by Arnason et al. in 2008 (see also page 44) allow the presumption that the beginning of the brittle-ductile transition zone is located somewhere in the depth range of 4-5 km, which is the target area of the IDDP-1 well. That leads to the conclusion that the probability of not meeting a sufficient permeable horizon in depths below 4000 m is assessed to be 50%.

4.3.2 Impact on IDDP

If no sufficient permeable horizon intersects with the drill path and no charging of supercritical fluids is possible, the whole project is put at risk, unless cost-intensive side tracking is not considered. Consequently the impact factor is assessed at 4. To have further options at that point in the project it is necessary to investigate possible upper feed zones while drilling, before sealing them out, in case it is necessary to penetrate the casing at that depth interval again. It might also be worthwhile to think about possible reservoir enhancement methods like hydraulic fracturing.

4.3.3 Concept for Reservoir Enhancement (if desirable or necessary)

Different stimulation techniques can be considered, depending on the number, thickness, lithology and spatial distribution of the potential reservoir sequences. One precondition is that the reservoir fracture zones should be tapped with an optimal drill path orientated on the basis of geophysical surveys. In igneous rocks, hydrofracs certainly are the most promising procedure. Hydraulic stimulation concepts were originally designed and applied to geothermal wells of HDR or EGS projects in crystalline rocks. From the results of hydraulic fracturing in geothermal projects it is concluded that hydraulic fracturing is more effective in crystalline rocks compared to sedimentary rocks. In order to design hydraulic stimulations a multitude of reservoir parameters need to be known. Most important is a good knowledge of petrophysical rock properties and in-situ-stress conditions (Kreuter & Hecht, 2007). Moreover it is important to have a good understanding of reservoir geometries, preferably in three dimensions.

5 DRILLING RISKS

Drilling is one of the areas in which geothermal resource development has benefitted considerably from the expertise of the oil and gas industry. Drilling for geothermal energy is quite similar to drilling for oil and gas. But there are some key differences due to the high temperatures associated with geothermal wells, which affect the circulation system and the cementing procedures as well as the design of the drill string and casing.

To assess the risks of drilling due to supercritical geofluids, the effects of drilling activities on the temperature–pressure conditions in the well-adjacent formations and inside the well must be combined with behaviour models of supercritical geofluid capable of predicting when supercritical conditions occur. Since some of these behaviour models of supercritical phases are currently not well established and/or efforts of current research, these models and pressure–temperature simulations require knowledge about input parameters that are associated with considerable uncertainty. Also the long term consequences on materials of being exposed to supercritical geofluids are unknown. These preconditions have to be considered while reading the following chapters.

5.1 High Temperature and Pressure Environment

To estimate the pressure and temperature (P-T) conditions in the IDDP-1 well it makes sense to have a look at well data from nearby wells and wells which reach the deepest depths in the high temperature geothermal field of Krafla. The temperature increases with depth and follows what is referred to as the "boiling-point depth curve" (BPD). Therefore we can use the P-T data from well KG-25, KG-04 and KG-10 as a guide to infer that in the IDDP well, conditions should follow the BPD-curve until the critical point is reached at about 3.5 km depth. It is planned to cement the casing at approximately 3.5 km depth. Thus supercritical rock temperatures and pressures should be reached soon after drilling below the casing. But also the possibility of conditions exceeding the BPD-curve at a shallower depth needs to be considered. This could be a likely scenario, which already occurred in well NJ-11 at Nesjavellir in 1985, where the temperatures below 2200 m certainly surpassed the conditions determined by the BPD-curve, and involved superheated steam at least hotter than 380°C, if not supercritical conditions as suggested by Steingrímsson, et al. (1990). In 2008 these conditions were found in well KJ-39, which is an inclined 2800 m deep well located in the south of the Leirbotnar field with a measured maximum temperature of 386°C in ca. 2400 m depth. In this case it was actually drilled into lava. The drill bit showed after recovery to the surface adhesion of fresh formed glassy basalt. Geophysical measurements of the vicinity of well KJ-39 showed no indication of elevated magma in this area (Palsson, 2008, pers. comm.), which illustrates again the great uncertainties in this project. Therefore during the drilling and completion process of the IDDP-1 well at the Vitismor field, one should be prepared for P-T conditions surpassing the BPD-curve. However, in the case of borehole KJ-39, the drilling crew was able to control the well and set a cement plug, which shows that even those critical conditions can be handled.

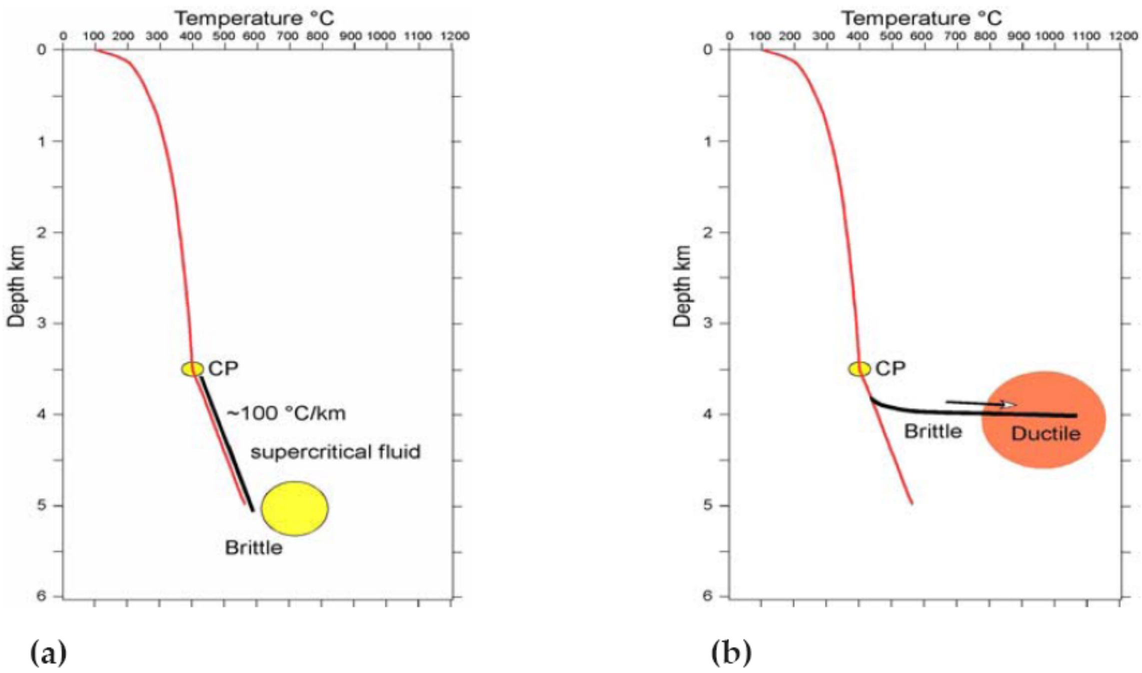

Fig. 14: Possible temperature scenarios for the IDDP-1 well around a cooling intrusion at Mt. Krafla. (a): along a margin, (b): into the top of the magma chamber at app. 4 km depth (Fridleifsson et al. 2003 a,b).

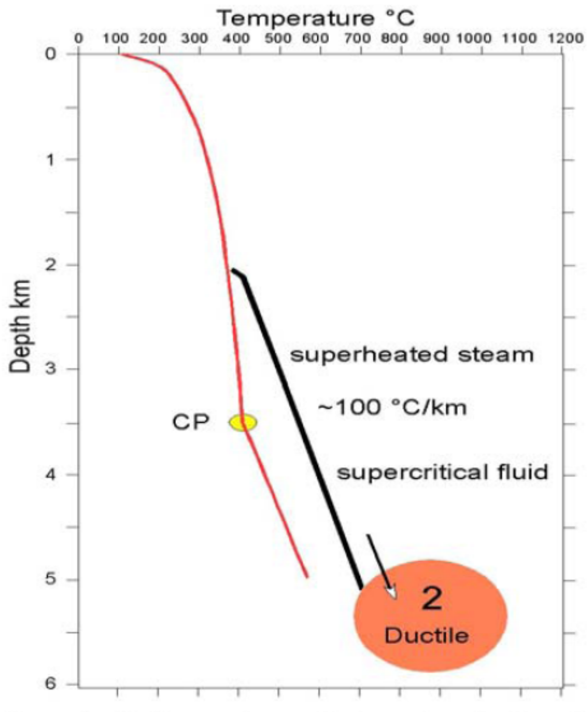

Fig. 15: Scenario: Drillhole penetrating the contact aureole to subvertical gabbro along the vertical margin of a cooling intrusion, involving upward flow of superheated steam derived from supercritical fluid (Fridleifsson et al. 2006).

In 2002 during the IDDP-ICDP workshop and in the IDDP Feasibility Report (Fridleifsson et al. 2003a,b), different P-T scenarios when drilling towards a cooling magma chamber within the Krafla geothermal field were discussed. It is recommended to test the margins of the cooling magma chamber for supercritical conditions, where the pressure and temperature condition should follow a path similar to that outlined in Figure 14 (a) (Fridleifsson et al., 2006). But also the case of drilling directly into the magma chamber should be considered, the hole would probably end in dry and ductile rocks, a scenario envisaged in Figure 14 (b).

Another possible scenario is illustrated in Figure 15 where the temperature-depth profile shows a borehole intersection with a permeable structure close to a heat source, penetrating the contact aureole of a subvertical gabbro intrusion. It involves upflow of superheated steam, which is a scenario probably like that at the NJ-11 well in Nesjavellir in 1985. The design of the IDDP drillhole should be capable of handling such conditions of superheated steam, with the anchor casing cemented to 2.4 km depth. The design of the well must handle superheated steam at pressures lower than the critical pressure at the wellhead to obtain samples for research and during eventual exploitation.

5.1.1 Underground Temperature Distribution

Temperature measurements on the surface and, if accessible, in drillholes are the most common means by which to determine the underground temperature distribution. The estimate of temperature distribution within a geothermal system is sought from the resistivity measurements on the surface. An underground temperature distribution for a cross section in the Krafla geothermal field is given in figure 16.

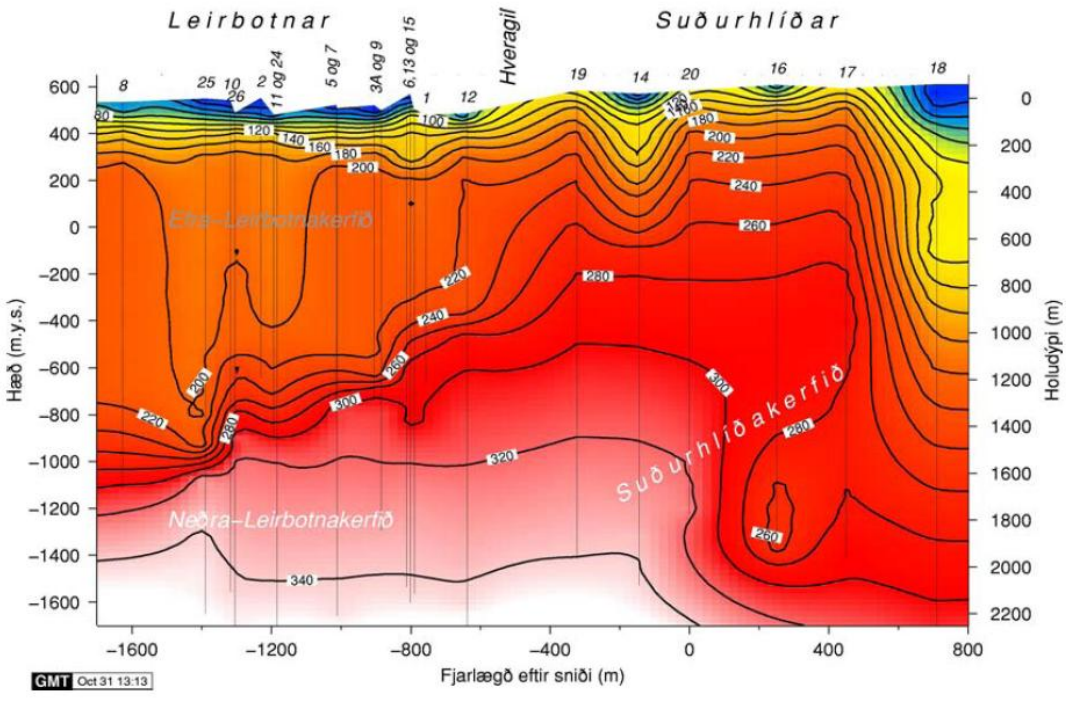

Fig. 16: NW-SE cross section showing the temperature distribution within the two main geothermal fields Leirbotnar and Sudurhildar in Krafla (Fridleifsson et al., 2006)

The IDDP-1 well is located north of the cross section shown in fig. 16. The temperature at 2400 m depth is expected to be around 350°C.

In different geophysical studies (Arnason & Magnusson, 2001 and Arnason et al., 2008) the resistivity pattern in the Krafla area roughly reflects the hydrothermal alteration pattern, e.g. the depth to the chlorite-epidote zone is reflected by a high resistivity core below a low resistivity cap at shallower depth.

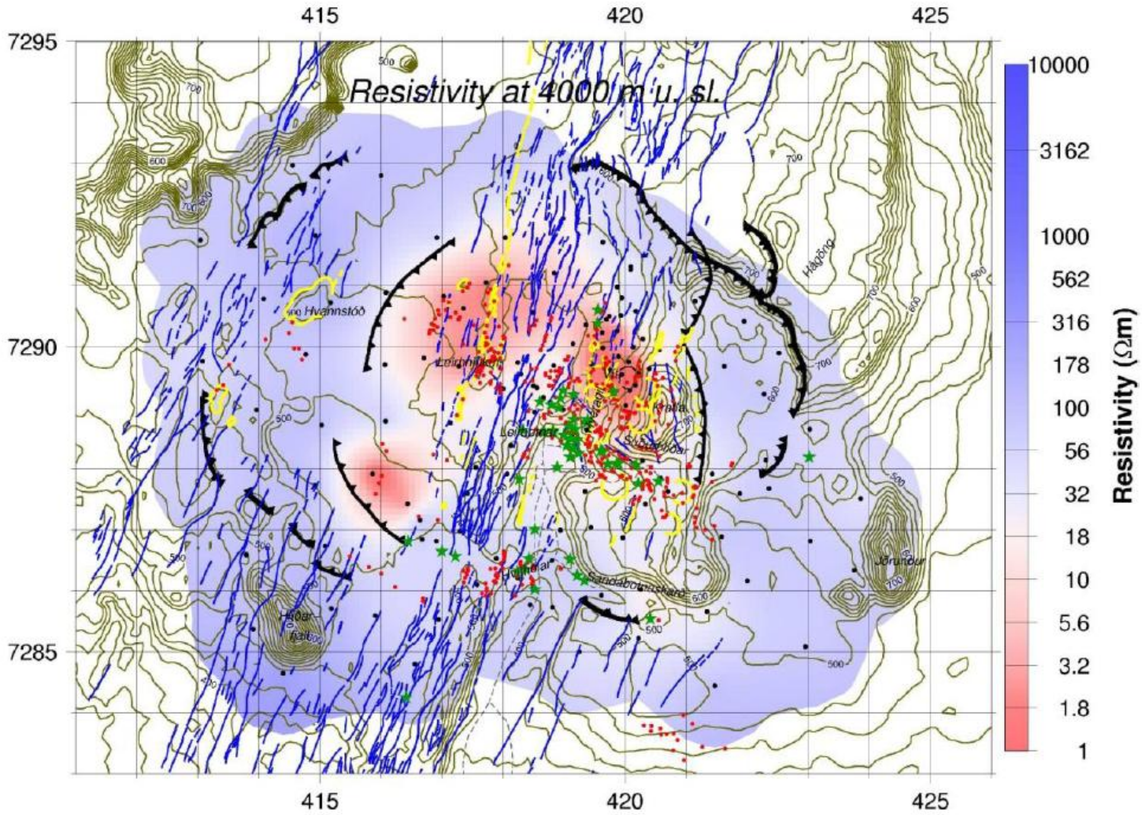

Fig. 17: Low resistivity at 4 km depth represented by red fields within the Krafla caldera; green stars represent the earthquake distribution (2004-2005) (Arnason et al., 2008).

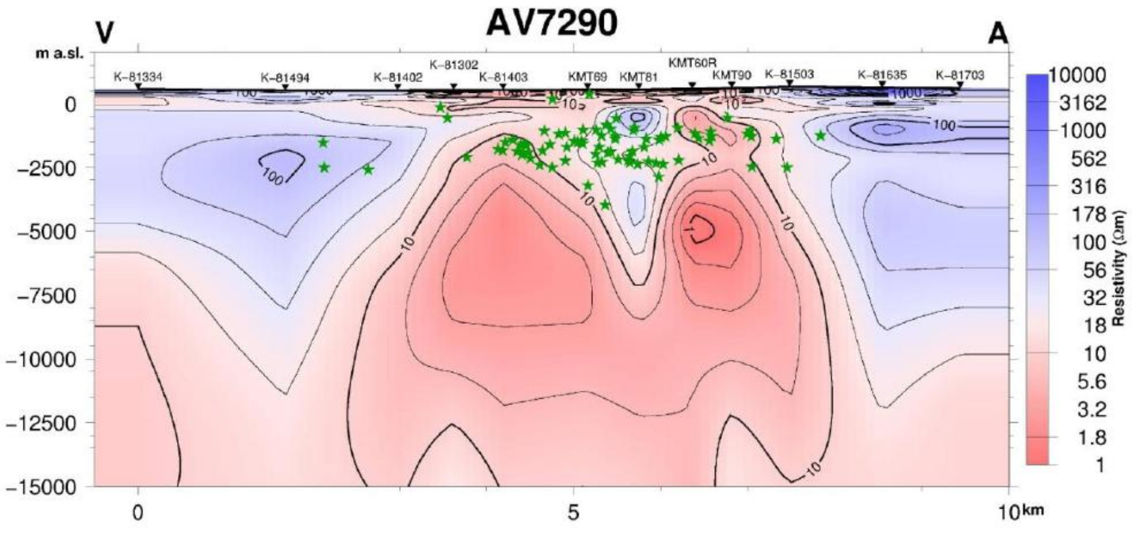

Fig. 18: W-E profile showing the shape of the deep low resistivity anomalies beneath the Krafla drill field and the depth distribution of seismic events recorded during 2004-2005 (Arnason et al., 2008).

The newest MT- and microseismic surveys confirmed the existence of a magma chamber, divided into western and eastern halves represented by the two deep, low resistivity anomalies doming up to the depth of about 2.5-3 km (red fields in figure 17), on both sides of the central rift zone.

An older MT-study from 2001 is stated below. The cross section overview map for orientation of the chosen profiles is given in fig. 19.

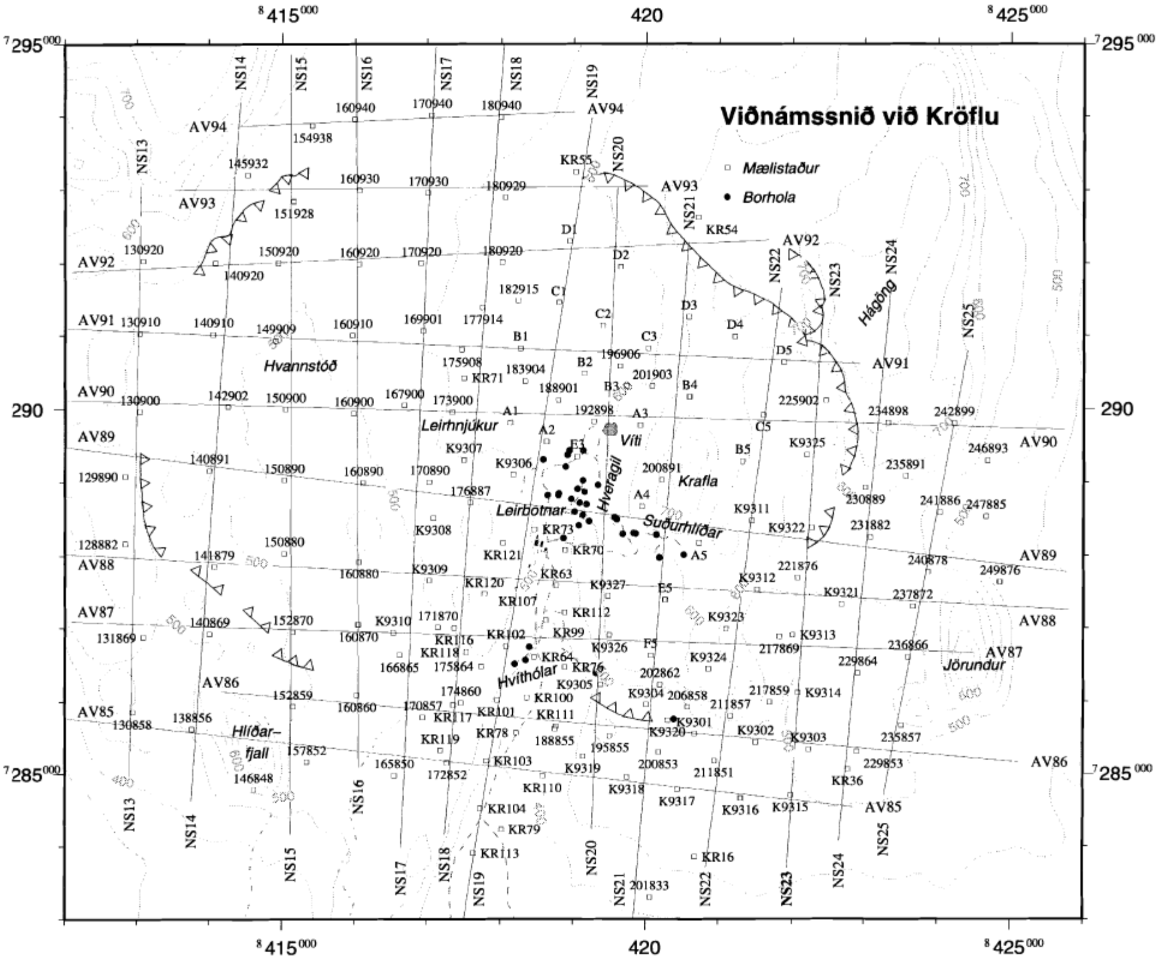

Fig.19: Cross section profiles of the TEM-study (Arnason & Magnusson, 2001)

The following profiles NS19 and AV90 are chosen to show the resistivity distribution in the close vicinity of borehole IDDP-1 down to depths of 1000 mbsl.

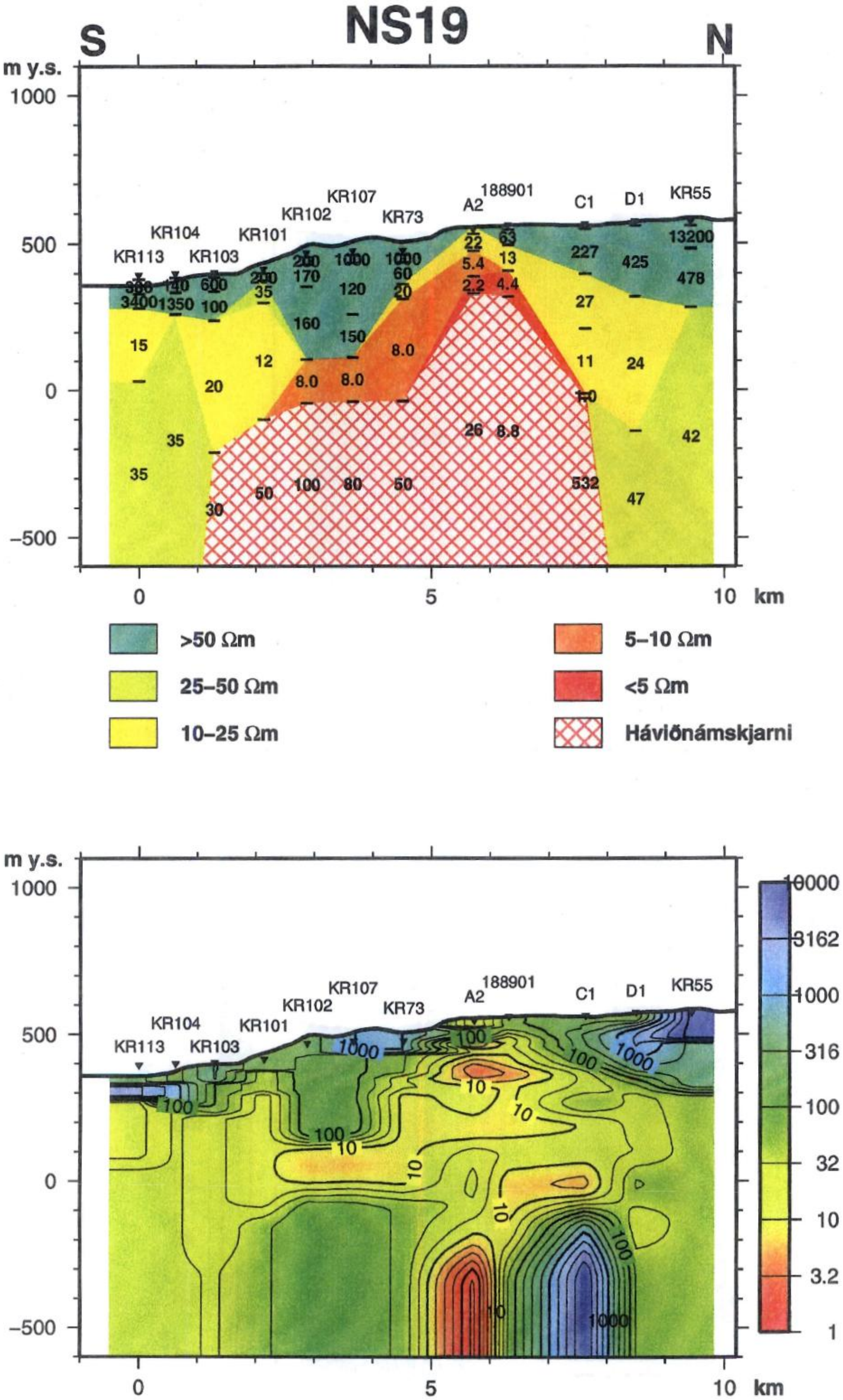

Fig. 20: Cross section NS19 (from Arnason & Magnusson, 2001)

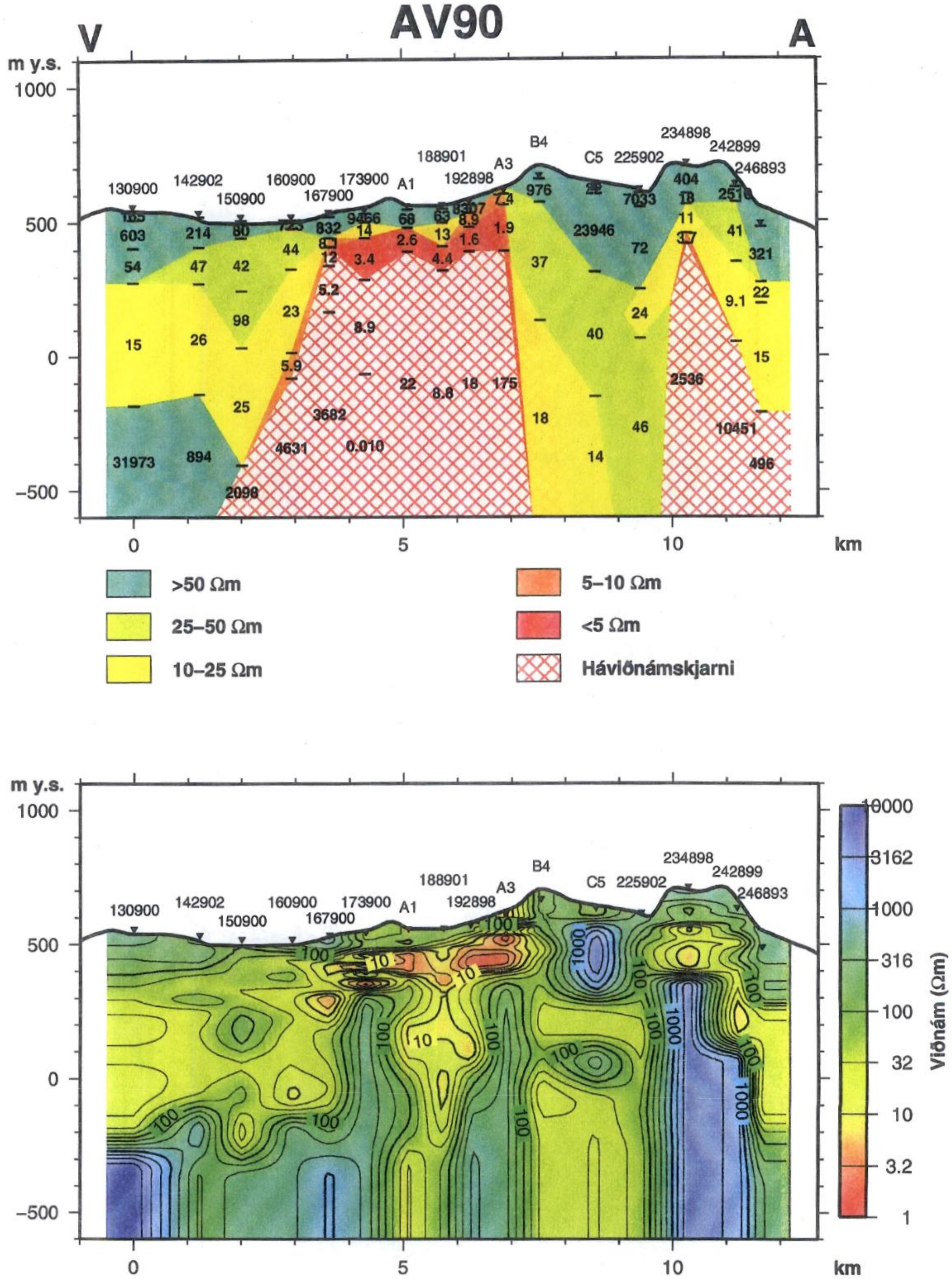

Fig. 21: Cross section AV90 (from Arnason & Magnusson, 2001)

The most important result of both MT-studies, with respect to the IDDP drill site and the Krafla drill field, is, that the MT-data supports the conclusion of the presence of a shallow level magma chamber below the Krafla drill field. However, the depth of a molten chamber cannot be determined exactly, as there is an uncertainty as to how the low resistivity in detail should be interpreted. But a partial melt and/or brittle/ductile boundary at subsolidus temperatures might result in lowering the resistivity at depths, and results of drilling just above the resistivity peaks closest to the Viti crater do not suggest that molten rocks exist just below the depths penetrated by drilling so far (Friedleifsson, 2008). The overall shape of the top of the low resistivity zone can be interpreted as an indicator of proximity to a magma chamber. In this respect a 5 km deep well at the IDDP-1 drill site would be in contact with the low resistivity surface as presented by Árnason et al. (2008). The boundary of recorded earthquake activity is another indicator for the partial melt or brittle/ductile zone at that depth. Therefore it can be assumed that temperatures in that depth range are around 600°C.

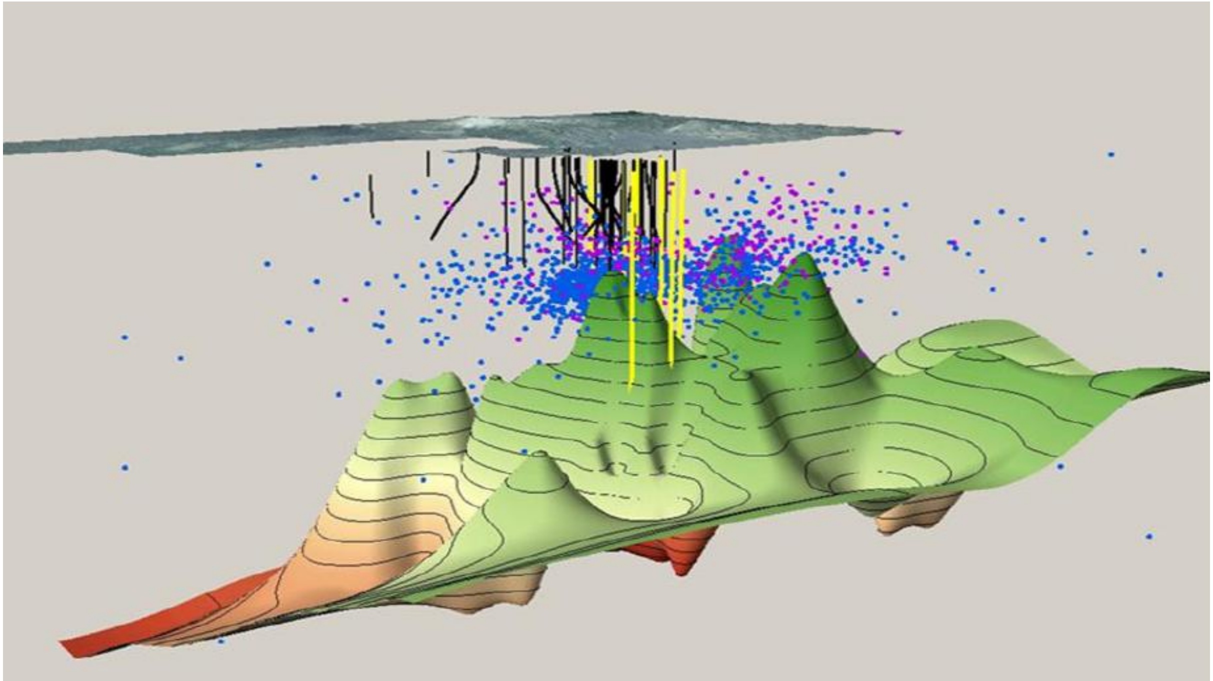

Fig. 22: Earthquakes recorded from 2004-2005 in violet and from 2006-2007 in blue, View from NE (Fridleifsson, 2008).

5.1.2 P-T Data from Wells in the Vicinity of the IDDP-1 Drill Site

Well KG-10, located on the plateau between Víti and Leirhnjúkur in Krafla, was drilled at 2082 m depth in the year 1976. The fluid showed a pH below 2 and appeared to be both corrosive and erosive. After a few weeks of discharging, the well was plugged with several types of scaling material. Since 1977 it has been used as monitoring well down to 800 m depth, there below is the top of the damaged liner (LVP, 2008a).

The following figures 23-31 show the pressure and temperature distribution in the Vitismor well field. All pressure logs show a constant increase in pressure with increasing depth- up to 160 bars at a depth of 2000 m in the well KG-25. The pressure in these stagnant wells increases with depth according to the hydrostatic pressure for the BPD condition and is fixed by the pressure of the most productive feed zone. When the well is induced to flow, the pressure profile changes due to the pressure drop caused by flow restrictions within the reservoir and also pressure drop in the well (Fridleifsson, 2003b). The loss of pressure in the wellbore for flow up the hole is mainly due to gravity but also due to friction and acceleration of the two-phase flow.

Temperature logs show the 300°C temperature border at different depths. In well KG-2 this mark is not reached, but the well ends at 1200 m with a temperature around 220°C. Well KG-4 already exceeds the 300°C at a depth of app. 700 m in one measurement. However, well KG-8 reaches this temperature level at around 1600 m, which has been proven in several measurements. Before well KG-10 was sealed at 800 m, one deep measurement showed a temperature exceeding 300°C at approximately 1400 m. In well KG-25 300°C is reached at 1400 m in some measurements in 1991 and then again at a deeper depth of 2070 m at different times during the 1990 till 1996 measurement campaign.

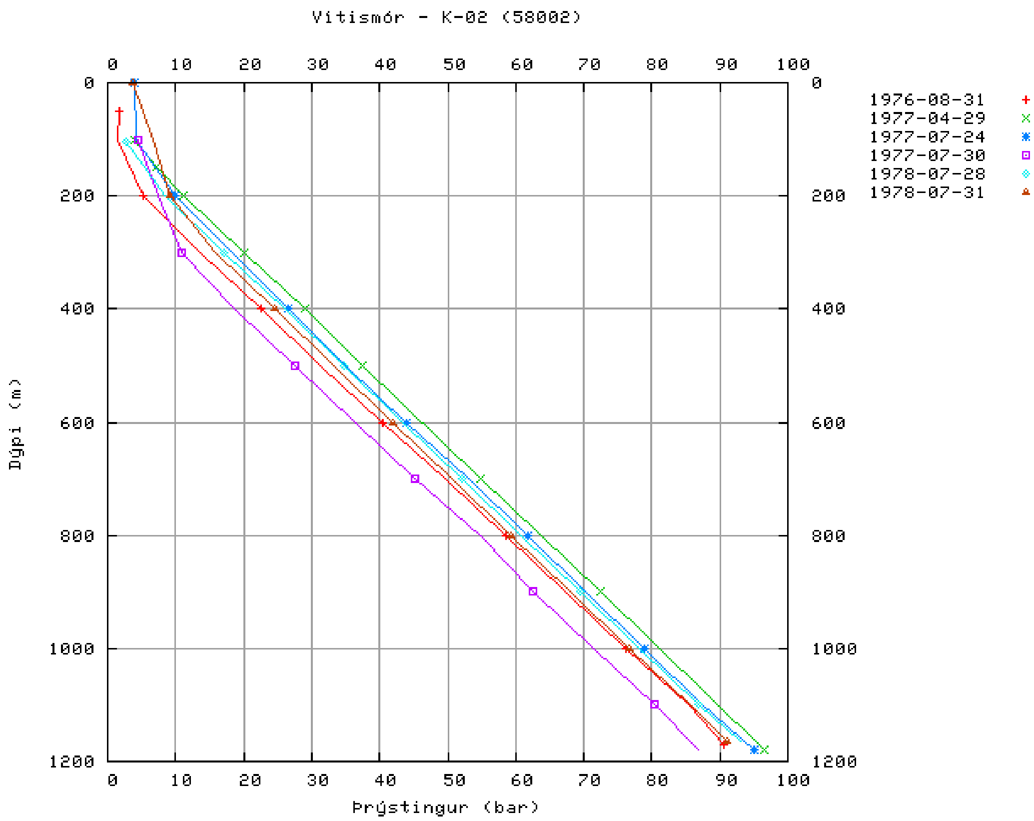

Fig. 23: Pressure logs in well KG-02 in 1976 - 1978 (ISOR, 2008c).

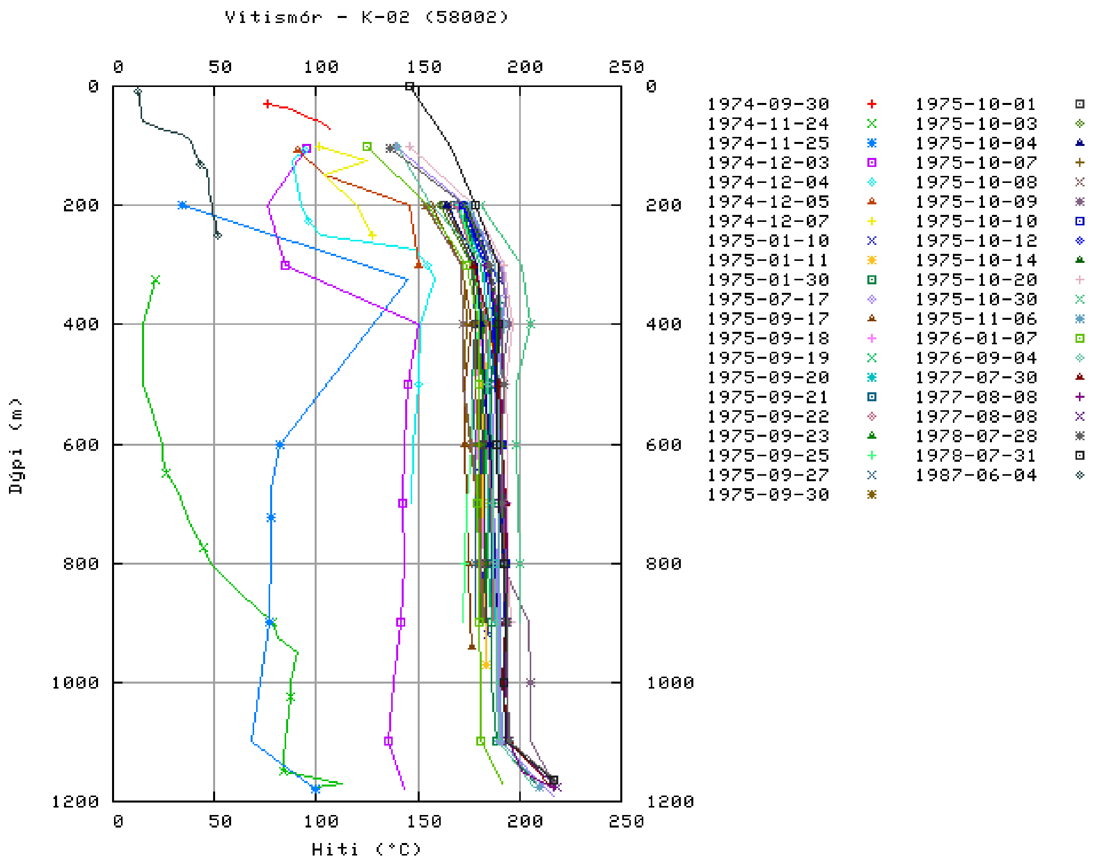

Fig. 24: Temperature logs in well KG-02 in 1974 - 1987 (ISOR, 2008d).

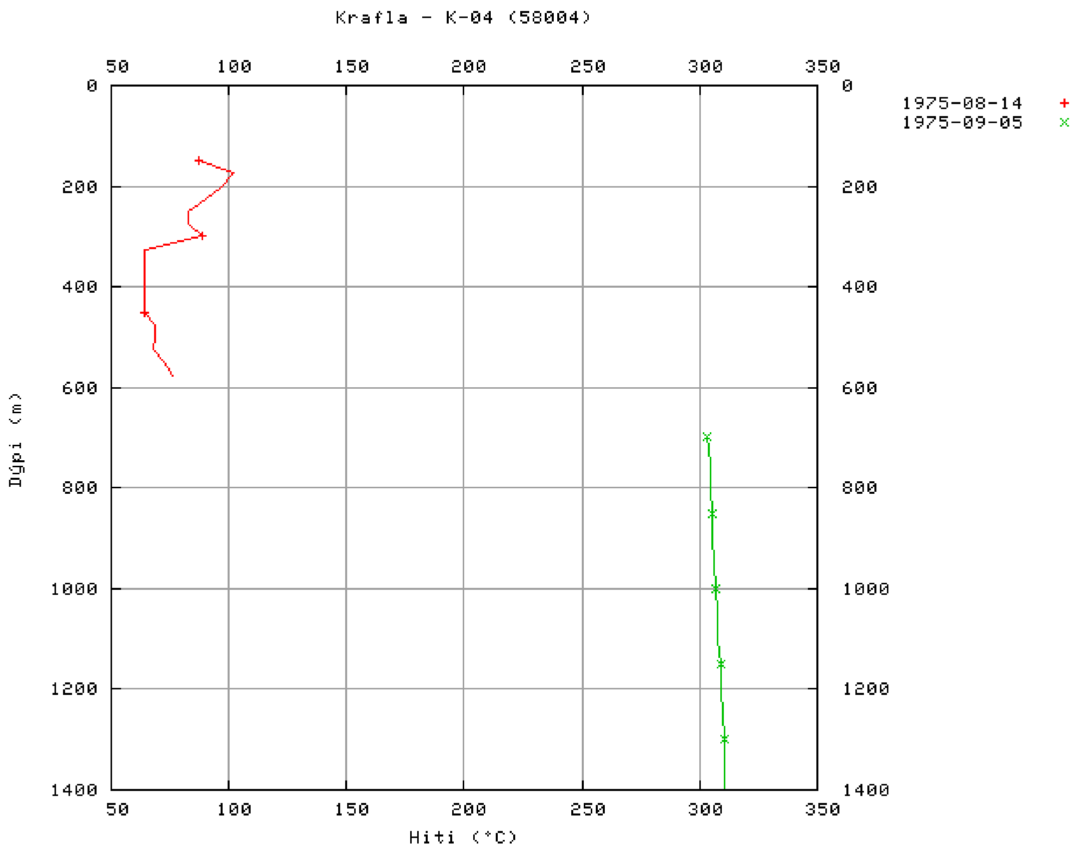

Fig. 25: Temperature logs in well KG-04 in 1975 (ISOR, 2008e)

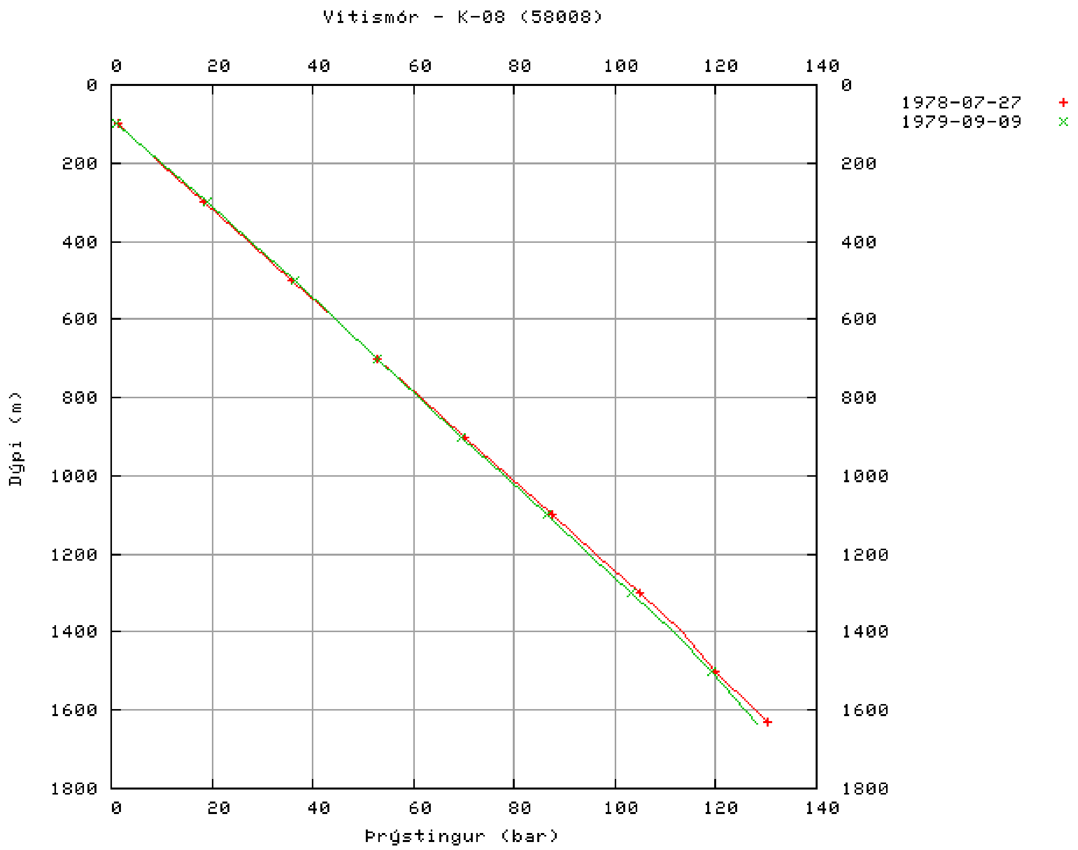

Fig. 26: Pressure logs in well KG-08 in 1978 - 1979 (ISOR, 2008f)

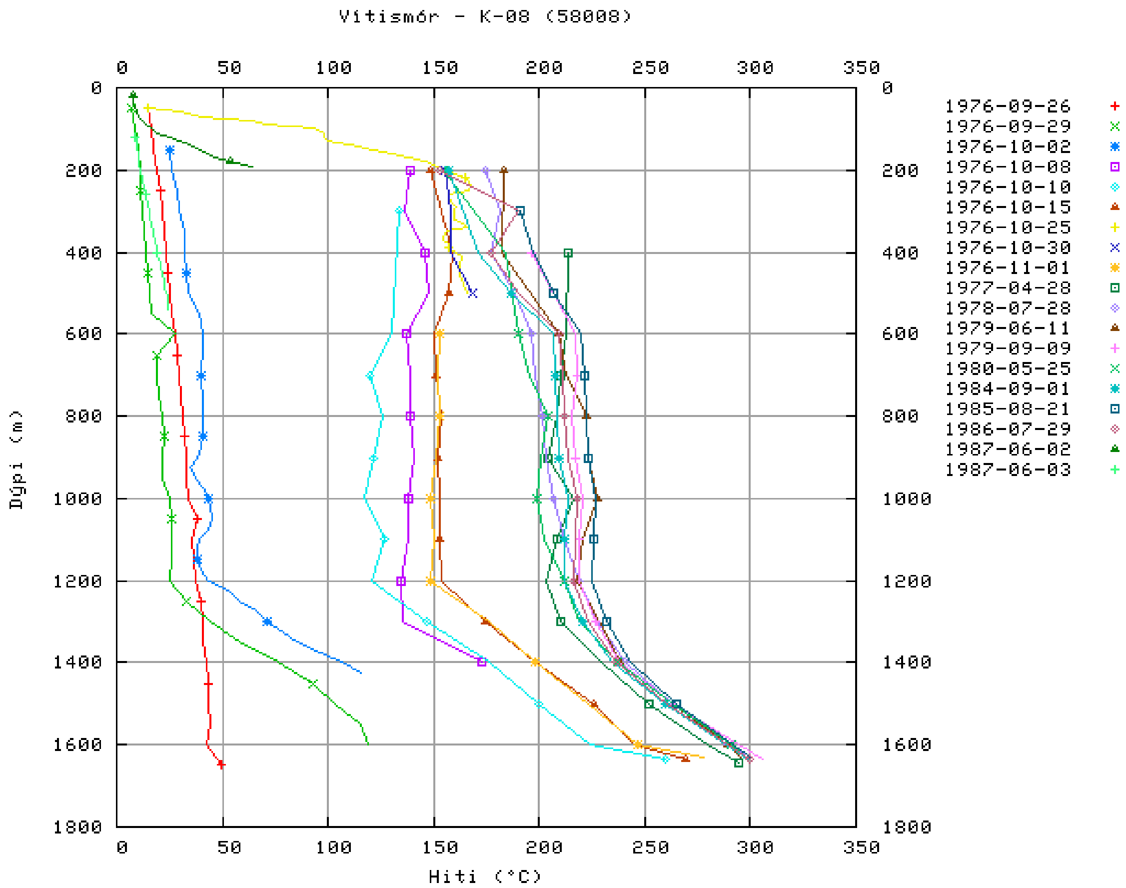

Fig. 27: Temperature logs in well KG-08 in 1976 - 1987 (ISOR, 2008g)

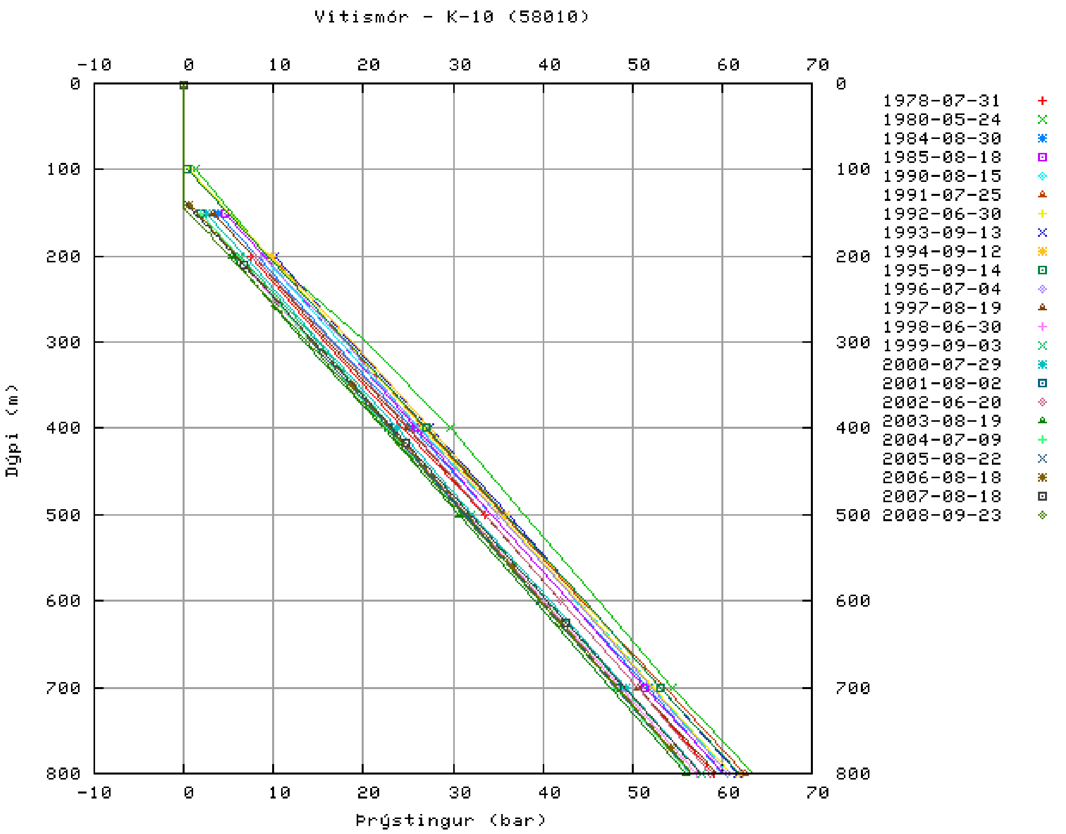

Fig. 28: Pressure logs in well KG-10 in 1978 - 2008 (ISOR, 2008h)

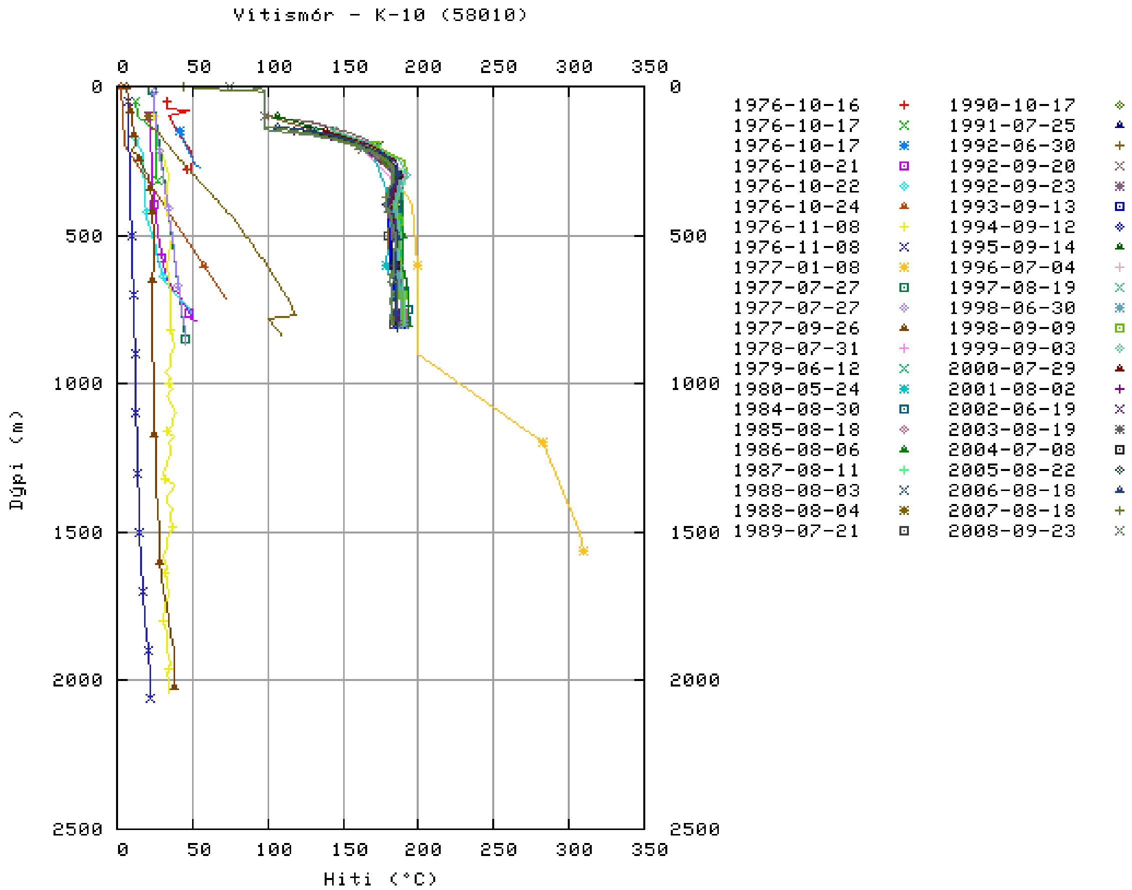

Fig. 29: Temperature logs in well KG-10 in 1976 - 2008 (ISOR, 2008i)

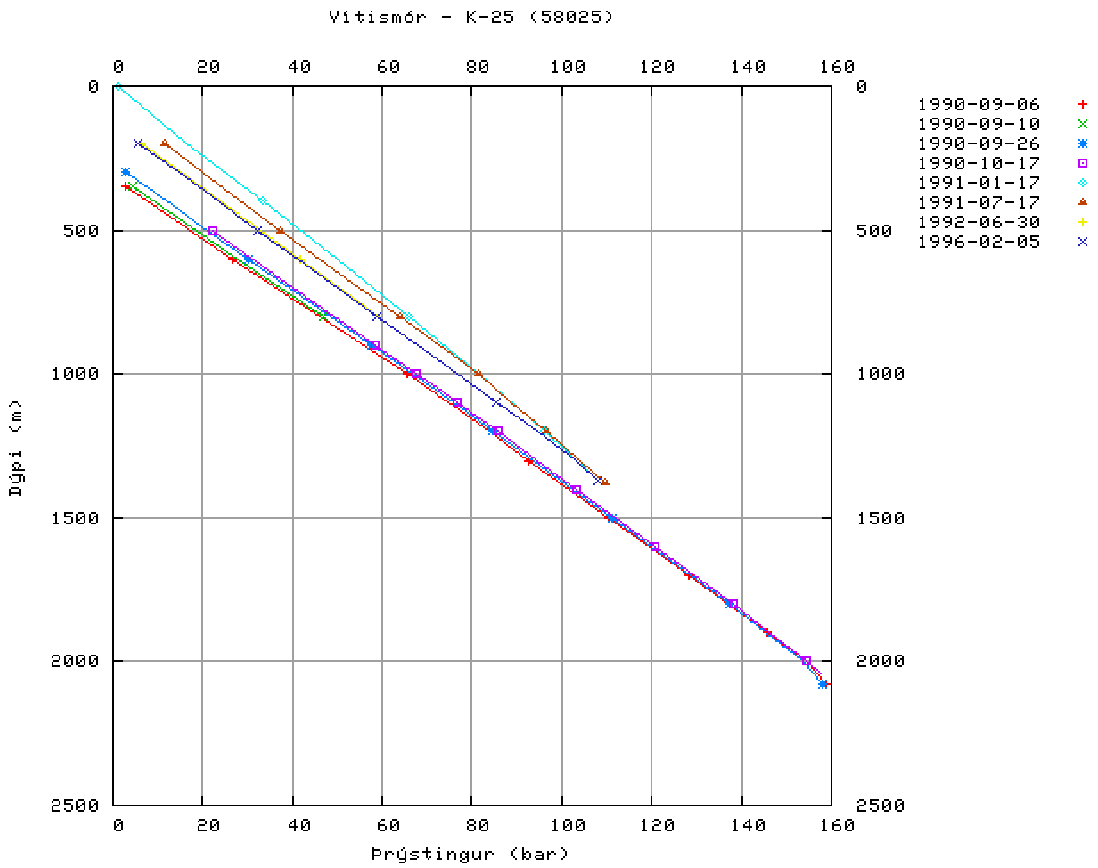

Fig. 30: Pressure logs in well KG-25 in 1990 - 1996 (ISOR, 2008j)

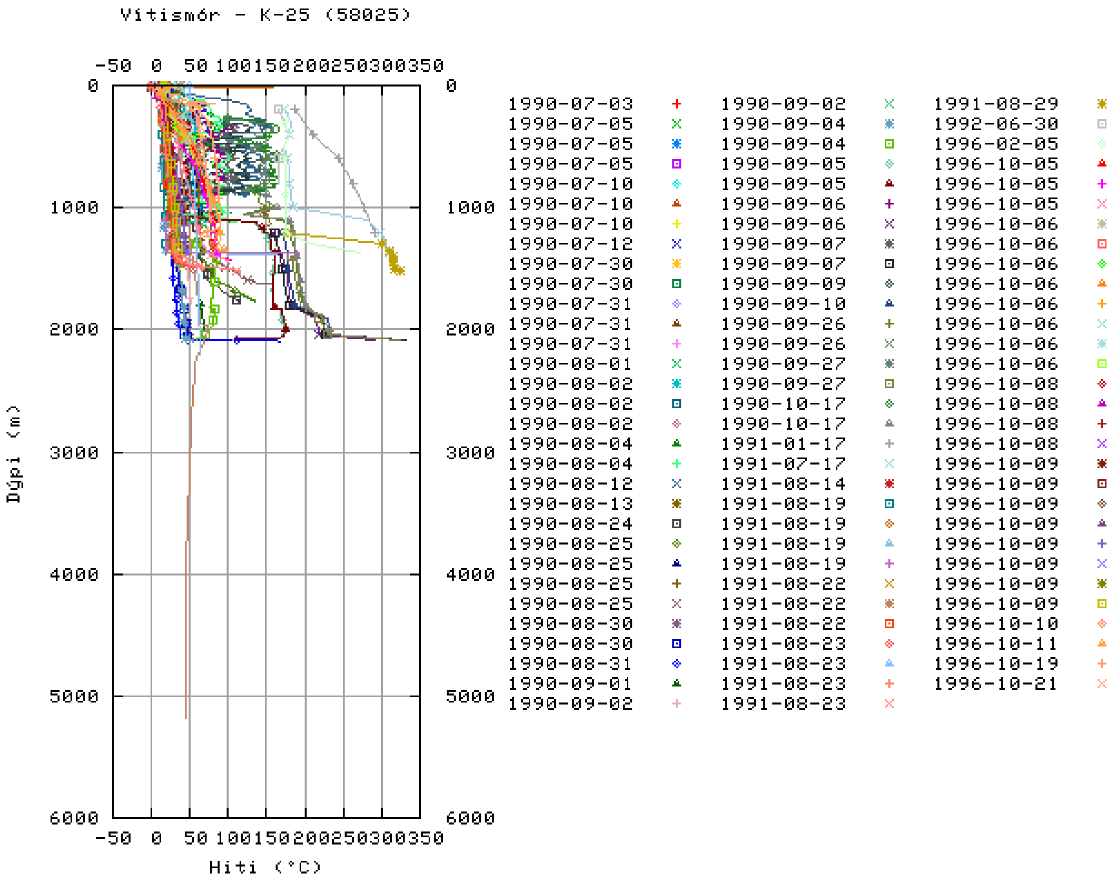

Fig. 31: Temperature logs in well KG-25 in 1990-1996 (ISOR, 2008k)

According to these measurements it can be inferred that the critical temperature (374.15°C) and pressure (221.2 bar) zone in the IDDP-1 well can already be reached at a depth between 2600 - 3500 m, depending on the dissolved chemical components in the geofluid. It is highly likely that under these high temperature and pressure conditions the share of dissolved minerals in the geofluid is high, which can elevate the critical point to higher temperatures and pressures, so that the critical zone is expected to be deeper than 3500 m. But the first scenario should be considered in terms of well design and safety measures for the drilling process.

5.1.3 Temperature Limitations and counteractive Measures

Due to the extremely high formation temperature expected at the bottom of the well a continuous temperature profile of the undisturbed natural temperature cannot be obtained with existing measurement tools. But by simplifying the various fragmentary data it should be possible to reconstruct a temperature profile. The temperature profile at depths from near surface to the critical point is obviously expected to show a boiling point controlled curve, whereas the profile from the CP down to the bottom of the well is expected to be a conduction controlled curve with a very high gradient. This combination is also supported by the hypothesis of a magma-ambient environment discussed by Fournier (1987).

Temperature Measurements

To actually measure the temperature down hole, temperature melting tablets were used in the WD-1 well in Kakkonda, Japan, to confirm the high temperature region, which could not be measured by available PTS and Kuster tools. The tablets for measurements had twelve different melting points at temperatures ranging from 399 to 550°C. The tablets were made of various inorganic compounds such as chromium, molybdenum, tungsten, barium, sodium and potassium. Each tablet was packed in a stainless steel container and installed in a steel vessel that was held at the bottom of the well for one hour using a stainless steel wireline (Muraoka et al, 1998). After removing the tablets from the borehole, the different tablets were checked to see whether they had melted or not in order to infer approximate bottom hole temperatures.

But other solutions for temperature measurements up to 550°C are available. The accuracy, ease and cost of making temperature measurements in high temperature geothermal wells have undergone significant improvements over the past two decades. Wisian et al. (1998) provides a succinct summary of the temperature logging tools currently in use: namely, the slick-line computer tools and the Distributed optical-fiber Temperature Sensing (DTS) system. The slick-line tools employ a self-contained, battery-powered computer and temperature sensor housed in a Dewar flask assembly, which is lowered into the well on a solid wire. The Dewar flask protects the sensor under high-temperature environments inside the well and has been tested up to temperatures of 400°C continuously for about 10 h. Another solution, the DTS tool, developed by Hurtig et al. (1994), has the potential of withstanding well temperatures of up to 550°C. The tool works using Raman Effect backscattered laser light in an optical fiber. Observations of the intensity of backscattered light with time can be used for determining the temperature along the entire length of the optical-fiber cable instantaneously. Although this tool is less accurate in temperature and depth by an order of magnitude relative to the electric-line and computer-based slick-line tools, it can be gainfully employed to monitor transient events in a well by keeping the entire cable lowered inside the well for several days without perturbing the water column due to repeated lowering and raising of the tool (Gupta & Roy, 2007).

Drill Bit

One of the most important functions of the drilling fluid is to cool the bit and well. The temperature downhole influences bit life and dictates what downhole tools can be used. Tools such as mud motors, drilling jars, logging tools and measuring-while-drilling devices (MWD) can be deployed. Most commonly used in geothermal drilling are roller cone bits with hardened-steel teeth or tungsten-carbide inserts. Since the steel used in roller cone bits is drawn at temperatures 200–250°C, these bits lose much of their strength when operated at temperatures in excess of 250°C (Gupta & Roy, 2007). This causes rapid failure of bearings and steel teeth as well as loss of inserts with the insert bits. Expensive roller cone bits are provided with sealed lubrication systems, which have rotating rubber seals to hold the grease in the bearings. But these rubber seals also have a temperature limitation of about 200°C. Improved seals and improved high-temperature lubricants are required in high-temperature geothermal drilling. Diamond drills can drill at temperatures in excess of 500°C. However, since their drilling rate is much slower compared to roller cone bits, they do not provide a very acceptable solution to the problem of high-temperature drilling. Three-cone bits have temperature sensitive parts such as O-ring seals and diaphragms, which are prone to damage during drilling in high temperature geothermal wells. O-ring seals never survived more than 29 hours of rotating time in other wells where the formation temperature is over 350°C (Saito, 1996). Other temperature sensitive parts are the stator of the mud motors and the electrical components in the logging tools. As long as the mud or water circulation is maintained, it is even possible with conventional geothermal drilling methods to keep the downhole temperature below 100°C.

Counteractive Measures

The following described procedures, techniques and equipment can be used to overcome the temperature limitations of current drilling technology. The key factor hereby is to cool the borehole and the downhole drilling tools at all times of operation.

To avoid mud gelation in the high temperature borehole very thin high temperature drilling mud can be used, even though this compromises the cuttings-cleaning efficiency. This mud consists of 3% bentonite, 0.1% high temperature dispersant, 1% lubricant, and caustic soda. The specific gravity yield value and plastic viscosity of the mud is then in between 1.1 to 3 lb/100ft^2 and 4 cP, respectively. Conventional mud coolers can be used to cool the return mud.

A variety of commercially available high temperature downhole tools like rated positive displacement motors and retrievable-type measurement-while-drilling tools, which are partly still under development (Hiti-Project) can be applied. Those tools can be set by wireline after the well has been cooled by circulating the mud at the bottom of the well (Coe & Saito, 1994).

The harshest environment for the bottomhole assembly (BHA) is when it is run in the wellbore, since the borehole temperature increases while BHA round trips are made. In order to cool the BHA and the well while running it in the hole, the BHA running operation can be interrupted as long as mud is circulating (Saito et al., 1998).

The borehole temperature is an important parameter in relation to the drill tools and the maximum temperature ratings of the drilling mud. The following methods were used to estimate the well temperature in the WD-1 well in Kakkonda, Japan, and can be applied as well to the IDDP-1 well: Mud temperature monitoring in and out of the hole; Thermometers can be installed on top of survey tools so that borehole temperatures can be monitored at less than one hour recovery time; Measurement-while-drilling (MWD) temperature surveys; mud-circulation temperatures in the hole can be monitored when the MWD tool is used for drilling. Tests showed that temperatures inside and outside the tool equalized within a few minutes (Saito, et al., 1998).

Tab. 5: Temperature limitations for drilling tools and associated materials, based on manufacturer data, not field data (Saito et al., 1998)

Tools / Materials	***Temperature Limitations [°C]***
Downhole Motor Stator Rubbers	
Now	150-175
Under Development	175-200
Seal Materials	
O-Ring & Diaphragm	150-190
Trajectory Measurement Devices	
Retrievable MWD	150
Non-Retrievable MWD	175
Mud Dispersant	250-300
Explosives	
Backoff	220
Perforation	150

Experiments in the exploration well WD-1 in Kakkonda, Japan, showed that a geothermal well can be drilled even where the formation temperature is as high as 500°C, provided the well is properly cooled and conditioned to permit drilling with conventional methods. But it becomes very complex to continue drilling operations in the presence of multiple difficulties such as high temperatures and gas ejection. The key to overcoming the high temperature environment is the mud cooling system, which cools the return mud and a top drive system, which in turn cools the bottom hole assembly continuously while running every drillpipe stand into the hole. With these cooling methods, available positive displacement motor and measurement-while-drilling tools could survive in such a high temperature environment even where the undisturbed formation temperature is over 250°C. Furthermore the O-ring seals of the three-cone bits could survive for more than 60 rotating hours and could drill more than a 100 m section, even where the static formation temperature was over 350°C. So the cooling depends highly on the rate of circulation (l/s), the borehole diameter and whether there are loss zones. This is especially important in terms of coring (see chapter 5.4).

5.1.4 Formation Fracturing

On the other hand, due to formation cooling and too high a fluid column, formation fracturing can occur. This can lead to undesirable hydraulic connections and circulation loss, or even wellbore failure. To avoid such a situation, fracture tests should be performed.

In case of the occurrence of undesired fracturing and severe losses of circulation, cementing a plug section and re-drilling can be a solution.

Because of the high density of the designed cement slurry, which is 1.9 kg/l, an increased risk of formation fracturing is acceptable

5.1.5 Risk Probability

By reaching depths with temperatures above 300°C the probability of temperature related effects on material and well control becomes quite likely. That is why the probability of material failures including the drill bit, mud motors and drill string assessed to 65-75%. In terms of temperature effects on logging tools the risk is assessed to 40%. The reduced risk in terms of logging devices can be explained by the newest developments in the insulation of these devices and developed procedures as they are stated above. The risk of fracturing the formation due to cooling effects is assessed to 50% due to the fact that basaltic rocks in general are more resistant to thermal stress than metals. In terms of formation fracturing caused by high fluid column and/or mud pressure the probability is expected to be 60%.

5.1.6 Impact on Drilling Process

The impact of high temperatures and pressures on the drilling process will primarily result in poor bit performance and therefore in low penetration rates, which will delay the whole drilling operation, which again will result in an increase of the drilling costs. The high temperature environment is also problematic for the drill string and casing material whether in alleviated form or not. The Icelandic drilling crews have some experience with high temperature wells up to 380°C, but temperatures above this level have not been experienced in active drilling processes. Based on the local expertise and the experience from the high temperature well in Kakkanoda, Japan, a risk in material failure cannot be excluded and is quite likely in the very high temperature environment at the end of the planned borehole. Thus the impact factor is assessed to 3, if mitigation and action measures cannot be applied or fail. Mitigation measures like alternative material selection for drilling equipment and cooling procedures are described above.

5.2 Underground Pressure Blowout

There is always the risk of a blowout while drilling a in a geothermal field. A blowout may occur when an unexpected, high-pressure permeable zone is encountered. An underground pressure blowout can be defined as an uncontrolled flow of geofluids from an underground reservoir through the wellbore and into the atmosphere or another underground formation. Deep wells with high temperature and high pressure, drill locations in volcanic active areas, and geofluids in supercritical phase are some of the challenges that characterize the first IDDP well in Krafla. All of these aspects are associated with an increasing blowout risk.

During all phases of drilling, an uncontrolled wellbore influx of formation fluid from a permeable zone (kick) indicates that the well is unstable, and constitutes the first phase in a sequence of events that may lead to a blowout. Obviously, kick prevention is the primary objective for well control while the secondary objective is early kick detection. Whether a kick develops into a blowout depends on how early the kick is detected, the downhole conditions, available kick tolerance, equipment reliability, and the degree of success in choosing and applying a method to remove the influx from the wellbore and re-establish pressure balance (kill procedure) (Andersen, 1998).

5.2.1 Mitigation Measures

Therefore the use of blowout preventers is standard practice nowadays. These are a set of fast-acting valves attached to the casing being drilled through. In the event of a “kick” from the well, these valves are slammed tight around the drill string, effectively closing off the well. Another valve attached to the wellhead just above the casing allows for controlled venting of the well to a silencer until the well is brought under control, usually by quenching the well with cold water (DiPippo, 2008).

The first steps towards blowout control have to be established in the planning phase of a new exploratory well. Well known deterministic coherences and drilling experience form the basis for the development of drilling procedures, casing programs and mud programs. The actual value of the most important parameters included in the well planning process is, however, uncertain, e.g. pore pressure and formation strength. Thus, the potential to manage the parameters that are decisive to the outcome of the drilling operation depends on good predictions in the well planning phase and the ability to organise personnel, to establish procedures and equip the drilling rig.

A study of these deterministic coherences reveals causal mechanisms of the kick process, the significance of the parameters involved, and dependencies between these parameters. A good example of an important deterministic coherence that controls the wellbore influx rate is given by the line source solution of the radial diffusivity equation for a homogeneous, gas saturated infinite reservoir, e.g. (Dake, 1978):

$$q_g = \frac{1.77 \cdot 10^{-2}\; h\; k\; \left(P_p^2 - BHP^2\right)}{\mu_g\; Z\; T\; ln\left[\frac{4kt}{1.02\gamma \Phi \mu c r_w^2}\right]} \qquad [3]$$

q_g = gas flow rate from reservoir (kg/s)	T = temperature (K)
c = compressibility (Pa $^{-1}$)	μ_g = viscosity (kg/ms)
P_p = pore pressure (Pa)	Φ= porosity
r_w = wellbore radius (m)	h = reservoir height (m)
k = permeability (m^2)	z = gas factor
BHP = bottom hole pressure (Pa)	γ = Euler constant
t = time (s)	

From this equation [3] we can see that most of the parameters that affect the gas kick flow rate are fixed by nature, i.e. permeability (k), porosity (Φ), pore pressure (P_p), formation temperature (T) and the flow medium parameters (μ_g, q_g, c, z). Hence, the planning or drilling company's influence regarding kick prevention is limited to the following measures:

- Pre-drilling predictions of the naturally fixed parameters that constitute the basis for the subsequent well planning.
- In situ measurements of the naturally fixed parameters followed by appropriate adjustments of the wellbore bottom hole pressure (BHP).

A gas kick occurs when the parameter values in eqn. [3] give $q_g \geq 0$. Thus, an approach to monitor the kick probability is to assess probability distributions directly to specific values of the parameters in [3]. In order to avoid wellbore problems like influx, collapse, stuck pipe, mud losses, etc. the drilling crew seeks to maintain a proper downhole differential pressure. During drilling, however, the downhole differential pressure may vary significantly because of unpredictable fluctuations in the formation pressures and difficulties related to measuring and interpreting the wellbore feedback. The dynamic changes of the differential pressure can be interpreted as the bottomhole pressure (BHP) is travelling between different states, e.g. underbalance, degrees of overbalance, and fracturing. Because of that the differential pressure in the well (BHP, P_p) is important to monitor so that through the BHP reading, measures to prevent a kick can be initiated.

Considering a circulating suboperation, we find that the hydrostatic head's contribution to the total BHP is mainly dependent on the drilling fluid density and the height of the mud column, whilst pump force and well design significantly affect the frictional pressure loss. Thus, important causal mechanisms related to an unintentional significant reduction in BHP during a circulating operation are given as follows (Baker Hughes, 1995):

- Low wellbore mud volume caused by major mud losses to the formation, fracturing, failure in isolating loss zones, mud refill failure, major mud losses to the external environment,
- Unintentional decreasing mud density caused by temperature effects, gas cut mud, wrong density readings, failure in density measurement equipment, operator failure to refill correct volume weight material, calculation failure, communication error,
- Decreasing annular frictional pressure losses caused by pump failure, power failure, pump control failure, operator failure, communication error.

To avoid such problems we have to ensure and control the drilling process by considering the standard company specific drilling procedures, the drilling program, and equipment systems. In a high temperature environment like the desired target area of well IDDP-1 it is vital to the whole project that the drilling fluid is cooled at all times during drilling and well completion. In terms of making serious predictions in possible hazard zones, we have to answer following questions: Is the kick detection system good enough? Is complex regional geology and pore pressure regime critical in the sense of causing poor prediction of pore pressure, formation strength and pressure margin? Is the company‘s specific drilling philosophy regarding, e.g. near balanced drilling critical? Due to the lack of experience with supercritical fluids and the limitations of the available data one could only make more general conclusions and therefore it is recommended to be prepared for the worst case. That means, in particular, having backup cooling systems, replacement equipment, and an additional blowout preventer (BOP) on the drill site to be able to act quickly in case of emergency.

5.2.2 Counteractive Measures

Consecutively two counteractive measures for dealing with an underground pressure blowout are described. A common cause for blowouts is the fracturing of formations below the casing shoe by excessive annular pressures. If the flow is not too severe, it may be possible to pump LCM in a light fluid, or a "gunk squeeze" down the annulus while killing the high pressure zone down the drillpipe with heavy mud. The direction of fluid flow is an important concern when choosing a control procedure. The cause of the blowout will often indicate the direction of flow. Assuming that shallow zones are more likely to fracture than deeper zones, and that the initial kick zone is the primary source of formation fluid, the direction of fluid flow will generally be upward. In the case that a zone of lost circulation is encountered at the bit, the flow may be from a shallower zone to a deeper zone. The loss of hydrostatic head may induce an upper zone to kick, while the flow will generally be to the zone of lost returns.

Methods of killing an underground blowout are (Baker Hughes, 1995):

„Running Kill Method":

1. As soon as the symptoms are recognized

    a. Request or rig up a logging unit for a temperature log and noise log

    b. Start increasing the mud density in the pits

    c. Kill the drill pipe side with the heavy mud

    d. Continue to pump a few barrels of mud every 30 minutes to keep the bit from plugging

    e. If the drillpipe sticks, pull and stretch the pipe to prevent buckling above the free point.

2. Rig up the wireline logging unit and run the temperature log going down the drillpipe and the noise log while pulling out.

    a. Determine the point of fluid entry and fluid exit

    b. Calculate the mud density required to kill the well between the point of entry and the point of exit. The calculated mud density may exceed 20 ppg. In this case, use the highest mud density that can be mixed and pumped.

3. Mix a minimum of 3 times the hole volume of either the required mud density or the maximum pumpable density. Simultaneously

    a. Ensure pumps are in good condition

    b. Obtain high volume mixing equipment

    c. Blow the jets out of the bit and/or perforate above the bit to maximize the flow through the drill string

4. Pump the mud at a high rate until all the mud has been pumped. Do not stop until 3 times the estimated hole volume of heavy mud has been pumped.

5. Run the temperature/noise logs to determine if the well is dead. If it is dead, bleed off any casing pressure and rerun the logs.

Even though the pumped mud will be cut, the annular density will increase as more mud is pumped. As the annular density increases, so will the back pressure on the formation, resulting in a decreased kick flow rate. In case of a much heavier mud and fast, continuous pumping a kill can be accomplished with a limited volume of mud, but cannot be accomplished if the mud weight is only 1 to 2 ppg heavier than the estimated bottomhole pressure (Baker Hughes, 1995).

Bullheading Method:

This is defined as pumping fluid into the well without circulation back to the surface. The fluid can be pumped down the drillpipe, down the annulus, or both. Wells with short open hole sections and zones of high permeability respond better to bullheading than wells with long open hole sections and low permeability zones.

The quicker the flow can be reversed, the less amount of drilling fluid has to be pumped to force the influx back into the formation. Any gas in the kick will migrate up the hole at a rate dependent upon the drilling fluid's density and viscosity. There are no specific rates at which bullheading should be performed. At slow rates (the pressures are within the boundaries of casing burst pressure) the pump rate can be increased until the higher pressure will become detrimental to the operation. The higher pump rates are desirable to pump the influx away as soon as possible, and to overcome any gas migration. Once the influx has been pumped away, normal circulation should be resumed to establish a balanced fluid column. The circulation of kill fluid should be at a rate that does not break down the formation any further. In areas where H_2S is present as a possible kick component, bullheading provides a useful means of limiting the amount of gas that has to be dealt with at the surface.

Advantages of Bullheading:

1. Prevents Hydrogen Sulfide from reaching the surface
2. Keeps formation gas away from rig floor
3. Lower surface pressures are commonly used
4. Useful when underground blowouts occur
5. Can be used with or without pipe in the hole
6. Can be used to kill liner-top leaks

Disadvantages of Bullheading:

1. Fractures formations
2. Can burst the casing
3. May break liner top
4. Can plug drillpipe

5. Will lose mud to formations (may therefore be expensive)
6. May pressure up formations, causing a back-flow when circulation is stopped

In case these efforts should fail, the drill pipe can be cut with the shear rams and the drill string allowed to fall to the bottom, and at the same time close the well. By having the tool joint in the proper place the drill string can be held by the pipe rams, preventing the string to fall to bottom (Fridleifsson et al., 2003b) It should be noted that all operations, such as cutting the drill pipe or pumping cement into the hole for a permanent seal are examples of last resorts.

Another risk beside blowout should be mentioned here because it is also a matter of uncontrolled outflow from the well, here especially the wellhead. In a volcanic area like Krafla, the presence of toxic gases such as hydrogen sulphide (H_2S) can be expected and lead possibly to severe injuries and even fatalities. The cellar of a wellhead is a particularly dangerous place since both H_2S and carbon dioxide (CO_2) are heavier than air. If there are any leaks from the well or casing these gases can accumulate in the cellar. Therefore H_2S and CO_2 sensors should be installed.

5.2.3 Risk Probability

The risk of having an underground pressure blowout is dramatically increased in a very high pressure and temperature environment like it is in the target area of the IDDP-1 well. The probability is therefore assessed to 90%.

5.2.4 Impact on Drilling Operation

If the cooling of the drilling fluid is not sufficient or the described mitigation and counteractive measures fail, a loss of drill pipe pressure with changes in annular pressure, the loss of large volumes of drilling fluid, or the total loss of drilling fluid returns will cause an underground blowout. Blowouts are the most spectacular, expensive, and feared operational hazards in the whole drilling process. Thus, they may result in costly delays in the drilling program, may cause casualties, serious property damage, and pollution. That is why the risk impact factor is determined to be 5.

5.3 Circulation Losses

Lost circulation can take place in naturally occurring fractured, cavernous, sub-normally pressured or pressure depleted formations. Induced losses can occur from mechanical fracturing due to pressure surges while breaking circulation. In all cases of lost circulation, measures should be taken to keep the hole full. The borehole can be filled with either light drilling fluid or water. A loss of fluid returns will lower the hydrostatic head of the drilling fluid in the wellbore, thereby possibly inducing a kick. The influx fluid will then flow to the surface or into the zone of lower pressure. Loss of returns while trying to kill a kick can develop in an underground blowout. If a kick is impending or an underground blowout has started, a barite plug may be effective in isolating the thief zone from the kick (Baker Hughes, 1995). In addition, fine sealing material may be used to control slow losses instead of coarse materials that may plug the bit and choke valve or choke. Occasionally, a coarse sealing fluid may be used when bullheading down the annulus. Afterwards, the lost circulation zone should be sealed once the loss zone has been isolated from the influx zone.

On the other hand, if the drillhole intercepts a major permeable fracture zone at depths between 2.4–3.5 km, and that fracture zone produces superheated steam, every effort should be made to study it thoroughly before casing it off. Even though such additional activities would delay the completion of the drillhole and increase its costs, ignoring such an opportunity could risk the success of the project, as there would be no guarantee that another major permeable zone would be found at a greater depth (Fridleifsson et al., 2003b).

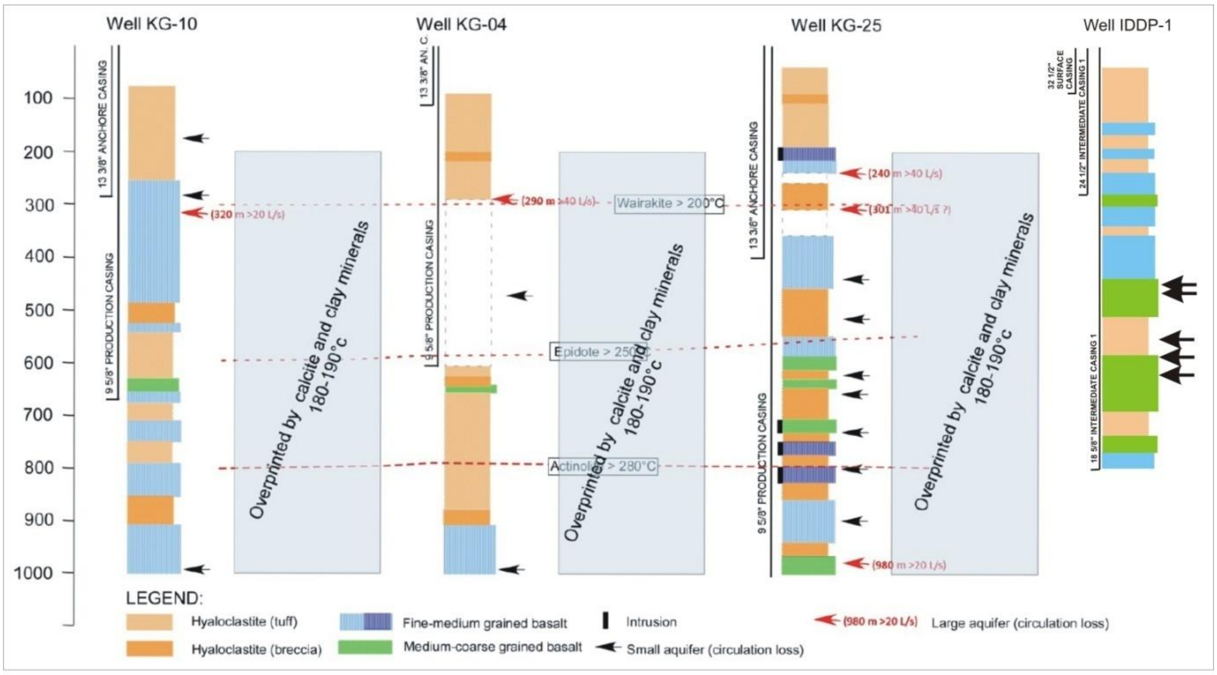

Fig. 33: Profiles of wells KG-10, KG-4, KG25 and IDDP-1 (13.12.2008) with lithology, casing program and circulation loss zones (LVP 2008a, modified).

Circulation losses can be expected at all depths of the IDDP-1 well, but mostly one would expect relatively narrow fractures at intrusive rock contacts within the complex. Intrusions of intermediate andesitic composition can be expected. Most of such fractures have already sealed by mineral precipitates, and will probably not be detected during drilling. Only fracture permeability is expected. Most loss zones are expected to be small due to secondary minerals, but some fracture can be quite open, especially near young subvertical dikes. In general the nature of loss zones at temperatures above 400°C is unknown. Gas content at high temperatures could be quite high and could mix with the drill fluid and expand upon a decrease in pressure.

Figure 33 shows circulation loss zones from a well cross section including the new IDDP-1 drill site. As is inferred from these well data, possible zones of circulation losses are at approximately 240, 300 and 980 m depth. The actual circulation losses that occurred during the drilling of the second stage of IDDP-1 from 340 to 660 m are shown in table 6.

Tab. 6: Overview of measured circulation losses during drilling of 2nd stage of IDDP-1 (ISOR, 2008b).

Depth [m]	***Total Flow [l/s]***	***Circulation loss [l/s]***
340	63	1
350	63	2
413	63	2
426	63	2
437	63	2
457	63	7
466	63	8
474	63	5
476	63	3.5
480	63	3.5
490	63	3
504	63	3
518	63	3
534	63	3
548	63	5
565	63	3.5
573	63	3.5
588	63	3
596	63	5
618	63	8
620	45	3
630	61	2.5
640	61	2
648	61	2
660	58	2

Taking into account that the KG-25 well was drilled with only water as drilling fluid, a comparison with the circulation losses in the IDDP-1 well, which is drilled with drilling mud shows that the circulation losses are almost negligible. Zones of little circulation losses in the IDDP-1 well are at 457-466, 548, 596-618 m. The circulation losses did not exceed 8 l/s and were in most cases below that mark. The comparison of these circulation losses from the surrounding wells and the first 800 m of well IDDP-1, however, showed a good correlation of aquifers at expected depths. The data from well KG-25 is an especially good guideline for predicting potential circulation loss zones in the IDDP-1 well. Table 6 gives potential circulation loss zones for the IDDP-1 well, which can probably occur at the same depth range according to the local trends.

Referring to data from well KG-25, major feed zones were detected at two depth intervals. The upper zone is above 1400 m depth in a formation of multiple basaltic intrusions with temperatures around 195°C and also further down at 1970 m (340°C). At the well's discharge peak, 19.5 kg/s of 195°C water was discharged from the feed points above 1400 m and 25.4 kg/s of steam and 3.3 kg/s of water from the lower feed points (Hauksson, 1991). The lower feed zone is close to the well bottom at 2070 m depth with a temperature of 344°C. In addition to those major feed zones a few minor feed points were detected, which are shown in the following table.

Tab.7: Circulation loss zones in Well KJ-25, 2105 m deep, X [m]: 602562, Y [m]: 581533, Z [m y. s.]: 549.9, Feed zone category 1: < l0 l/s, Feed zone category 2: < 20 l/s Feed zone category 3: > 20 l/s

Depth [m]	***Elevation [mbsl]***	***Lithology***	***Feed Zone Category***
465	84.9	Basalt	2
520	29.9	Basalt	1
625	-75.1	Basalt	1
660	-110.1	Tuff	1
725	-175.1	Dolerit intrusion	1
795	-245.1	Tuff	2
855	-305.1	Tuff	1
890	-340.1	Basaltic breccia	1
905	-355.1	Fine to middle grain basalt	1
955	-405.1	Basaltic breccia	2
980	-430.1	Basaltic breccia	1
1005	-455.1	Basaltic breccia	1
1030	-480.1	Fine to middle grain basalt	1
1060	-510.1	Fine to middle grain basalt	2
1230	-680.1	Middle to coarse grain basalt	1
1400	-850.1	Multiple basaltic intrusions	2
1420	-870.1	Dolerit intrusion	1
1460	-910.1	Dolerit intrusion	1
1565	-1015.1	Boundary layer dolerit to basalt	1
1580	-1030.1	Boundary layer dolerit to basalt	1

1820	-1270.1	Dolerit intrusion	1
1855	-1305.1	Boundary basalt to surt berg	1
1920	-1370.1	Fine to middle grain basalt	1
1970	-1420.1	Boundary layer dolerit to basalt	1
2010	-1460.1	Boundary basalt to acidic intrusion	1
2050	-1500.1	acidic intrusion	1
2070	-1520.1	acidic intrusion	3

5.3.1 Risk Probability

The many fractures and associated circulation loss zones in the shallow part of the IDDP-1 well and the predicted deeper permeable zones in the reservoir have been formed by recent and modern stresses. Those trends are also likely to occur at greater depths. Fracture densities from core observations of other geothermal drilling projects show similarities between shallow and deep reservoirs in terms of fracture distribution. Although the deep reservoirs, due to the higher litho-static pressure are less permeable, the fracture density is not necessarily lower (Muraoka, 1998). Also, the great difference of temperatures in the two reservoirs seems to be independent of fracture density. Therefore the risk of meeting severe circulation loss zones (losses of drilling fluid exceeding more than 20 l/s) is high at all depth intervals and assessed to be 80%.

5.3.2 Impact on Drilling Process

Loosing greater amounts of drilling fluid through fractured zones can lead to getting the bottomhole assembly stuck and loosing the ability to cool the drilling equipment sufficiently. This can cause severe damages to the drilling equipment and casing string and is therefore assessed with an impact factor of 4.

5.4 Coring

Different drilling options and well designs were evaluated in the planning phase in order to get as much coring done as possible, but mainly for financial and technical reasons a spot coring program for the final section between 3400 – 4500 m was favoured over a continuous coring below 2400 m depth with a hybrid coring system. The first proposal for a coring program suggested a 4“ diameter hole cored with a mining-type wireline core barrel. The hope was that by circulating large quantities of cold water down the well during coring, that the temperature inside the well would stay below 250°C, allowing the use of conventional drilling and coring techniques and practices. So the amount of circulating drilling fluid is the key to maintaining an appropriate bottom hole temperature for the drilling equipment. In terms of coring, this principle is put into question due to the reduced circulation capacity in the borehole during the coring process. Because of the reduced space in the borehole due to the standard coring assembly, the circulation rate is reduced down to a seventh of the median circulation rate during conventional drilling. Results obtained by modelling with the STAR program (Huang, 2000) showed that a conventional well drilled with an 8-1/2” bit and water could be cooled to at least half the bottom hole temperature, whereas a cored hole receives almost no cooling due to the small circulation rates of 3-5 l/s during such drilling (Fridleifsson et al, 2003b).

The actual plan is now to drill spot cores anticipated from both the expected transition zone to supercritical from 2400-3500 m depth, and from within the supercritical zone itself between 3500-4500 m. The final section from 3400 – 4500 m is drilled as a 8 ½“ hole and spot cores will be taken with a new developed coring barrel. In November 2008 a successful trial spot coring test was performed at 2800 m depth in the production well RN-17 B at Reykjanes.

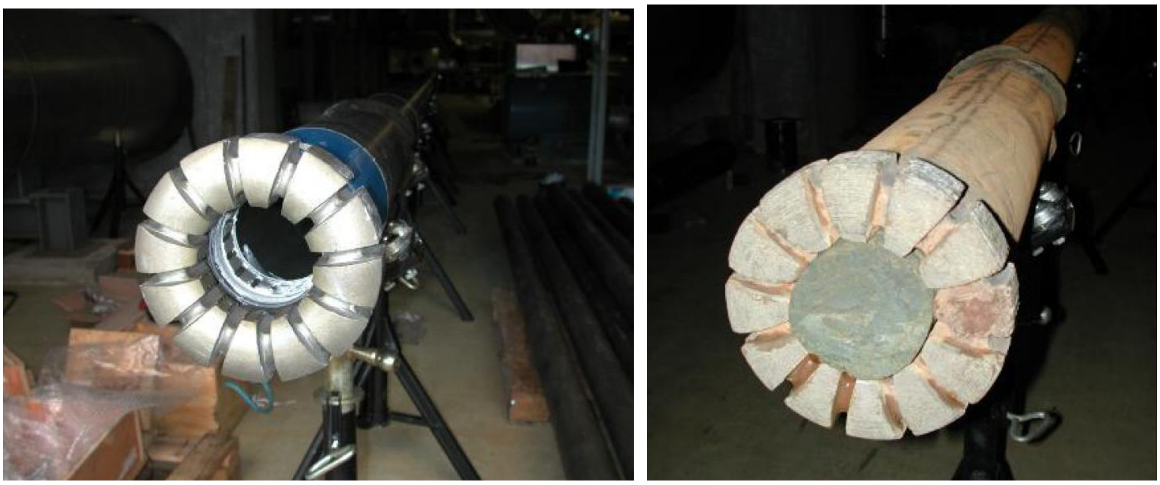

Fig. 34: Left: core bit and the core catcher before test run, Right: after test run, core was out of the hole some 11 hours after coring. One tooth damaged, otherwise a healthy bit and a core inside the barrel (Thorhallsson, 2008).

The core test was performed in an open hole at 35° inclination with newly built coring equipment. The main benefit of the core barrel is its unique feature to enable much greater water flow-rates for cooling during coring, up to 40 l/s, as compared to conventional core barrels with only 3-5 l/s flow rates (Thorhallsson, 2008). The core recovery rate was nearly 100% and only minor improvements on the existing drilling equipment is needed before further spot coring in the IDDP-1 well in Krafla can take place. To increase the resolution of the drilling parameters during coring, minor adjustment on the drilling panel are necessary before the next coring operation in Krafla can start. The 8 ½“ x 4“ core barrel is from Rok Max and the bits are from Geogem; both companies are located in the UK. The inner barrel bearing guides are designed with greater tolerances to compensate for the high temperature environment. For blowout protection, a check valve is built into the top of the barrel sub. The core bit is of the diamond impregnated type, with large cut-outs for assuring a high circulation flow. The core bit experienced some 280°C during test coring, and the entire operation took ca. 33 hours rig time for a 9.3 m coring track (Thorhallsson, 2008).

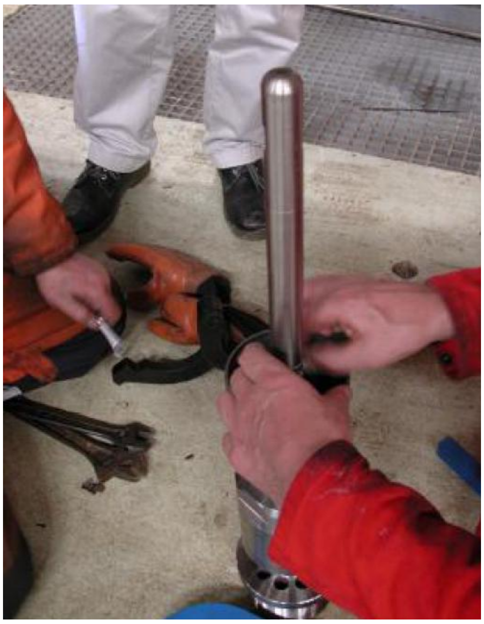

Fig. 35: Chamber for temperature monitoring tools during coring (Thorhallsson, 2008)

5.4.1 Risk Probability

The risk of getting stuck in the hole or significantly damaging the coring equipment downhole due to the high temperature environment is severely reduced by running higher circulation rates during coring. But the risk also increases by meeting circulation loss zones or weak formations. In both cases a loss of circulation fluid could lead to total failure of the coring procedure. The risk of meeting weak formations in greater depths is due to the pressure environment, and is almost negligible, but the risk of losing too much drilling fluid during coring in a feed zone is assessed as likely and therefore was assessed to be 60-75%. At least in the upper 2100 m those possible feed zones can be inferred from the surrounding wells (see chapter 5.3). In the unlikely case that coring will be deployed in the upper 2100 m, probable problematic zones can be spared.

5.4.2 Impact on Drilling Process

Different impacts on the IDDP have to be considered in terms of coring operations. If the rate of penetration while coring is too low over a longer time frame, which means that the benefit/cost ratio is no longer justifiable, the coring operation might have to be stopped. In case it isnot possible to maintain a sufficient drilling fluid circulation and the risk of an underground pressure blowout increases, even with the advanced coring system described above, the coring operation has to be stopped immediately in order to prevent bit burning, insufficient borehole cleaning and kick hazard. In both cases the impact on the drilling process is rather small and therefore assessed with an impact factor of 1. However the loss of scientific opportunities by the lack of core investigation might be rather significant, but that is not subject of this assessment.

A detailed and comprehensive risk assessment for the coring operations associated project risks, pre-drilling and spot coring section risks done by the coring consultant of LVP can be referred to in the appendix: Coring Risk Assessment.

5.5 Borehole Failure

There are several factors which control the condition of the wellbore. There are mechanical influences related to damaging and removing the rock caused by the drill bit, stabilizers, and drilling fluids used during the well construction. These parameters control the initial geometry of the wellbore, and while they can cause some rugosity, they rarely lead to total wellbore failure. The state of stress around the wellbore after bit penetration is another matter. The wellbore state of stress is a function of the initial earth stresses prior to penetration, the wellbore geometry, the rock properties, and the current pressure inside the wellbore imposed by the drilling fluid.

Wellbore stress generated by annular pressure (or drilling mud) controls the opposite condition. In case the wellbore pressure becomes too high, either leakage of annular fluid into pre-existing fractures or tensile failure of the rock resulting in a hydraulic fracture will occur. While this may be highly desirable as an intentional form of reservoir stimulation, it is not so in the upper parts of the wellbore and should be avoided.

In geomechanical terms the wellbore failure is defined by wellbore breakouts, which means that parts of the borehole wall cave in due to stress concentrations at the wall itself that result in shear failure. The width of the breakout depends on stress conditions, rock properties and drilling fluid pressure. If the breakout width exceeds approximately 90° to 100°, it is highly likely that the rest of the borehole wall will collapse (washout). Consequently, if the stress and mud conditions are right, tensile cracks can be created at the points along the wall that are in tension (Fig. 36).

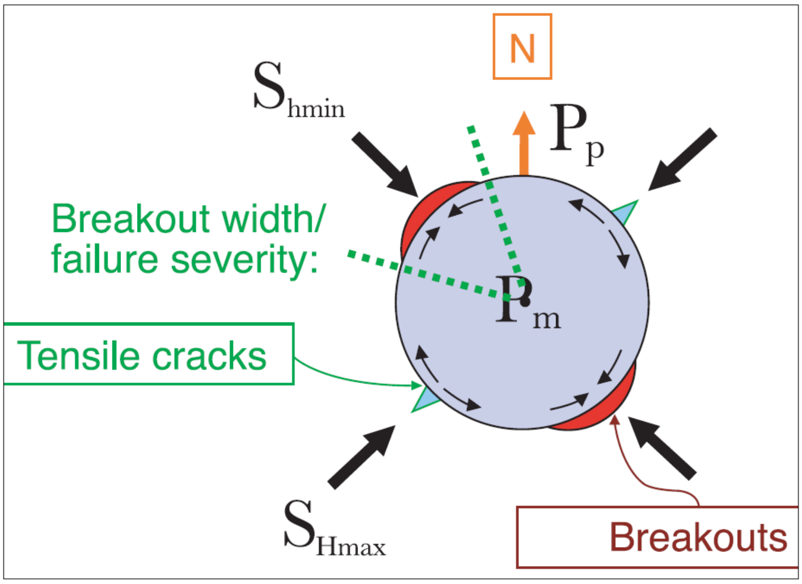

Fig. 36: Wellbore breakouts from under right stress, rock and mud conditions, Pm: mud pressure, Pp: formation pressure (Brehm & Ward, 2005).

Adjustments to the resulting mud weights and casing points come solely from offset well experience, necessary because the mud weight required to prevent both wellbore failure and lost circulation rely on wellbore trajectory and regional stress state. Common data sources for modelling possible wellbore failures can include anything from seismic to core tests. But before using a model to predict mud weights needed to prevent wellbore failure in a planned well, the model must first be able to predict failure, or lack of failure, in offset wells where failure actually did or did not occur. Therefore a detailed drilling history is needed. Borehole instability as well as lost circulation are both highly dependent on the stress state around the borehole. The three principal stresses are the vertical stress S_v or "overburden", the maximum horizontal stress S_{Hmax}, and the minimum horizontal stress S_{hmin}. The relative magnitude of each of these three principal stresses determines the type of geomechanical faulting stress regime. The orientation of these stresses also has an impact on the position of the wellbore failure on the wellbore wall as well as implications for optimal drilling directions. The effective rock strength and other rock mechanical properties play a significant role in an effective geomechanical model, but, like in our case, this information is often not available, warranting the use of empirical methods.

When designing mud weights the point is not to select values which prevent all breakouts. The point is more to keep the breakouts at an acceptable limit, which is described as the critical breakout width (CBW). The CBW is dependent on the borehole deviation. Cleaning in vertical boreholes is much easier than in deviated ones, so vertical boreholes can withstand higher failures. CBW's of 90° are acceptable in vertical holes (Brehm & Ward, 2005) like the IDDP-1.

After designing the casing plan, an appropriate mud weight plan should be tested against the safe operation mud window. Furthermore, a determination of how much borehole azimuth and inclination are affecting the operation mud window should be made. By defining the lower boundary of the operation mud window as the higher value of either the pore pressure or collapse pressure of the borehole, mud weights will prevent excess wellbore failure as well as preventing formation kicks or flows. Due to the fact that the borehole collapse pressure is dependent on the wellbore trajectory at a particular depth, it might be considered that changing the well trajectory can improve the operation mud window and so increase the chances of a successful completion of the drilling operation.

Due to the lack of data in terms of rock properties and stress field analysis, the assessment of wellbore failure can only be based on regional fault and fracture models existing in literature. As was inferred from the regional geological maps, the main fault direction is NE-SW with minor fissure swarms stretching SSW to NNE, which leads to the conclusion that a borehole intersecting with one or both of these main fault/fissure patterns will have breakouts most likely in NE-SW and SSW-NNE directions, possible at any depth. Analysed calliper logs from well KG-25 and the first 800 m of the IDDP-1 well confirm this assumption.

Another hint that allows the detection of possible zones of wellbore failure is the distribution of fracture zones and permeable fractures, which can be inferred from lost circulation zones encountered during drilling, examination of cores and cuttings, and distribution of micro earthquakes. By processing this information possible zones of wellbore failure can be detected and the mud engineer can act accordingly to adjust the constitution of the drilling mud to prevent excessive mud weights.

For those intervals that are also spot-cored, this uncertainty can be resolved by direct observation and measurement of the fractures obtained by core analysis. As already stated in chapter 5.3 the deep reservoir is probably less permeable, but the fracture density is probably not lower as in the upper reservoir. The great difference of temperature in the two reservoirs is also expected to be independent of fracture density.

5.5.1 Risk Probability

The current and recent stress states in the Krafla geothermal field can probably be deduced from analysis of geophysical logs, micro earthquake data, ongoing seismic studies and the investigations of exposed fractures and veins. This information in turn permits an assessment of the stress field leading to the statement of most probable borehole failure conditions. But without this data only general interpretations like those stated above are possible. Based on this information, the probability of intersecting fractured zones, which favour borehole failure, is given at any depth independent of temperatures. This risk is assessed to 50%.

5.5.2 Impact on Drilling Process and Mitigation Measures

If the wellbore pressure is improperly adjusted at any point during the drilling and well completion process, the wellbore may experience degraded functionality or become entirely dysfunctional. All but the most minor wellbore failures have a significant impact on the completion of the well. Thus the impact factor is determined to be 3.

As stated above, a good geomechanical model based on the investigation of rock properties on the drilling site is of major importance. Pre-drill planning incorporating a geomechanical analysis of stress and wellbore failure to minimize stability problems has been demonstrated to be extremely cost-effective for wells (van Oort et al., 2001). During drilling, the geomechanical model can ensure, by giving the right mud weights, that a functional wellbore is constructed efficiently and free of formation fluid influx, drilling fluid loss, or wellbore instability. However, data uncertainties can be quite large due to a number of factors, and thus there are often large uncertainties in the predictions of the safe range of mud weights appropriate to avoid stability problems. By applying Quantitative Risk Analysis (QRA) software it is possible to quantify the mud weight uncertainties using reasonable estimates of the uncertainties in the input data, and to establish the benefits of additional measurements to reduce those uncertainties and thereby reduce the risk of later drilling problems (Moos et al., 2003).

It is also recommended to monitor borehole instabilities from repeated BoreHole TeleViewer (BHTV) logging, as long as the temperature constraints allow doing so.

5.6 Casing Failure

To obtain a sustained flow of steam from a reservoir, it is necessary to choose an appropriate diameter for the production well. Additionally, it is necessary to provide adequate casing at correct depths to prevent hot water from higher formations from entering into the well. For the sake of longevity, the casing must be capable of withstanding wear, corrosion, high temperatures and attrition due to friction and vibration. The temperature to be expected in the well is higher than in conventional geothermal wells and much higher than is experienced in the petroleum industry. The bottomhole temperature is assumed to be 550°C and the flowing well head temperature is estimated to be 500°C. The pressure is expected to be 25 to 27 MPa (3600 to 3900 psi). In the design of geothermal wells the guidelines of the petroleum industry have been followed but when the temperature exceeds 150°C the geothermal industry have been using ASME and ASA codes as suggested in NZS 2403:1991, the New Zealand Code of practice for deep geothermal wells.

The values to be used for well design are based on the following assumptions, as stated in the feasibility report from 2003:

- The subsurface temperature values will follow saturation conditions for column of boiling water down to the critical point (CP) here assumed to be at 3500 m depth.
- Below the CP two temperature profile scenarios are inspected.
    - First is assumed that the temperature will rise linearly from 374°C at the CP to 550°C at 5000 m and
    - secondly isochor condition is assumed which will render a bottom hole temperature of 390°C.
- The bottom hole pressure is assumed to be 25 MPa and 26.7 MPa respectively.

These temperature changes cause strain (tension or compression) due to hindered thermal expansion of the casing, partially offset by a possible state of traction that may have been produced during the hardening of the cemented annulus. Thermo-mechanical modelling before and during drilling to forecast potential damage can be a solution to minimize thermal stresses.

The result of the casing design is shown in figure 37 and is summarized in the following list (Fridleifsson et al, 2003b):

- For the materials considered for the top part of the anchor casing 2,5Cr-1Mo (SA-213 T22) is considered the best suited material for the time being. The wall thickness of the 13-5/8" anchor casing is 16 mm and for the lower part of the 13 3/8" anchor casing it is 13 mm.
- Thick walled grade K-55 casing with premium connections is the best suited for high temperature operation and is planed for the other part of the casing program. Premium connections with metal to metal seals and of higher grade material of quenched and temper steel containing molybdenum is considered to render adequate seal and strength.
- Successful cementing of the casings is the basis for safe operation of the well and thermal cycling should be kept to a minimum to enhance the lifetime of the well.

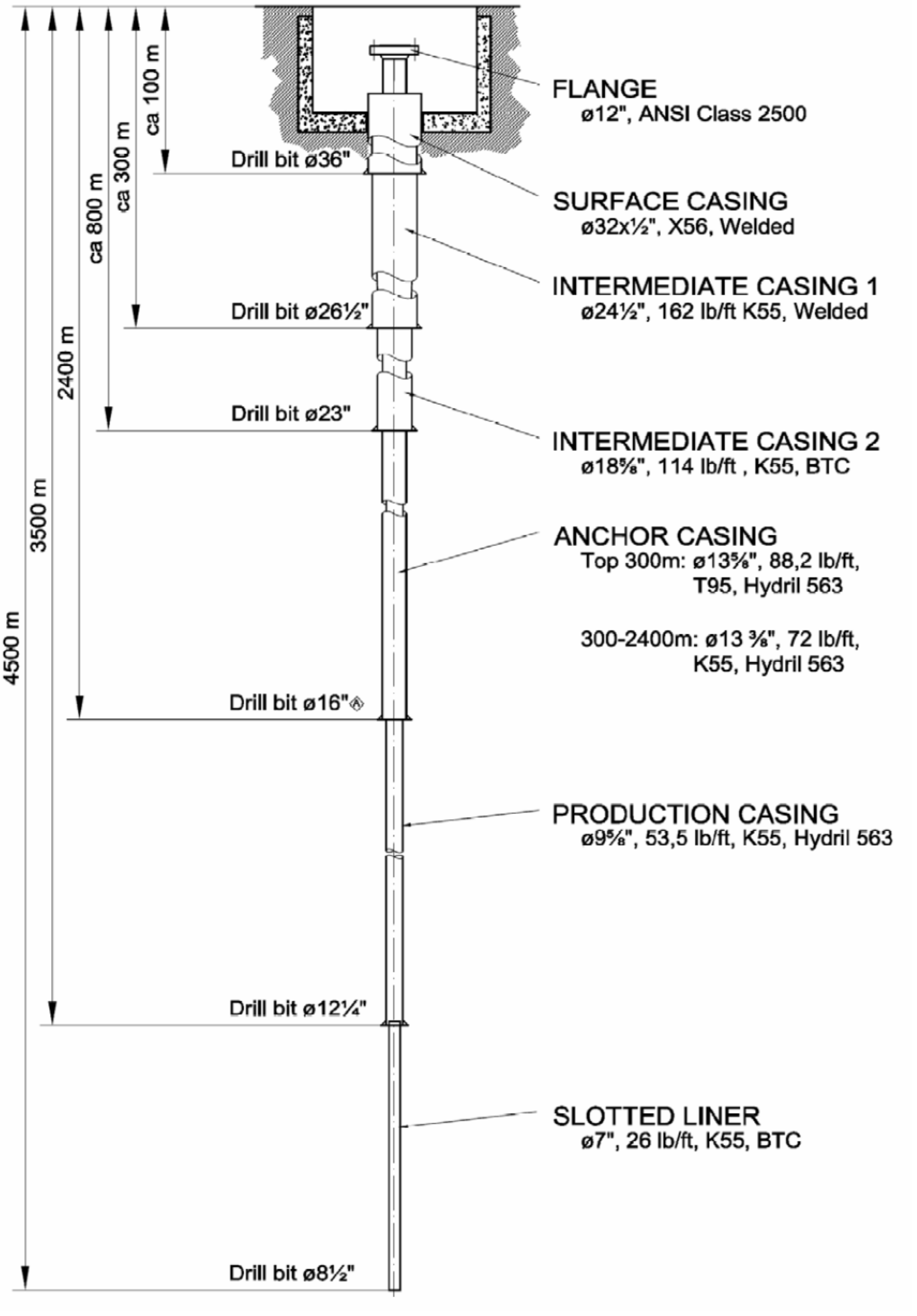

Fig. 37: Casing program of the IDDP-1 well in Krafla (LVP, 2008a).

The actual well design with drill bit and casing diameter, casing weight and wall thickness, material selection, connection types as well as collapse and burst strength is given in the following table.

Tab. 8: Casing program of well IDDP-1 (LVP, 2008a).

	Depth [m]	*Drill Bit Diameter [in]*	*Casing Diameter [in]*	*Thickness / Weight [lb/ft]*	*Min. Drift [mm]*	*Material*	*Connection Type*	*Collapse Strength [MPa]*	*Burst Strength [MPa]*
Surface Casing	0-90	36	32	0.5"	6	X56	Welded	7	8
Intermediate Casing I	0-300	26 1/2	24 1/2	162	585.8	K55	Welded	5.7	17.0
Intermediate Casing II	0-800	23	18 5/8	114	438.9	K55	Welded	9.8	20.6
Anchor Casing (upper part)	0-300	16 1/2	13 5/8	88.2	311.2	T95	Hydril 563	29.4	52.6
Anchor Casing (lower part)	300-2400	16 1/2	13 3/8	72	311.2	K55	Hydril 563	15.4	25.5
Production Casing	0-3500	12 1/4	9 5/8	53.5	215.9	K55	Hydril 563	35.4	37.6
Slotted Liner	3500-4500	8 1/2	7	26	156.2	K55	BTC	9	10

A sudden change in the diameter of the casing pipe at the joints causes turbulence in the high-speed steam flow and results in the erosion of the upper corners of the joints as well as the inside surface. This can be avoided by the use of internal flush-butt joints, in which the inside diameter does not change suddenly (Gupta & Roy, 2007). However, for the IDDP casings the inside diameter is constant for each casing string.

In 1990 Maruyama et al. asserted that casing couplings can withstand temperatures as high as 354°C. Their findings are that premium connections with metal-to-metal coupling seals provide excellent seal tightness in thermal wells at temperatures up to the maximum testing temperature of 354°C. Further, it was observed that the seal integrity of premium connections can be enhanced by the use of couplings that are thicker and/or of higher-grade material than the pin and by using couplings made of quenched-and-tempered steel containing molybdenum (Fridleifsson et al, 2003b).

It was decided to weld the connections of the first three casing strings, instead of welding only the connections of the first two strings, and then use BTC connections for the intermediate casing II. It was assumed that the additional welding sections will not increase the risk of structural failure of these sections, because the production zone is considered to be sufficiently distant.

The welding procedure is stated in the final drilling design program as follows: (LVP, 2008a)

- An electrode suitable for welding K55 (C: 0.31%, Cequ: 0.61%) will be used. The electrode rods shall be handled according to the instructions of the manufacturer. This includes baking before the welding and appropriate storing.
- The casing shall be preheated to 200°C, 100 mm from the welding area
- The wall thickness of the casing is 16.1 mm. The welding shall be carried out in at least three circumferential layers.
- Care shall be made to maintain constant temperature during welding
- Before the casing is welded a sample using the welding procedure above shall be made and tested.

The welding shall comply to group C according to IST EN 25817. The casing shall be equipped with float shoe, float collar and centralizers. Strict inspections on the material and welding process are recommended.

10.1.1 Risk Probability

The combination of corrosive resistance alloys and the high-strength offered by the chosen steel types has shown good results in high temperature and high pressure wells even in a sour geochemical environment around the world for several decades now. Also, the designed casing connection types are appropriate to withstand the high temperature conditions in the IDDP-1 well, although the risk of failure is slightly increased by the decision to weld the connection of the intermediate casing II. Therefore the general failure probability for the casing program is assessed to 30%.

10.1.2 Impact on Well Completion

A failure of the casing can lead to serious delays in the drilling operation due to time consuming fish back actions of failed casing parts. In the worst case, if fishing is not possible or not successful, a cement plug has to be set and a side track has to be drilled, which will cause a serious increase in drilling costs, which is why the impact factor is assessed to be 4.

10.2 Cement Failure

Proper cementing of geothermal wells requires that the cement slurry should rise uniformly and continuously from the casing shoe to the ground level. Because it is envisaged that it will be difficult to cement the entire casing in one stage, multistage cementing shall be applied. Thereby a stage tool is placed in the casing string just above the previous casing shoe. The first stage in cementing will be through cementing string through the float collar and float shoe and up to the stage tool. The second stage is present if losses are to be dealt with, between the bottom and the stage tool; a squeeze job from the stage tool can be done with the annular preventer closed. The third stage is filling up the annulus (between casings) from the stage tool. It is assumed that this more expensive and complicated multistage cementing technique will pay off in terms of securing a proper cement refill and connection of the annular space with the borehole wall or respectively with other casing strings.

Ordinary cement is adequate for temperatures up to 150°C, but to resist higher temperatures, silica is mixed with it. In geothermal wells where steam is accompanied by low-pH hot water, it is necessary to use acid-resistant cement. In the following table the components for the cement slurry designed for the intermediate casing I and II are stated.

Tab. 9: Cement slurry designs and properties for intermediate casing I and II (LVP, 2008a)

Cement slurry design for intermediate casing I and II	
Slurry volume	44 m^3
Cement	57 tons
Portland Cement	100 kg
Silica flour- 325 mesh (Sikron M - 300)	40 kg
Expanded perlite (Harborlite 20 x 30)	2 kg
Bentonite (Wyoming)	2 kg
Water loss additive	0.4 kg
Retarder (adjust to requirements)	0.2 kg
Properties	
Slurry density	1.65 kg/l
Freshwater volume	800 l/t
Slurry volume (yield)	1400 l/t

Factors useful for the prediction of the risk level in cementing are bottom hole static temperature (BHST), offset experience, well deviation, water depth, temperature gradient, access to MWD temperature data, thickening time requirements and waiting-on-cement time requirements. Those parameters listed in table 10 provide a basis for estimating the overall level of risk associated with cementing temperature uncertainty. A high risk level on one or more of these parameters may warrant the application of appropriate risk mitigation measures. The chosen cement class G will be tested by Schlumberger in Italy in terms of adding appropriate additives for the high temperature resistance capability.

One way to decrease the degree of temperature uncertainty is to collect and analyse additional temperature data while the well is being drilled. This data is most commonly obtained by MWD but could also be collected by a memory temperature sub placed in the drill string. For more detailed information on limitations and techniques for how to obtain temperature data in very high temperature environments see chapter 5.1.3. The annular temperature data acquired from MWD can be used to calibrate a mathematical simulator, which requires the simultaneous recording of additional parameters of pump rates, circulation times, BHA depths and fluid inlet and outlet temperatures (Stiles & Trigg, 2007). A close match between the prediction from the model and the actual MWD data will increase confidence in the degree of accuracy of the simulator for cement design. But one should consider that the heat generated by the drilling process with a rotating drill bit and drill string may increase the MWD temperature, which will not be considered in the simulations. This problem can be minimized by making a comparison on data gathered while circulating off bottom without pipe rotation.

Tab. 10: Cementing temperature risk matrix, BHST: bottom hole static temperature, MWD: measurement while drilling, WOC: waiting on cement (Stiles & Trigg, 2007).

Parameter	Low Risk	Medium Risk	High Risk
BHST	< 125°F	126 - 175°F	> 175°F
Offsets	> 5 Wells	1 - 5 Wells	None
Deviation	Vertical	<25° Angle	≥ 25° Angle
Water Depth	< 1000 ft	1000-2500 ft	> 2500 ft
Temp Grad	<1.2°/100 ft	1.2 - 1.5°/100 ft	> 1.5°/100 ft
MWD Temp	Yes	No	---
Job Time	< 2 hrs	2 - 4 hrs	> 4 hrs
WOC Time	> 48 hrs	8 - 48 hrs	< 8 hrs

Large variations in thickening time are noted across the temperature range, which can lead to job failure and consequently redesigning the cementing procedure with different types of retarder and high temperature additives. Synthetic retarders with lower sensitivity to temperture variations may provide a good solution. Care must also be given to other slurry properties, such as fluid loss and gel strength development. If the cement system can be designed to have an adequate thickening time at the bottomhole circulation temperature (BHCT) well above what is predicted and still attain a minimum compressive strength in an acceptable time span at the BHST at the highest point of interest, then the risk of failure will be graetly reduced (Stiles & Trigg, 2007).

10.2.1 Risk Probability

Refering to the cementing temperature risk matrix in table 10, almost all given parameters are in the range of or even above the high risk criteria classification. By applying the new multistage cementing method, the risk not to be able to cement the whole annular space up to the top is considerably reduced. On the other hand, using cement with a density of 1.9 kg/m^3 will put more strain on the pumps and casing. Therefore the overall cement failure probability is assessed to 60%.

10.2.2 Impact on Well Completion and Contingency Measures

In case of cement failure the drilling operations are delayed, which causes the common increase in drill rig costs as well as additional costs in terms of the cementing job. If the cement does not reach the surface again, even with the multistage cementing technique, cementing from the top can be a solution, although there are great uncertainties in terms of a proper refill of the annular space between borehole and casing. In the worst case the casing has to be penetrated and recemented. The impact factor in case of cement failure is assessed to 3.

10.3 Failure of Rig Instrumentation and Water Supply

Rig Instrumentation

A modern drilling information system is essential for the drilling crew to react immediately to occurring problems. Having access to historic drill data is important to evaluate the recorded new datasets. The surveillance software requires a lot of instrumentation, which in turn requires intensive maintenance work. If used in the right way it will significantly increase the ability to control the well and drilling process and therefore reduce the risk of drilling equipment failure and blowouts. The used rig instrumentation system will record the following parameters in digital format:

Tab. 11: Recorded rig instrumentation data (LVP, 2008a)

Property	Unit
Time	s, min, h, d
Depth of bit	m
Height of top-drive	m
Rate of penetration	m/h
Weight of drill string	t
Weight on bit	t
Pump strokes of mud pumps	SPM
Cumulative mud flow in	l/s
Pump pressure	bar
Casing pressure, wellhead	bar
Temperature of mud in	°C
Temperature of mud out	°C
Differential mud temperature	°C
Temperature of wellhead	°C
Torque top drive	daNm
Rotary speed top drive	rpm
Bit rotation (calc), mud motor	rpm
Tank levels	m
Tank volumes	m^3
Flow line, paddle or Mag. flow meter	% or l/s

Bit hours	h
Total bit revolutions	rev
Make-up torque	daNm

Water supply system

As it is stated in the drilling contract the Owner will operate the water supply system and be responsible for laying drilling water mains right up to the drilling site from a water supply facility, which has the capacity for approximately 70 l/s of about 15°C water per pump. The drilling company is responsible for connecting the water mains to its appropriate equipment as well as supplying all material needed for that. The water supply system consists of two water supply wells about 3 km away from the drilling site, with electric submersible pumps installed and two booster pumps mid way between the site and the wells. Both systems are fed by an electric current from the Krafla Power Station mains. The capacity of the water supply system pumps is sufficient to pump the required quantity of water to the drill cutting, water and mud tanks of the drilling rig (LVP, 2008a). In case of an emergency, diesel generators will be standing by for each system. With bypass, the booster pumps can also pump separating water from the power plant.

10.3.1 Risk Probability

The risk of failures in the instrumentation equipment as well as in the water supply system is considered to be low. A reliable surveillance and contingency plan is worked out, and if one part of the instrumentation or water supply structure fails, other readings and measurements will probably indicate where the problem is, so that the drilling crew or water supply operators can act immediately to replace broken parts. A total failure of the whole instrumentation or water supply system is considered to be unlikely. Therefore the overall risk for both factors is determined to be less than 20%.

10.3.2 Impact on Drilling Operation

Inaccurate readings due to broken or malfunctioning instrumentation, as well as reduced or even interrupted water supply can lead to severe problems during the drilling and well completion process, including blowout hazard and damages to the drilling equipment due to insufficient circulation fluid or maladjusted drilling parameters like mud weight, weight on bit, etc. But as stated above those malfunctions can be detected quite easily and quickly resolved so that the impact of failures in the instrumentation and water supply system is assessed to the factor 2, assuming that there are sufficient and appropriate spare parts available on the drill site.

11 OVERVIEW MATRIX AND CONCLUSIONS

NOTE 1:

The natural geological risks arising from volcanic and seismic activity are considered to be comparatively minor important factors in contrast to the well completion process due to their low probability, although their possible impact might be very serious. The risk in meeting insufficient permeable zones is assessed to be likely, but by locating and investigating upper possible feed zones it is conceivable to produce superheated steam from those zones.

NOTE 2:

The main risks are assessed in the hazard of underground pressure blowouts, meeting circulation loss zones and material failures due to the high temperature environment. In addition borehole failure, formation fracturing, cement and casing failure as well as problems during coring operations are assessed to be likely, but for almost all assessed risk scenarios the failure risk can be reduced or prevented by applying appropriate techniques as well as mitigation and counteractive measures.

NOTE 3:

Due to the lack of reliable data, which also limits the risk assessment, especially for depths exceeding 2 km it makes sense to put some more effort on closing these gaps. To minimize risks and for better predictions it is recommended to investigate rock properties with the help of core samples obtained from outcrops in the drill field in advance of the drilling operation. Stress field, rock permeability, thermal conductivity, geochemical and mineralization data is of particular interest. Also, the preparation of a detailed digital reservoir model could help to understand the behaviour and interactions of the different reservoirs and flow regimes. It can also help to identify the boundaries of the magma chamber in Krafla.

NOTE 4:

The entire IPPD-1 well completion is still a frontier geothermal drilling operation and therefore, in spite of all risk mitigation and prevention measures, an enterprise with great uncertainties but calculable risks. So it is concluded that with a comprehensive risk management and contingency plan most of the discussed hazards can be handled.

IDDP - Risk Assessment for the first IDDP-1 well in Krafla								
Ref.	**Risk denomination**	**Reference chapter**	**Hazard description**	**Consequence description**	**Impact factor**	**Probability**	**Risk reducing measures**	**Actions / comments.**
				Geological Risks				
1	Vulcanic hazards	4.1	Ash deposits, lawa flows, ground movement, access difficulties, seismic activity	Water and electricity supply failure, damages to drill rig, drill equipment and borehole up to mast collapse, fires on the drilling rig, engine failures and total wellbore collapse, casualties	5	< 20%	Monitoring natural manifestation and seismic activity	Depending on volcanic impact: from securing well and drill rig up to abandon drill site
2	Earthquake hazard	4.2	Ground shaking and ground movements, seismic activity	Water and electricity supply failure, damages to drill rig, drill equipment and borehole up to mast collapse, engine failures and total wellbore collapse, casualties	4	< 20%	Monitoring seismic activity and fault movements	Depending on magnitude: from securing well and drill rig up to abandon drill site
3	Sufficient permeability	4.3	Impermeable formation, no sufficient permeability	No charging of supercritical fluids, no production fluid	4	50%	Investigation of upper permeable zones	Utilizing upper permeable zones, reservoir enhancement, hydraulic fracturing, side tracking
				Drilling Risks				
4	Material failure (drilling equipment) due to high temperature / pressure environment	5.1.3	Damages to drill bit, mud motors, drill string up to total failure and loss of drill string, mud gelation	Low rate of penetration, delay in drilling process, increasing costs	3	65-75%	Cooling well with cooled drilling fluid, maintaining a sufficient rate of circulation, using Top Drive	Different material selection, additional cooling
5	Temperature logging	5.1.3	Damages to logging tools	Lack of precise temperature and geophysical borehole data, losing ability of adjusting the drill process to high temperatures lack of scientific data	2	40%	Using appropiate logging tools (HiTi-Project)	Slick-line computer tools, distributed optical-fiber Temperature Sensing, temperature melting tablets
6	Formation fracturing caused by cooling	5.1.4	Hydraulic connections, circulation loss or wellbore instability/ failure	Delay of drilling process, increase of costs	3	50%	Fracture testing, investigation of rock samples to estimate stress field	Reduce cooling (if possible), cementing a plug section and redrilling
7	Formation fracturing caused by high fluid column/mud weight	5.1.4	Hydraulic connections, circulation loss or wellbore instability / failure	Delay of drilling process, increase of costs	3	60%	Fracture testing, investigation of rock samples to estimate stress field	Reducing mud weight (if possible), cementing a plug section and redrilling
8	Underground pressure blowout	5.2	Uncontrolled flow of geofluid from reservoir into the wellbore	Costly delays in the drilling program, may cause casualties, serious property damage, and pollution	5	90%	Pumping cooled drilling fluid into the well at all times; rock investigation to predict rock properties for adjusting BHP	Injecting heavy drilling mud through kill line, close BOP, Running Kill, Bullheading
9	Circulation losses	5.3	Loosing great amounts of drilling fluid, kick hazard	Stucking of the bottom hole assembly, loosing the ability to cool the drilling equipment and well	4	80%	Analyse historic drill data to predict possible circulation loss zones	Barite plug; using light or heavy drilling mud instead of water
10	Coring operation	5.4	Get stuck in the hole, damage significantly the coring equipment downhole	Low rate of penetration, delay in drilling process, increasing costs, loss of scientific data, blowout hazard	1	60-75%	Applying the new coring barrel with increased circulation capacity	Stop Coring process and continue with conventional drilling
11	Borehole failure	5.5	Wellbore breakouts, borehole collapse	Delay of drilling process, increase of costs	3	50%	Geomechanical analysis of stress and wellbore failure, QRA to determine appropriate mud weight, monitor borehole instabilities with BHTV	Cement plugs, redrilling
12	Casing failure	5.6	Casing breakouts, deformation or collapse	Delay of drilling process, increase of costs	4	30%	Strict inspections on material and welding process	Fish back casing, cement plug and side tracking
13	Cementing failure	5.7	No sufficient refill of annular space or adequate thickening time	Delay of drilling process, increase of costs	3	60%	Multistage cementing, Applying synthetic retarders with lower sensitivity to temperature variations	Penetrate casing and recement, cement from top
14	Failure of rig instrumentation and water supply	5.8	Wrong readings, water supply decrease or interruption	Low rate of penetration, damages to drilling equipment, blowout hazard	2	20%	Applying strict inspections, surveillance and maintenance routines	Spare pumps and instrumentation parts available on drill site

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APPENDIX

Content of Appendix

- Location overview map 1 : 5000 (LVP, 2008a)
- Geological Map of Krafla 1 : 25000 (ISOR, 2008)
- Geothermal Map of Krafla 1 : 25000 (ISOR, 2008)
- Casing Design Schematic for IDDP-1 (LVP, 2008a)
- Coring Risk Assessment Matrix (by consultant)