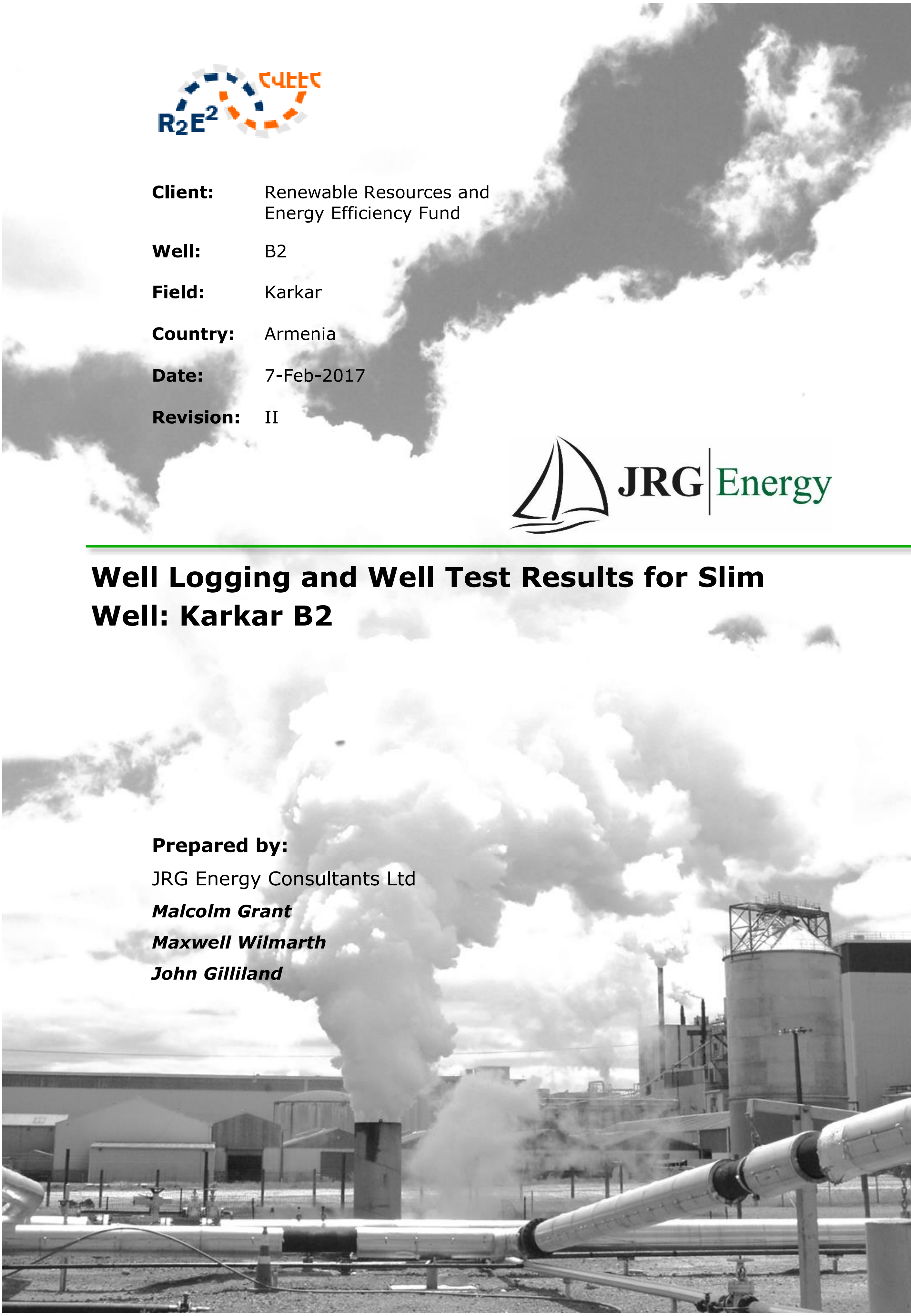

Client: Renewable Resources and Energy Efficiency Fund

Well: B2

Field: Karkar

Country: Armenia

Date: 7-Feb-2017

Revision: II

Well Logging and Well Test Results for Slim Well: Karkar B2

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CONTENTS

TABLES AND FIGURES

I. EXECUTIVE SUMMARY

The Armenian Renewable Resources and Energy Efficiency Fund (R2E2) is exploring the Karkar Geothermal Field to assess the geothermal energy potential of the site. JRG Energy of New Zealand is providing well testing and geoscience services for the project with bank-funded technical oversight by ISOR of Iceland. The first exploration well, B-1, was completed and tested in September 2016. The second well, B-2, was completed and tested in November 2016.

This report summarizes and analyses the resource data collected from well B-2, while referencing analysis from B1. Furthermore, it integrates the newly acquired results into the previous conceptual model for the Karkar Geothermal Field as a whole. Additional conclusions and recommendations are offered for future consideration.

Data from wells B-1 and B-2 support the high temperature gradients and elevated temperatures of the Karkar Geothermal Field first discovered in well B-4. However, it has been observed that both wells display signs of significantly low permeability. Well B-1 had two permeable zones, between 700-815 mMD and 1080-1120 mMD, with a possible minor zone at 1200-1260 mMD, while B-2 had only one testable permeable zone of very low permeability between the interval of 800-900 mMD. A total loss zone observed during drilling at ~1660 m was not able to be tested due to sloughing material covering the zone. Average reservoir temperature at the main permeable depths is between 70-80°C. Permeability of both wells is considered very low compared to typical commercial geothermal reservoirs. However, based on large amounts of debris fill found in the wells while testing, there is a possibility that both wells exhibited lower permeability readings due to debris obstructions. If this is indeed the case, the well permeability can be improved by extensive flowing or reservoir stimulation.

Wells B-1 and B-2, with no additional drilling or alterations, will produce low enthalpy geothermal fluid, around 75°C. The elevated conductive gradient at the bottom of B-2 has proven temperatures >120°C at 1600m, a minimal prediction of 140°C around 2000m, and a possible high end estimate of 160°C at depths of 2000 m if the temperature gradient from depths of 1600 to 2000 m increases due to permeability. By analogy to commercial geothermal fields in similar basement rocks in western Anatolia, temperature gradients could decrease near intermediate aquifers and then increase again with greater depth. Therefore deeper drilling could possibly encounter commercial permeability and temperatures at depths up to 3500 m.

II. INTRODUCTION

Well B-2 was spud on 13-October-2016 at a location in the volcanic depression (basin) ~500 m west of B-1 (Figure 7). The target of the well was the low-resistivity anomaly in the basin and hot geothermal flowing fluid that may have been located in the N-S fault zone (ISOR, 2012). The well was drilled to a total depth (TD) of 1684 m measured depth (MD) and completed on 28-November-2016.

i. Well Data

Table 1: Summary of Well B-2

Well	B2
Date Drilled	28-November-2016
Well Test Date	29-November-2016
Working flange	Recovery tube in BOP
Total drilled depth	1684 m CHF
Production Casing	7": 0 – 716.8 m CHF
Liner	4 ½"; 684.8 – 1678.8 m CHF
RKB to CHF	3.55 m
Max deviation	n/a
Loss zone - TLC	1657 mchf
Loss zone(s) - PLC	n/a

CHF = Casing Head Flange

TLC – Total Loss Circulation

PLC – Partial Loss Circulation

Depth (m CFH)	Hole Diameter	Casing
12	16"	13 3/8" cemented
149	12 ¼"	9 5/8" cemented
720.65	8 ½"	7" cemented
688	6 1/8"	Top of 4 ½" slotted liner
1682.8	6 1/8"	Bottom of 4 ½" slotted liner

CHF = Casing Head Flange

ii. Lithology

Interpretation of cuttings logged by the mud loggers at the wellsite showed well B-2 encountered a quartz monzonite to ~240 m depth underlain by young Quaternary volcanic rocks consisting largely of tuffs with occasional interbedded lava flows to a depth of ~1025 m where the Paleozoic basement rocks were reached. The basement rocks consist largely of mica-schist occasionally interbedded with other types of meta-sediments including dolomitic marble, greywacke, quartzite, serpentinite, and ophiolites. Table 2 below summarizes the lithologies encountered in B-2.

Hydrothermal alteration of the primary lithologies, in general, is of low intensity and the observed minerals indicate low temperature. Smectite alteration was first logged at ~290 m. Higher-grade alteration minerals such as illlite were not observed, however they may exist and could be identified with laboratory analysis of the cuttings. The Paleozoic basement rocks are of course highly altered but this could be due to ancient metamorphism.

Table 2: Summary of well B-2 lithologies.

Depth (m CFH)	Lithology
0-155	No data
155-241	Quart Monzonite
241-1025	Tuffs interbedded with occasional basalt lava flows, andesites, and diorites
1025-1684	Meta-sediments (dolomitic marble, greywacke, quartzite, serpentinite, ophiolite)

CHF = Casing Head Flange

The lithology of B-2 is similar to B-1 with the exception of the shallow quartz monzonite. This quartz monzonite may be the same unit that dominated the logged lithology of the N-4 well to the west (this well has been variously referred to as B-4 and N-4 in the project literature). The difference between B-1 and B-2 lithology reflects the highly variable geology of volcanic provinces. B-1 was drilled in an extensional pull-apart basin which was likely down-dropped relative to the B-2 location and has a deeper basement contact as identified by well lithologic logging and gravity modeling (Georisk, 2012; White et al, 2015).

III. DRILLING OBSERVATIONS

JRG Energy was not involved with the drilling operations directly. A JRG Energy geologist was sent at the end of the drilling of the production section to help with interpretation of cuttings, draw conclusions from drilling reports, and aid in other areas of discussion where needed. The following sections describe these conclusions.

i. Gas

During the drilling of well B-2, little gas was detected by the mud logging unit's gas detectors located above the mud shakers to measure gas in the circulating mud. The only gas detected was CO_2 while drilling through the mud loss zone at ~1660-1675 m where levels up to 23% by volume were measured by the mudlogging unit. This gas was detected while drilling altered quartzite overlying dark meta-mudstones and may be either geothermal or biological in origin.

ii. Loss Zones

Well B-2 did not encounter the intermediate depth mud loss zones encountered in B-1. The only losses occurred during drilling near TD, where drilling fluids were partially or totally lost to the formation. Table 3 below summarizes the loss zones encountered during drilling.

Table 3: Summary of well B-2 loss zones.

Depth (m CFH)	Losses
1576	Partial Losses
1660-1665	Total Losses, CO_2=20%
1670-1675	Partial Losses, CO_2=23%

CHF = Casing Head Flange

iii. Temperatures During Drilling

Mud in and Mud out temperatures were continuously logged during the drilling of well B-2. Mud out temperatures generally increased steadily with depth from ~15°C near the surface to ~60°C at TD. No downhole temperature measurements were made during drilling.

iv. Cuttings Samples

At the request of Iceland GeoSurvey (ISOR), JRG assisted in selecting cuttings for further analysis at ISOR labs. Samples were collected at 16 depths that the mud log indicated may have hydrothermal alteration mineralogies. These depths (in meters) were:

Table 4: Samples selection.

Depth (m CFH)	Losses
204	Sample 1
300	Sample 2
403	Sample 3
520	Sample 4
610	Sample 5
730	Sample 6
852	Sample 7
945	Sample 8
1061	Sample 9
1170	Sample 10
1270	Sample 11
1375	Sample 12
1481	Sample 13
1559	Sample 14
1620	Sample 15
1682	Sample 16

IV. WELL LOGGING AND TESTING

JRG Energy began completion testing of well B-2 on 29-November-2016, approximately 28 hours after the end of circulation. A dummy tool was run initially to verify the maximum open depth of the well and to verify safe logging conditions. This depth was found to be ~1630 m, indicating ~50 m of fill material had accumulated on bottom. The original test plan, submitted prior to the start of B1 testing and approved by ISOR, was to be used for B2, with changes made to allow for differences in casing depths, loss zones, and TD. Changes in this plan however were made due to the following circumstances at the wellsite:

- The initial JRG program called for injection up to the point of acquiring pressure fall off (PFO) data, however water was shut off immediately after the liner was run. This was done for two reasons: the first is that it is common practice in some geothermal countries, and the second, because water supply was minimal so conservation methods were observed. Static PT runs were then decided to be run first because of these altered circumstances.

- There was no continuous supply of water to the rig as the supply lines were frozen and the pumps were down. Water was trucked in. This meant that the injectivity test had to be modified and shortened to account for the reduced water supply.

- When performing the injectivity run at the lowest injection rate, the well came under pressure before the desired duration was achieved. This immediately proved the well had very low permeability and would not handle the higher injection. This resulted in a single rate injectivity test.

- The WHP gauge, used during the injectivity tests and recorded by the mud loggers, became completely frozen and therefore inoperable.

- Remaining heat up tests were cancelled due to severe weather conditions preventing access to the wellsite.

To compensate for the conditions, a few modifications to the original plan were needed. An initial static pressure-temperature-spinner (PTS) log was completed on slick line with a Kuster Quantum memory logging tool. A 6-hour heat-up run was completed in the afternoon of 29-November-2016. A 24-hour heat up run completed in the morning of 30-November-2016 during which the fill was observed to have shallowed to ~1607 m. The material on bottom may be sloughing native formation, cuttings falling into the hole, settling drilling mud, or a combination of these things. Dynamic PTS logs were completed on 30-November-2016 during injectivity testing consisting of a two flow rate injection test followed by a pressure fall off test during which the Kuster tool was hung ~10 m off bottom at ~1600 m.

An attempt was made on 2-December-2016 to airlift the well with the drill string hung at ~600 m (~200 m below the static water depth) but the well did not flow. This is likely due to a number of factors including: the fact that the total loss zone at ~1660 m was covered with debris/sloughing material, the drill string in this situation could not be taken further into the well to displace fluid[1], and the permeability of the existing wellbore was very poor. Additional well testing was cancelled by the client due to severe winter weather.

A summary of the logging runs is tabulated in Table 5 as well as in Appendix A: Table 7: Well Test Summary.

Table 5: Summary of logging runs.

Date and Time	Type of Survey	Maximum Logging Depth (m CFH)
29 November 2016, 10:00	Initial Static PTS	1607
29 November 2016, 16:00	6-hour Static PTS	1600
30 November 2016, 11:00	24-hour Static PTS	1600
30 November 2016, 13:00	Dynamic PTS-Injectivity Test	1600

i. Temperature and Pressure

After the initial static survey, subsequent static surveys indicated that the maximum temperature of B-2 was ~124°C at ~1600 m. Successive static temperature surveys show a gradual heating of the well, as can be seen on the summary well log in Figure 3. The temperatures were increasing up to the last survey, and may eventually stabilize at ~130-135°C at TD. The temperature profile of well B-2 may eventually be hotter than well N-4 after it fully heats up, as can be seen in the temperature-elevation profiles for wells B-2 and N-4 in Figure 5. Based on the evolution of the temperature in well B-2 between the three static surveys, the well may heat up another ~10°C. This prediction is evident in the Horner plot in Figure 2: Horner Plot of temperatures at depths near the bottom of well B-2.

The temperature gradient in the bottom ~150 m of the well is ~30°C/km and lower than the bottom hole gradient in well B-1 at ~1450 m (~50-100°C/km). The gradient near the bottom of the well is lower than the gradient at more shallow depths, which is ~60°C/km. This falling gradient with depth may be indicative of proximity to a potential isothermal geothermal reservoir, which may have been encountered at the zone of total losses at ~1660 m.

The bottom hole temperature and temperature gradient in B-2 support the existence of the geothermal anomaly at the Karkar Geothermal Field as first identified in well N-4.

The table below summarizes the feed zones encountered during drilling and interpreted from the well testing.

Table 6: Summary of well B-2 feed zones.

Depth (m CFH)	Type of Feed Zone	Temperature (°C)
1576	Partial Losses, fault zone?	125-135(?)

[1] Typical airlifts are performed by taking the working string to at least 33% of total fluid column ((1660m – 400m) * 33% + Fluid lever) ~ 800m CHF. This is the depth of the start of the lifting process. After initial lift is not successful, the working string is continued in the hole until the flowing commences.

1660-1675	Total Losses, fault zone?	130-140(?)

CHF = Casing Head Flange

The maximum static pressures were logged during the third static PTS survey with ~118 bar measured at ~1606 m. This corresponds to a static water level at a depth of ~382 m. The static water levels have progressively shallowed between the static PTS surveys, indicating the well is filling with fluid. This rise in water level is also partially due to the thermal expansion of the water in the wellbore as it heats up.

Note that the static water level in well B-1 was measured at ~113 m. This significant difference between the water levels of the two wells (>250 m) is indicative of very poor hydrological communication between the two wells over the open (uncased) depth interval. This suggests that well B-2 may have crossed a hydrological barrier such as an impermeable strand of the N-S fault zone. It should also be noted that, unlike well B-1, the basement contact in well B-2 does not appear to be permeable.

ii. Permeability

The injection test was carried out on 30 November, as detailed in the Appendix and as shown in Figure 1. A PTS tool was placed at 690 m initially and held until the pumping stabilized. After stabilisation occurred, two passes were performed and the tool was left at TD for the pressure fall-off.

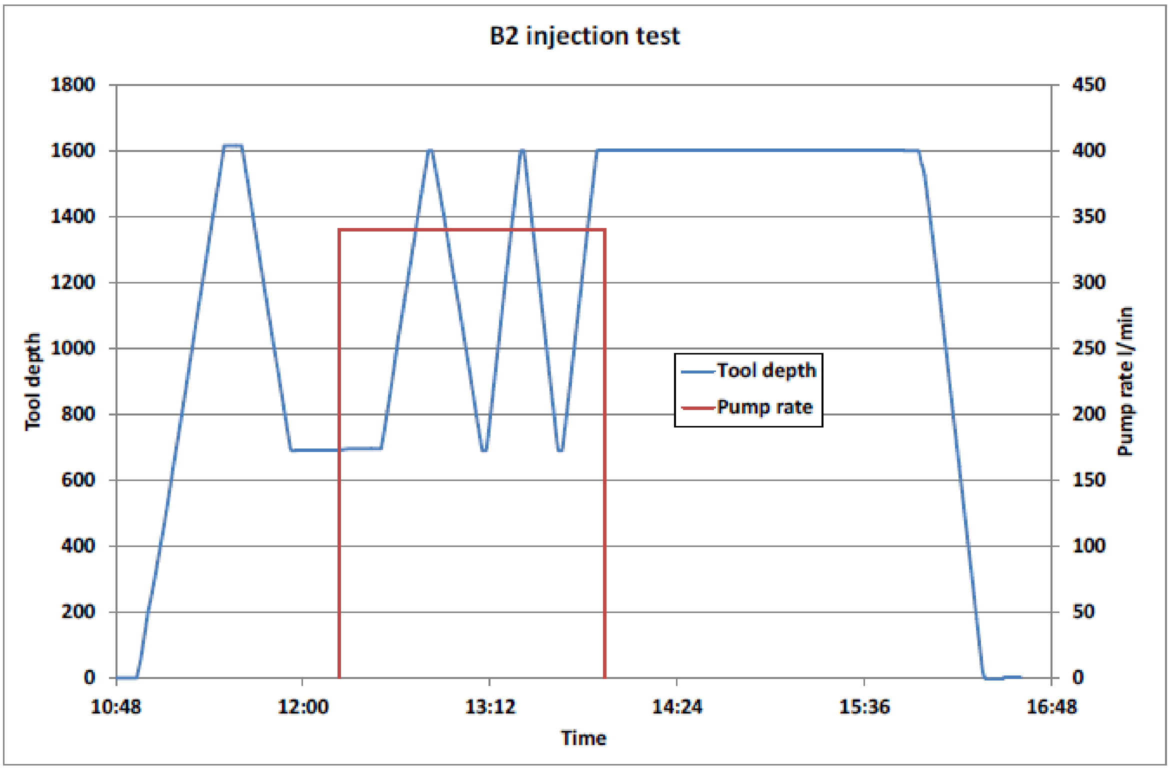

Figure 1: Injection Test

The spinner data was inspected and is of reasonable quality. The frequency logs are shown in Figure 4. There were some intervals of zero data which probably represent missing data and were deleted for error minimization.

The results are shown in Figure 3. A rough injectivity index (II) of ~0.7 tons per hour per bar (tph/bar) was calculated during the multi-rate injection test. This is a very low II, but as stated above, does not represent the permeability likely present below ~1660 m.

Fluid velocity is significantly different from zero only at depths above 800 m, although it is likely that there is flow down to a depth of 900 m. (The shown error bars are one standard deviation, "significant" requires greater than two standard deviations.) The temperatures show relatively little cooling of the open hole. There is some cooling, indicating that there is some flow down all the open interval, but it is relatively small.

Further analysis of the spinner logs and temperature transients allows identification of permeable intervals. There are no significant feed zones recognized in the logs, but a minor feed zone appears to exist at ~1576 m, which correlates with a zone of partial losses. Horner Plot analysis suggests the temperature of this zone is >120°C and may eventually heat up to >130°C (Figure 2). It must be noted that Horner temperature buildups are generally indicative rather than precise, being prone to inaccuracies. They are affected by drilling losses, and so are best in wells of low permeability, as is the case with B2. The plots do generate good straight lines, and indicate final temperatures a few degrees higher than the last log, with a maximum temperature of around 130°C. These plots do confirm that there are no markedly higher reservoir temperatures present near B2.

The bottom of the well below 1576 m appears to be completely impermeable, however, the total losses at ~1660 m likely represented a zone of significant permeability. The temperature of this zone may be >130°C. Unfortunately, this zone could not be tested due to cuttings sloughing into the hole and filling the bottom of the well from 1684 to 1607 m.

There is small but significant flow from the casing shoe down to 800 m. This flow is then largely lost by 900 m, but the noise in the data is too great to specify losses within this interval. It may be that most of the loss is near 800 m, but this is not definite. Below 900 m there is only minor flow, so the zone 800-900 m is identified as the major permeable zone, with only minor permeability elsewhere in the well.

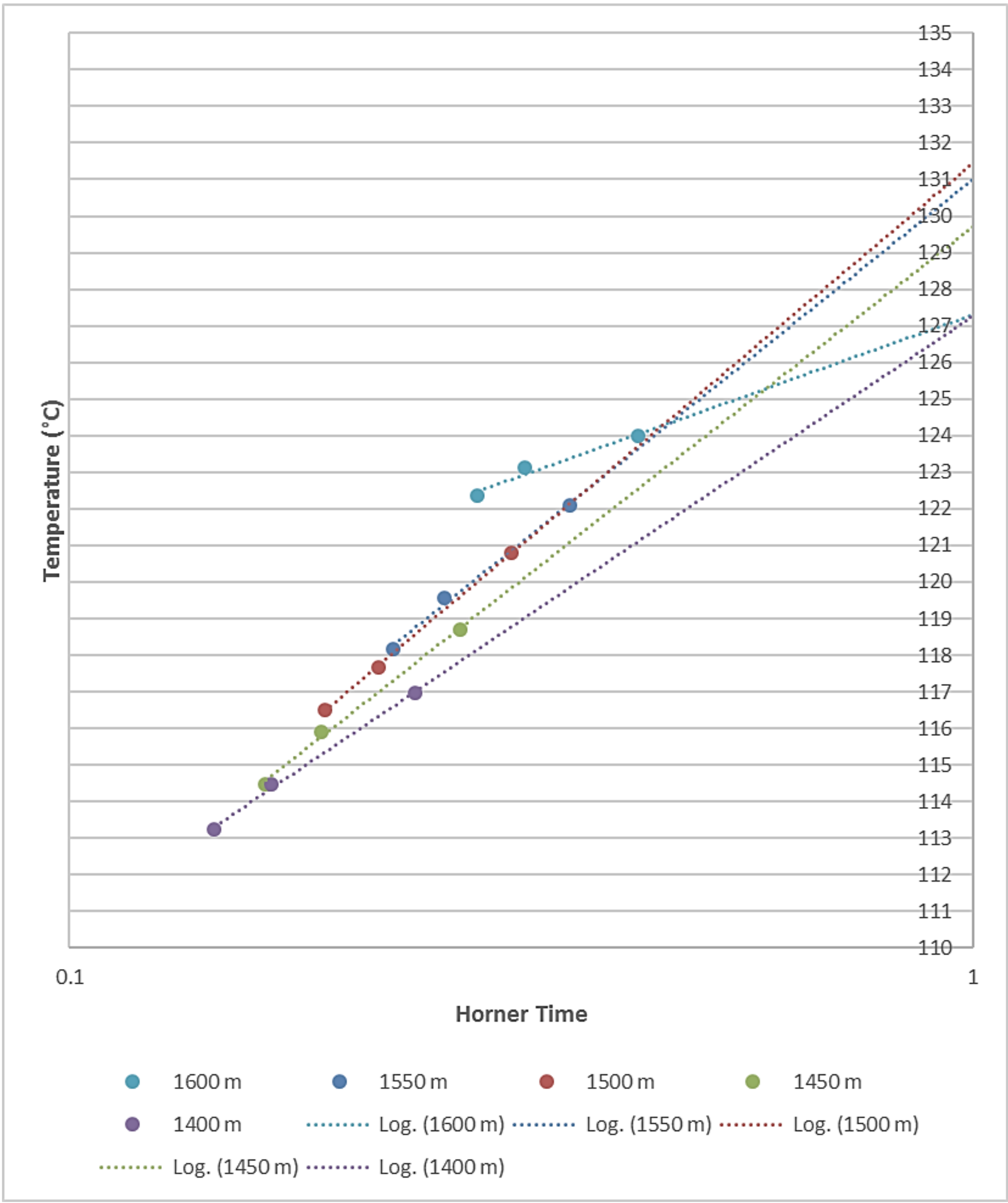

Figure 2: Horner Plot of temperatures at depths near the bottom of well B-2.

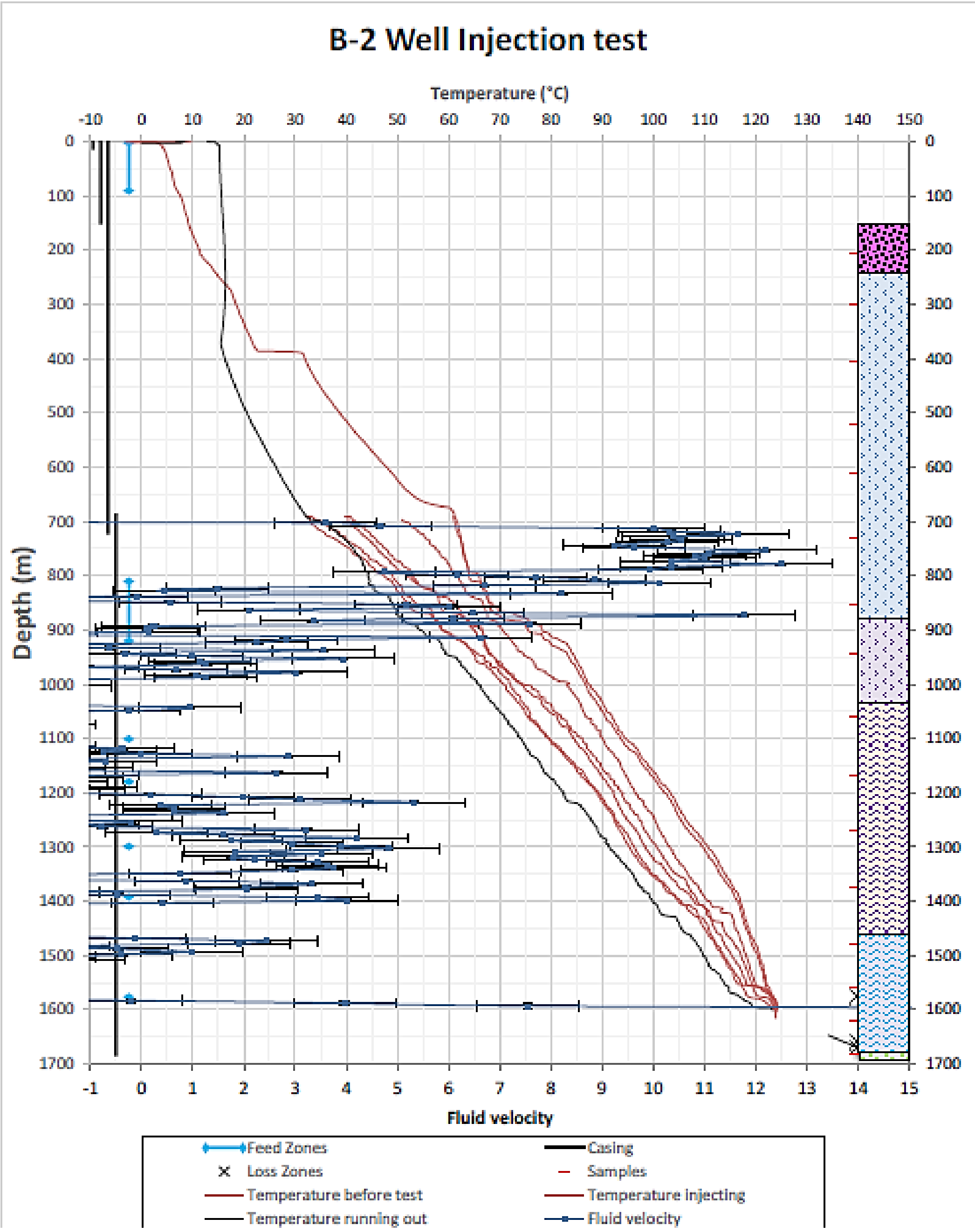

Figure 3: B-2 Injection Test Results

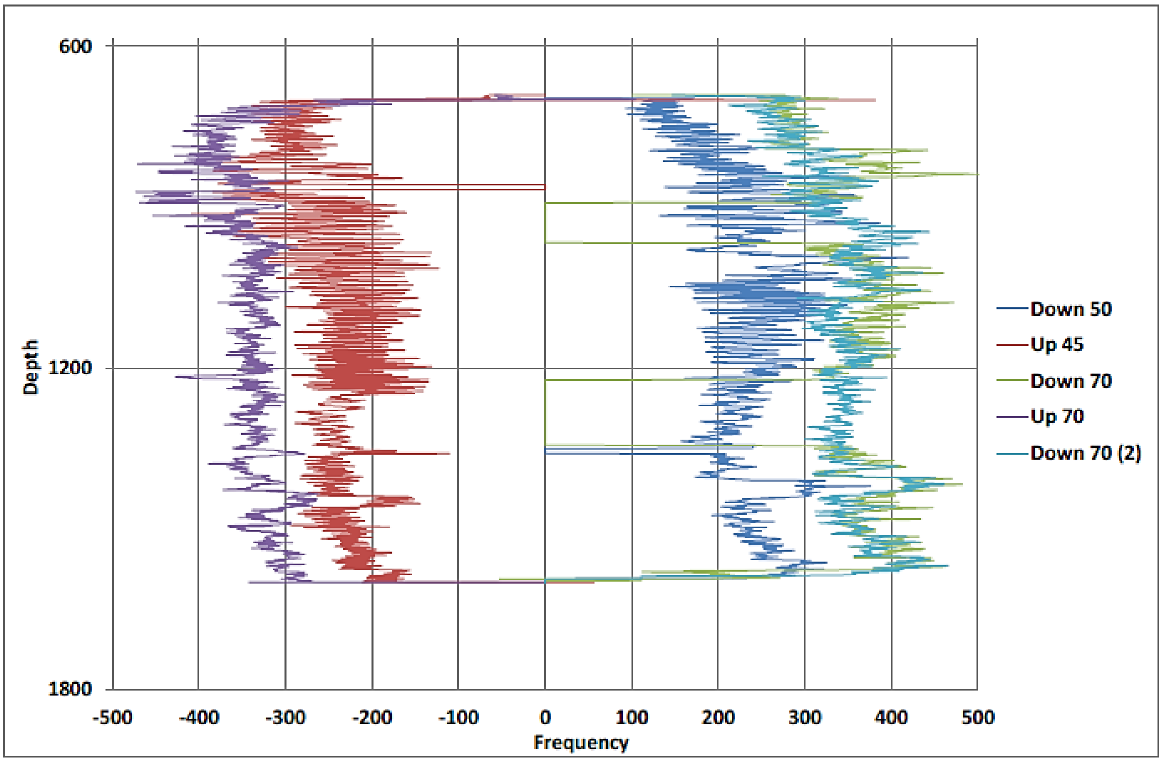

Figure 4: Frequency Data During Injectivity Test

A pressure falloff was conducted after the spinner profiles were obtained. The tool was set stationary at 1600 m while the pumps were shut-off. Figure 4 shows a linear plot and Figure 5 a Horner plot.

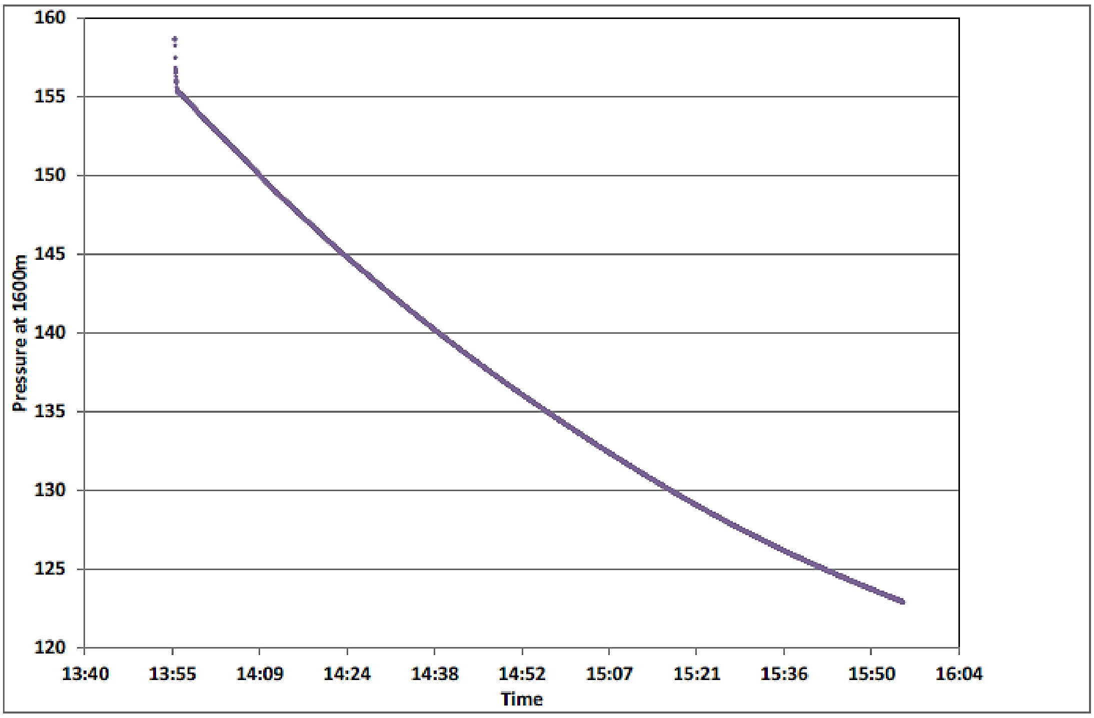

Figure 5: PFO at 1600m_Cartesian Plot

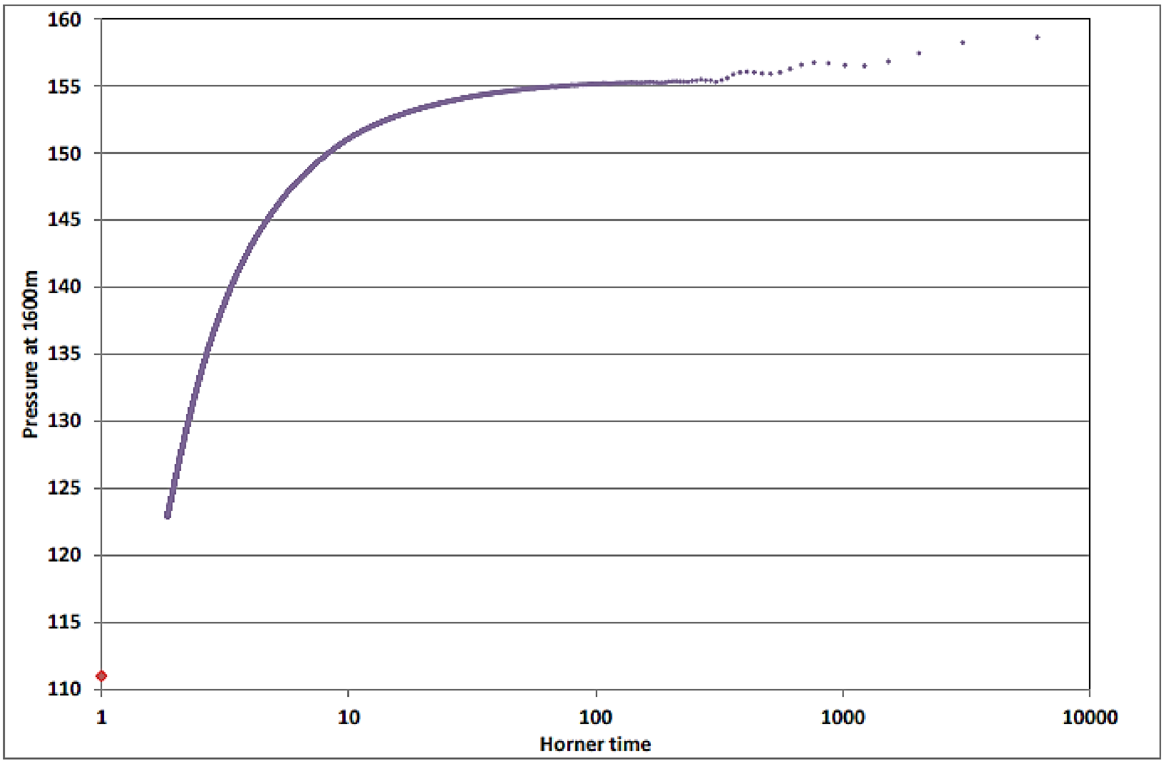

Figure 6: PFO at 1600m_Horner Plot

The red point added to Figure 6 is the pressure from the previous day. Total pressure change to this presumed stable pressure is 47.6 bar, giving an injectivity of 7 lpm/b, or 0.4 t/h/b, very poor permeability. The Horner plot shows no indication of greater permeability at distance.

Figure 11 shows a plot of the data in the two wells. There is a pressure differential between the two wells of over 25 bar, indicating generally poor permeability – if there were some highly permeable structure elsewhere, but not intersected by the wells, it would still tend to equalise pressures across the area. This suggests overall low reservoir permeability between the two wells over the depth interval of the open hole sections, i.e. ~600 to 1700 m depth.

V. UPDATED CONCEPTUAL MODEL

The conceptual model of the Karkar Geothermal Field, originally presented in a resource assessment report by Georisk (2012) and revised by ISOR (2012), has been revised and updated based on review of the available resource reports, original re-interpretation of the data sets, and integration of data acquired from B-1 and B-2. Cross-sections illustrating the conceptual model have been prepared and are presented in Figure 8 and Figure 9. Cross Section AA' runs WSW to ENE approximately perpendicular to the mapped N-S extensional fault zone and includes the Jermaghbyur Hot Spring, well N-4, and the basin containing wells B-1 and B-2. Cross Section BB' runs from NNW to SSE approximately parallel to the mapped N-S extensional fault zone, through the volcanic domes on either side of the basin and wells B-1 and B-2, and approximately perpendicular to the E-W strike slip fault interpreted by Erdogan Olmez (personal communication).

The preferred conceptual model involves a heat source at unknown depth related to volcanic intrusives and/or high regional heat flow. Hot buoyant fluids ascending from depth along the extensional faults utilize permeable marble zones in the basement rocks, fault complexities such as the intersection of the E-W and N-S extensional faults, and fracture networks between the faults to circulate forming a geothermal reservoir at depths of approximately 2000-3000 m and at temperatures between 150-160°C. The intersection of the fault trends allows an upflow of geothermal fluid to reach the permeable contact between the Paleozoic basement rocks and the overlying fractured Quaternary volcanic rocks. Geothermal fluid outflows along the basement contact in all directions at temperatures less than 100°C and mixes with cold meteoric groundwater which downflows along the fractured throats of the volcanic domes and within the fractured basin.

Meteoric water within the pull-apart basin recharges the reservoir along extensional faults on the margins of the basin.

An outflow at >30°C flows west along the basement contact and surfaces along a minor N-S fault at the Jermaghybur Hot Spring, along with CO_2 derived from buried organic and/or deep crustal sources.

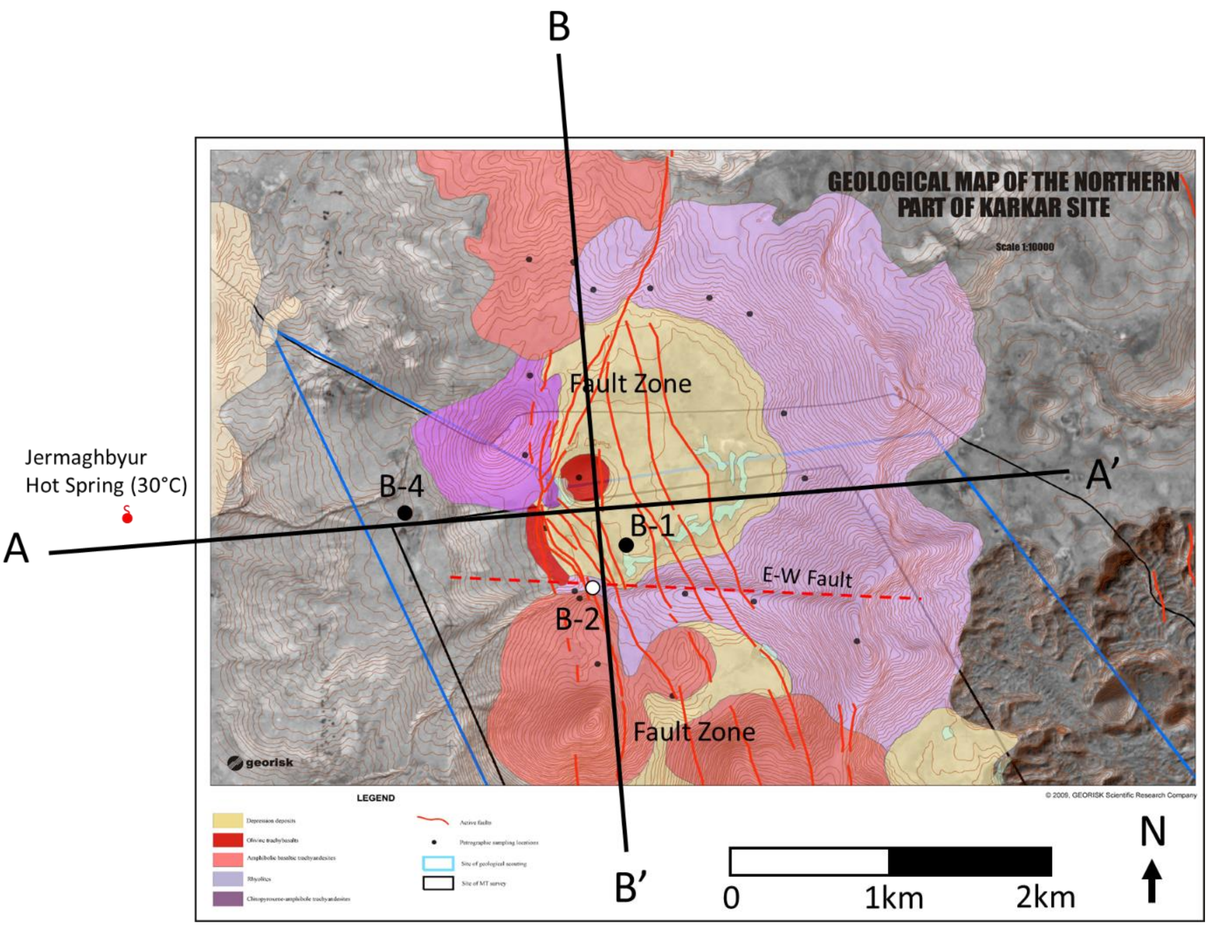

Figure 7: Map of the Karkar Geothermal Field. Base geology map is after Georisk (2009).

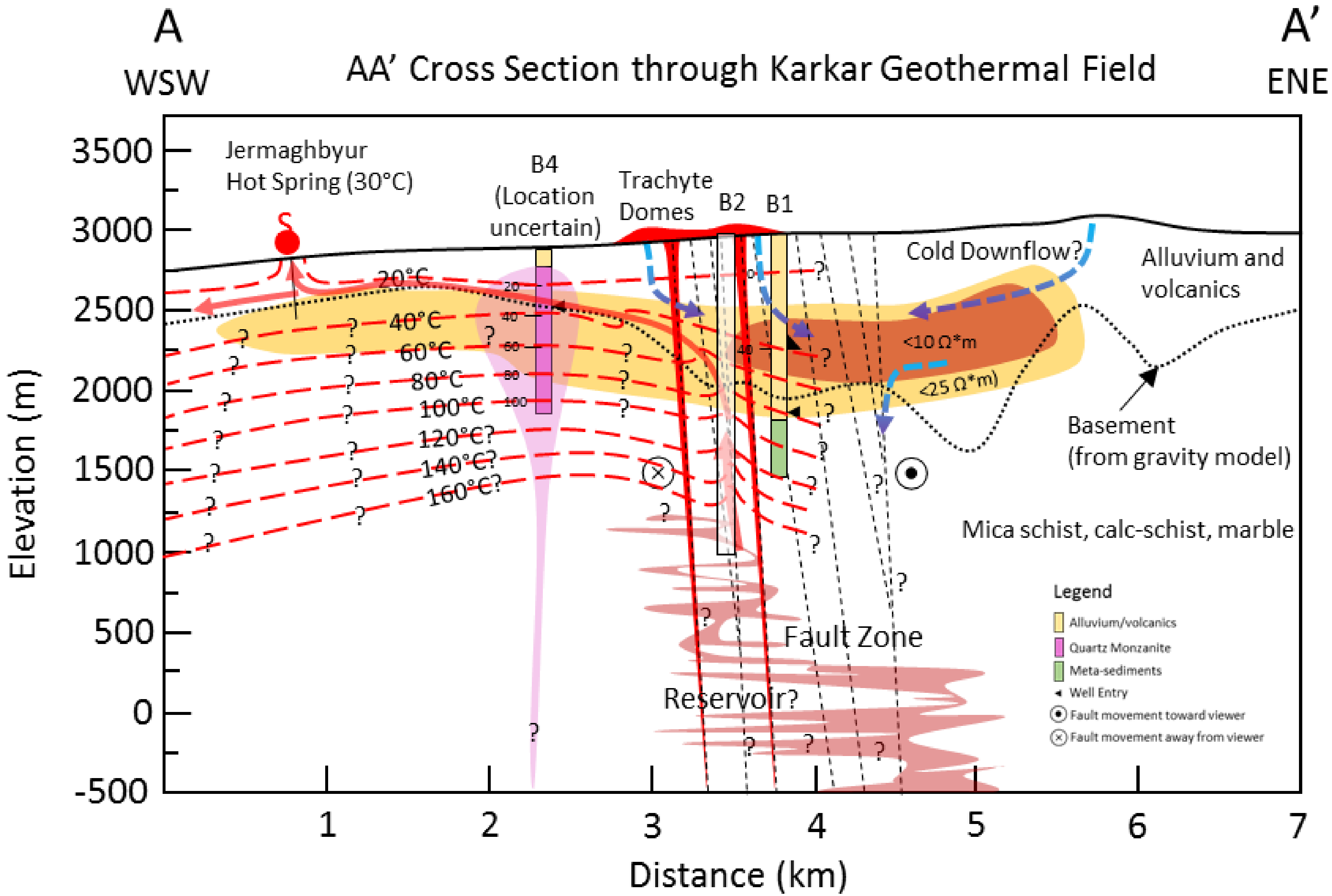

Figure 8: Cross Section AA' illustrating the conceptual model of the Karkar geothermal Field.

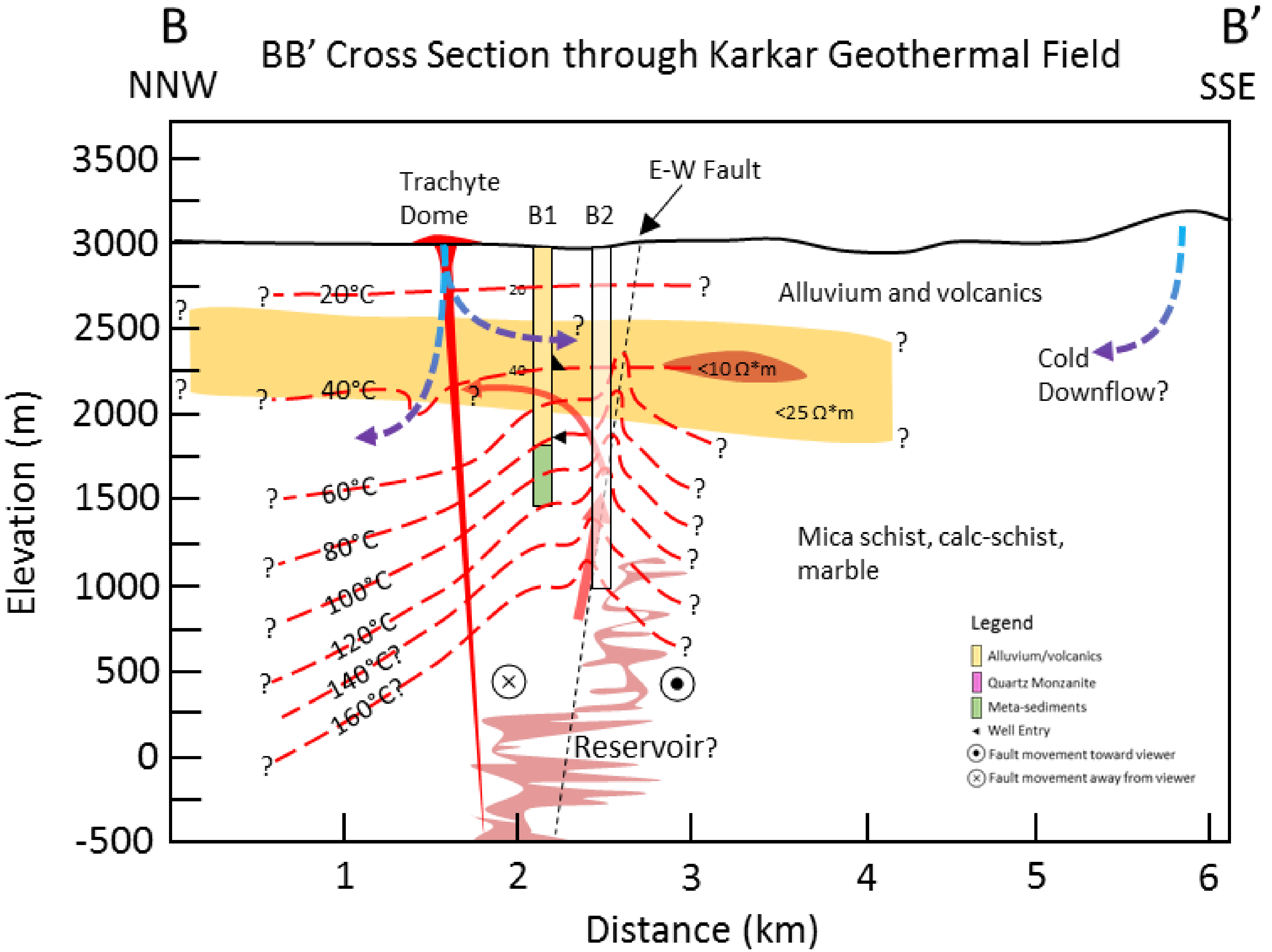

Figure 9: Cross Section BB' illustrating the conceptual model of the Karkar geothermal Field.

VI. CONCLUSIONS

Data from well B-2 supports the high temperature gradients and elevated temperatures of the Karkar Geothermal Field first discovered in well N-4. While the precise location of N-4 is unconfirmed (to within several hundred meters), well B-2 extends the area of this heat anomaly south into the pull-apart basin. The elevated conductive gradient at the bottom of B-2 has proven temperatures >120°C at less than 2000 m, and possibly as high as 160°C at depths of 2000 m if the temperature gradient from depths of 1600 to 2000 m is higher than observed at the bottom of well B-2. By analogy to commercial geothermal fields in similar basement rocks in western Anatolia, temperature gradients could decrease near intermediate aquifers and then increase again with greater depth[2]. Therefore deeper drilling could possibly encounter commercial permeability and temperatures at depths up to 3500 m.

The following other conclusions also apply:

- No significant feed zones were able to be tested in well B-2. A zone of total lost circulation was encountered at ~1660 m but was covered in sloughing cuttings before it could be tested. If this zone could be tested it may have a temperature >130°C.
- If B-2 is deepened to 2000-3000 m it may encounter permeable zones at higher temperature within the basement rocks. This situation would be analogous to commercial geothermal fields in western Anatolia and in the western United States.
- Unlike well B-1, the basement contact in well B-2 is not permeable.
- As evidenced by the large difference in static water levels between wells B-1 and B-2, the two wells are not in good hydraulic communication. This may be due to B-2 crossing a hydrological barrier such as impermeable fault.
- The lateral extent of the Karkar Geothermal Field is unbounded in all directions. Deep temperatures in the basement rocks may fall of rapidly to the east of well B-1. B-2 may be the hottest well in the field after it fully heats up, but the upflow may also be located elsewhere.

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[2] example of published data from an operating field at Gumuskoy in Turkey (http://pubs.geothermal-library.org/lib/grc/1028705.pdf) Even less temperature than the Karkar wells, Well ORT-4 reached a max temp of 130C at 2350 m. Elsewhere in the field you can get much better wells e.g. well GK-1 drilled to 2100 m and is 178°C and flows 230 tph. Interestingly, the two wells have an 18 bar static pressure difference between the two wells because they are in different aquifers. After acidization, ORT-4 produced 126 tph.

In the Basin and Range in Nevada, there's Patua, which is is operating at up to 25 MW. It has similar temperature profiles to Karkar at similar depths. https://www.geothermal-energy.org/pdf/IGAstandard/WGC/2015/22042.pdf

i. Recommendations

Further wells should be drilled to at least 2000 m at Karkar in order to prove higher temperatures and permeability associated with a possible upflow at the intersection of the dominant fault trends. Alternately, wells B-1 and B-2 could be deepened.

The following other recommendations also apply:

- Cuttings from B-1 and B-2 should be analysed at an appropriate laboratory for petrographic mineral identification, alteration clays by shortwave infrared (SWIR) and/or x-ray diffraction (XRD), and possibly fluid inclusion temperature analysis. Appropriate laboratories include ISOR in Iceland and GNS Science in New Zealand. The data and conclusions from these analysis should be made available to technical overseers and included in the conceptual models.
- Temperatures in B-1 and B-2 should be re-surveyed at a later date to evaluate the stabilized temperature and confirm temperature gradients. This would help minimize the introduced error in the horner temperature plot and lead to higher accuracy in the conceptual model.
- Well B-2 should have the cuttings on bottom cleaned out with a rig or coiled tubing unit and air compressor/Nitrogen unit. The total loss zone at ~1660 m should be tested once this is complete. Both well intervention methods are capable of clearing the cuttings from the bottom of the well, however the best course of action for this particular case is a drilling rig. The main advantage of using a rig in this instance is that the existing lining can be pulled and drilling may continue. If this course is chosen, the initial planned TD of 2000 m should be targeted to provide more conclusive data of existing models and improve the likelihood of viable production. The size and capabilities of the unit should be larger than that used to drill B1 and B2.
- An area thermography map should be created to re-evaluate existing surface geothermal features and identify the location of the N4 wellbore. Consider using ROAV's or drone capabilities with radiometric IR cameras to complete this task in a cost effective manner. The results can be used to improve the accuracy of the existing conceptual model and improve the accuracy of subsequent well placements.

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APPENDIX A: Test Summary

Table 7: Well Test Summary

Time Start	Time Stop	Comment
28 Nov		
1600	18:20	Well was completed and liner run. The water was turned off at 0600. Issues with getting HD winch running and having to get measurements valve off B1 meant the drift run was only started at 1600. The drift was run and tagged fill at 1630m – 30m above the TLC zone encountered when drilling. No further runs were undertaken that day due to night time approaching and the slippery conditions on the site and the rig.
29 Nov		
0900	1130	Conduct shut PT run #1. Well had been shut for 28 hours.
1500	1630	Conduct shut PT run #2
30 Nov		
0900	1700	Conduct Static PTS followed by injectivity and PFO
1055	1129	Shut PTS (zero flow into well). Tool tagged at 1607m -bottom hole temp 124 degC
1136	1155	Pull up to 690m
1214		Pumps turned on to minimum flow rate – average flow over duration of injectivity was 340 l/min
1230	1248	Pump rate 360 l/min. RIH 690 – 1600m at 50m/min
1249	1308	Pump rate 330 l/min. POOH 1600 -690m at 50m/min
1310	1324	Pump rate 320 l/min. RIH 690 -1600m at 70m/min
1325	1338	POOH 1600 – 690m at 70m/min. Some water coming out of stuffing box gland at end of run.
1340	1353	Pump rate 315 l/min, casing head pressure 0.5b (water coming out of stuffing box gland). RIH - 690 – 1600m at 70m/min
1356	1556	Pumps turned off – second injection rate called off due to pressurised wellhead. Also, whp could not be measured as pressure lines to mud logger shed were frozen.
1556	1622	POOH – 1600m to surface at 50m/min
1622	1715	Rig down wireline gear and prepare for air lift.
1715	2200	Download and process data

APPENDIX B: Summary Plot

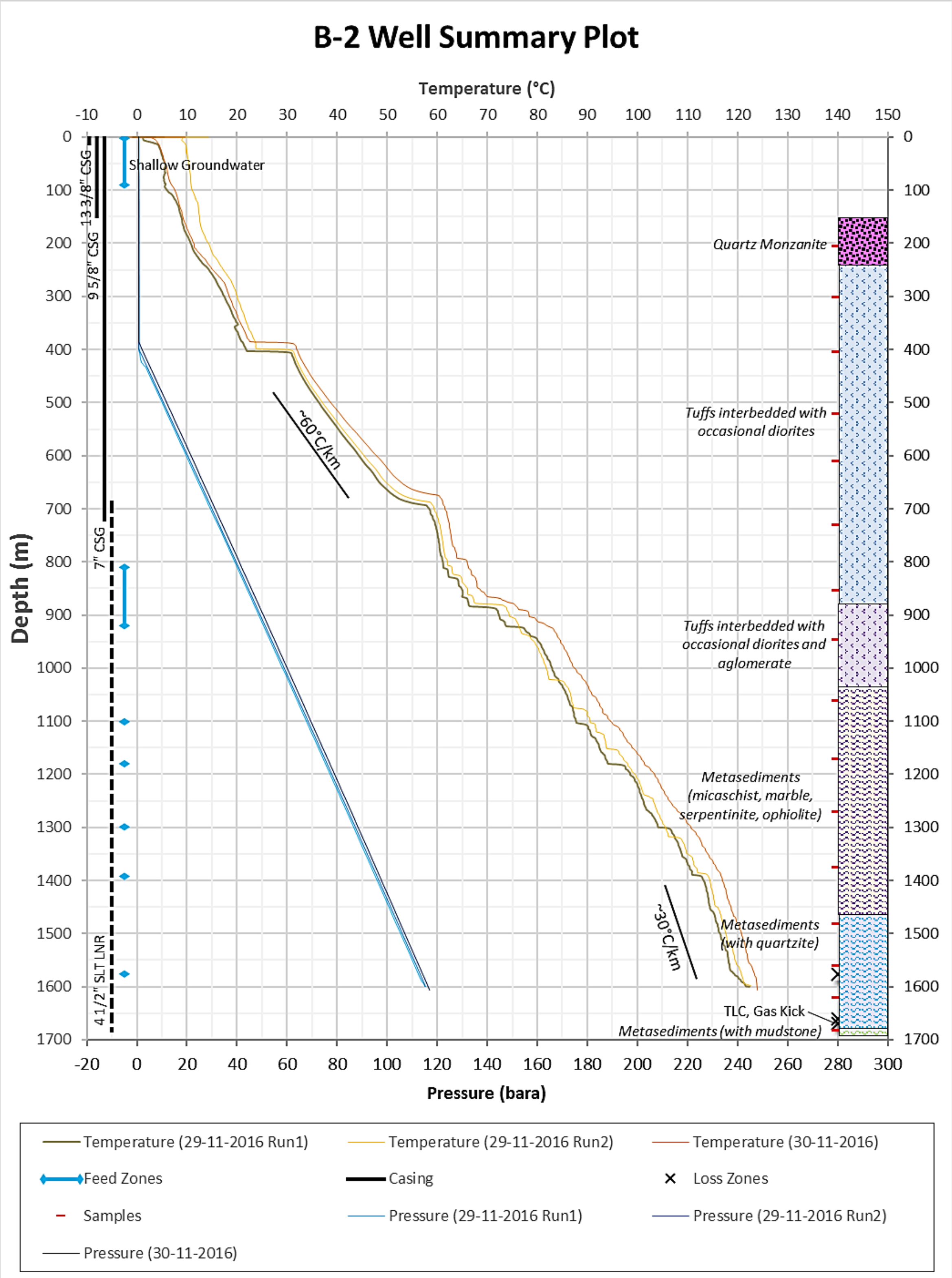


Figure 10: B-2 Summary Plot

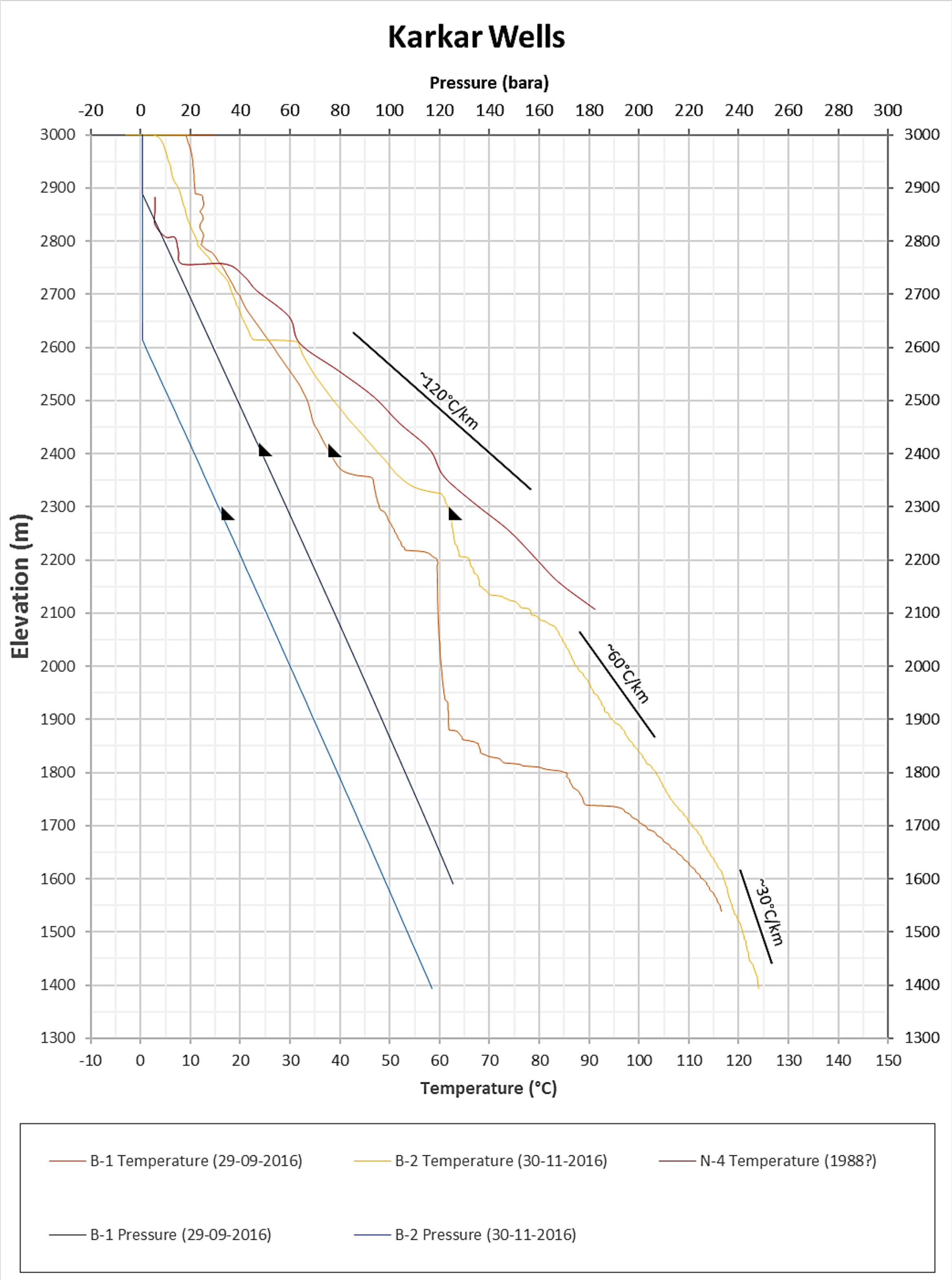


Figure 11: Temperature and Pressure vs Elevation profiles of the three Karkar wells.

APPENDIX C: Acknowledgements

There were many different companies that helped with the completion of this project and analysis of the data. We would like to acknowledge the following people and their respective companies:

Malcolm A. Grant
Director/Senior Geothermal Reservoir Engineer
MAGAK

Maxwell Wilmarth
Senior Project Geologist
Geologica Geothermal Group, Inc

Andrew Austin
Senior Geothermal Well Test Engineer
JRG Energy Consultants Ltd.

Dr. Mert Eker
Operational Manager
HD Energy Limited

APPENDIX D: Comments and Responses

JRG Energy fully supports the claims and assumptions made in this report, and will openly accept any comments or questions related to the subject matter. The following is reply to JRG Energy's B2 Welltest Report_Rev1 from ISOR made January 18, 2017 and then discussed with JRG Energy personnel January 24, 2017.

Comments by ISOR on the report from JRG Energy on "Well Logging and Well Test Results for Slim Well: Karkar B2" from January 18, 2017.

ISOR has reviewed the report by JRG Energy which presents information and work done on the geology and geophysical information on well B2. The report describes a slightly revised conceptual model for the Karkar area. It seems that there is not much new to be learned from well B2 to support the conceptual model that JRG presented last time, in the B1 report and updated this time. ISOR has commented on this project earlier and provided WB with comments on the same subject. First with a memorandum from September 29, 2016 and then through e-mail, sent on October 27, 2016 (attached below). These comments are much in line with earlier observations.

The results are basically the same as in B1 and if anything, B2 shows even lower geothermal gradient than B1. Temperatures are similar, formations as well and very little permeability is encountered. The only thing that seems to be the basis for the suggestions for high temperature resource at deeper levels (as presented in the conceptual model) is the geothermal gradient which in this case seems to be extended linearly. Results from X-ray diffraction clay-analysis of samples selected from well B-1 show that significant hydrothermal alteration is not noted.

Using geothermal gradient is a good tool to identify if there is any local elevation/anomalies in formation temperatures from the normal continental gradient. This should, however, not be extended to great depths, expecting that it will be linear. As soon as the top of a convective, permeable reservoir is reached, only a small change in temperature should be expected over several hundreds of meters.

Extending the geothermal gradient can be misleading and a suggestion of high temperature reservoir needs to be based on more than just the gradient. In the temperature profiles in B2 (actually also in B1) an apparent "bend off" at the bottom, indicates significant changes in the gradient (lowering). This is possibly due to convection of 130-135°C water close to the bottom of the well (maybe from a fracture, hit at 1660 m). Having good permeability and convection, the temperature may change very little with depth over hundreds of meters, as mentioned before. Since the gradient information for each well is not exactly the same, extending each one would give different results for temperatures at specific depths. This is actually highlighted in figure 10 in the JRG report (see figure below). It should also be noted that at the bottom of wells B1 and B2 the temperature profiles seem to be looking very similar in terms of gradient, which does not seem to be considerably high.

All of the information collected so far is still indicating intermediate temperatures, which in itself can be a viable resource. But that needs considerable permeability, which the data does not yet indicate, unfortunately. The very low permeability is also discussed in the report, where only 0.2 L/S/bar is encountered. The only positive indication of higher permeability was the circulation loss encountered at 1660 meters, which remains to be tested.

It could be worthwhile to look into cleaning out the liner in well B2, as has been discussed before, and even pull it out if possible, in the hope that the debris in the well can be cleaned out, giving access to the possible permeability encountered during drilling. This may be done either using the present rig, using slim drill pipes, or hire a Coil Tube Unit (CTU) to clean out the liner. If the liner can be removed, the well should be deepened to accommodate any debris accumulating at the bottom.

It is common practice to drill at least 50-100 m deeper than the deepest circulation loss, to make room for any debris and cave-ins that may otherwise collect at the bottom and block the permeable zone (as is probably the case in well B2). Due to circumstances described in the report that seemed not possible.

It is not guaranteed that such a task will be successful, especially if the liner cannot be removed, but if the cleaning is successful, it would present an oportunity to test the well, both for injectivity and productivity as well as being able to sample the brine for chemical analysis and get information on “reservoir” temperatures of the brine.

This task will be challenging and will most likely cost hundreds of thousands of dollars, but it will be less expensive than drilling a new well, which we see very weak justification for. The big question is if there is any reason to proceed with this project, unless there is some possibility of utilising these intermediate temperatures with limited permeability in a feasible way.

Memorandum from September 29, 2016.

Memorandum regarding findings in well B1 and drilling of well B2 in Karkar, Armenia.

Iceland GeoSurvey (ISOR) has been following the drilling in Karkar, Armenia over the last couple of months as a consultant to World Bank.
Before it was decided to drill in the area, ISOR expressed the opinion that that it was not likely that a high temperature geothermal resources would exist at Karkar but it seemed likely that the Karkar depression could host a low or even intermediate temperature geothermal system.
. Therefore it could be of value to drill a slim exploration well to test the temperature at depth and check the nature of the low resistivity (if it is due to hydrothermal alteration), seen between roughly 500-1000 meters depth. The first well was to be drilled into the apparent faults in the western part of the small depression and was supposed to target those faults between 1200-1500 meters depth. The second well was to be drilled in the eastern part of the depression, close to where the lowest resistivity was found. During preparations, the well sites were changed due to inaccessibility.
The initial idea was that one well should be drilled with the option of drilling a second well if the first would not provide sufficiently conclusive information.

At this stage, well B1 has been finished down to 1500 meters and the main results are as follows:

1. The low resistivity at 500-1000 m is not due to hydrothermal activity, but may be a combination of volcanic tuffs and warm groundwater (possibly evaporates present according to earlier mud logging). Horner plot modelling of thermal recovery (770 m depth) indicates formation temperatures of around 50-60°C in this section.
2. At about 1100 meters, the well entered into basement rocks. This consists of some granite, but mainly of metamorphic rocks like marble and schist. In that formation, the geothermal gradient is higher (~100°C/km) than in the tuff formations (Well B1 shows about 120°C at 1461 m-see figure below). This may be due to more active heat mining in the water bearing tuffs than in the tight basement rocks. This is similar to the temperature conditions in the old well (B4) drilled outside the depression. As far as we know, no permeability was encountered in that well which encountered mainly basement rocks.

After looking through the data, we find it unlikely that the formation temperatures are significantly different at similar depths within the depression than we are seeing in the well B1 already. The absence of any geothermal indications at the surface, such as manifestations (fumaroles, altered grounds), elevated gas flux or high soil temperatures is of concern. It is however not unheard of that hidden geothermal systems can exist in areas where surface activity is absent.

The relatively high geothermal gradient (compared to continental crust) shows that there is a heat source somewhere close to Karkar or at depth. What this heat source may be is not clear, but cooling plutonic rocks may be the cause. Rhyolite, basaltic andesite and dacite lavas (~5000 years old) at the surface a few kilometres away may suggest this. At this stage it is not clear where this heat source could be or at what depth.
Using geothermal gradient information is of great value, but one should be careful when extrapolating this information to great depths.

There may be changing permeability within the depression, especially as secondary permeability (faults and fractures). So if the temperatures found are acceptable (low, intermediate or high) it could be viable to try to find better permeability in the area by drilling.

In general, permeability is low in metamorphic basement rocks. There are, however, examples of such rocks hosting a reservoir through intense fracturing of the basement rocks and with very high temperatures carbonate rocks may start breaking down, increasing permeability.

It is clear that the temperature gradient in the Karkar area is considerably higher than in a normal continental crust (~30°C/km) and that gives some hope that there may exist an exploitable geothermal resource/reservoir, not necessarily a high temperature reservoir with high flowrates, but maybe low to intermediate temperatures with low to intermediate flowrates.

On September 29th ISOR received a letter from the TSSC team to the R2E2 Fund regarding justification and recommendations of drilling the second well at Karkar area. In that letter the TSSC group suggests to drill well B2. ISOR is not necessarily in agreement with the conclusions made in the letter, but in this case, ISOR agrees that it would be beneficial to drill another well (especially since a rig is in the area and material already procured) as deep as the drilling contractor is comfortable with, aimed to maximise the chances of good flowrates from faults and fractures in the basement rocks. This would not only evaluate the actual temperature of the liquid in these faults and fractures but also test the connectivity to a possible, highly fractured reservoir that may be present in basement rocks like marble and schist. For that purpose, a well site close to what is suggested at this moment some 400 meters S-W of well B1, where possible intersection of faults occur, is acceptable.

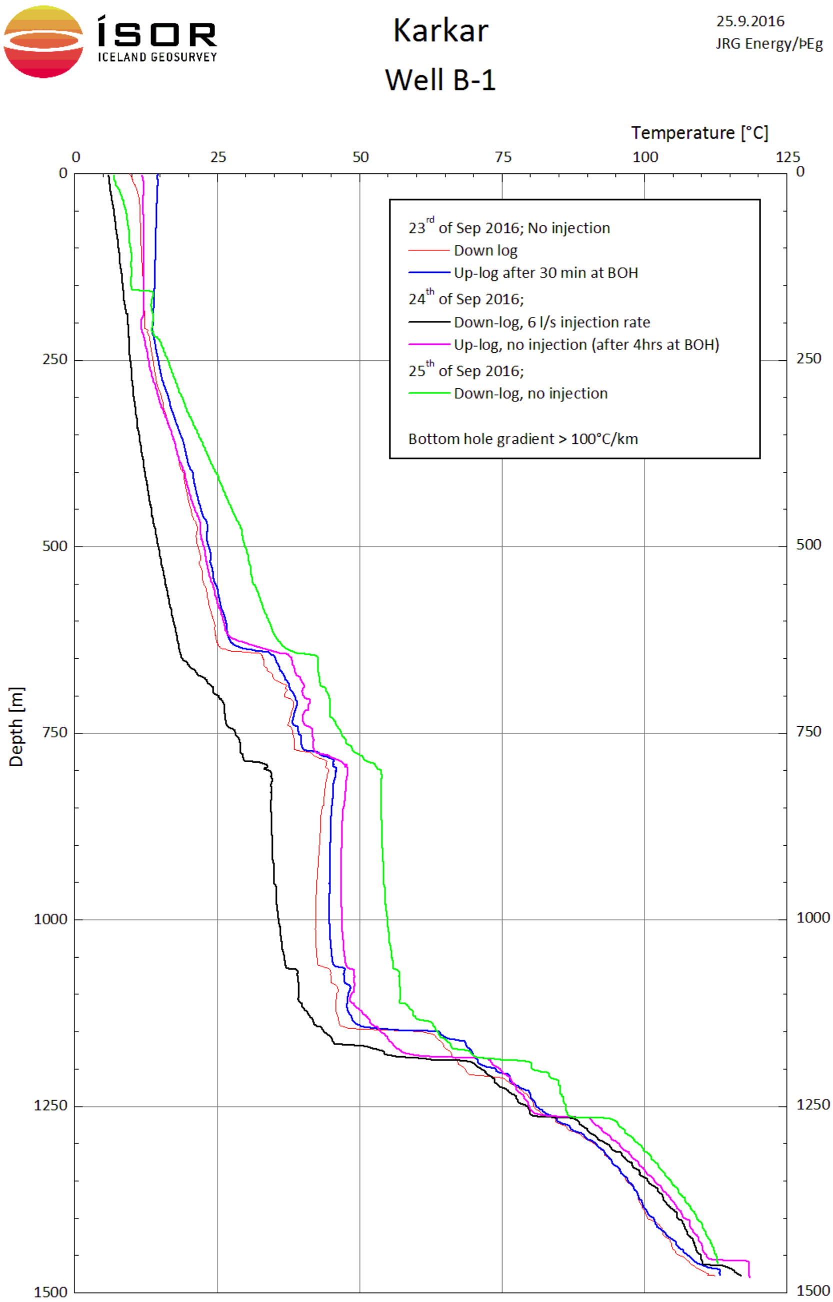
Bjarni Richter

Benedikt Steingrímsson

Knútur Árnason

Þorsteinn Egilson

Sigurður Sveinn Jónsson



ÍSOR
ICELAND GEOSURVEY
Karkar
Well B-1
25.9.2016
JRG Energy/ÞEg
Temperature [°C]
0
25
50
75
100
125
Depth [m]
0
250
500
750
1000
1250
1500
23rd of Sep 2016; No injection
Down log
Up-log after 30 min at BOH
24th of Sep 2016;
Down-log, 6 l/s injection rate
Up-log, no injection (after 4hrs at BOH)
25th of Sep 2016;
Down-log, no injection
Bottom hole gradient > 100°C/km

E-mail sent to Mr. Thrainn Fridriksson on October 2016.

ÍSOR received the logging and well testing report from JRG Energy. After reading through the report, ISOR found that there are some discrepancies in some of the tables and text regarding the circulation losses and the formations recognized. Also there is a suggestion that the very low resistivity in the tuffs could be somewhat due to an older hydrothermal alteration, even though no indications are apparent in the cuttings on this alteration. In general there are also minor issues regarding the reporting and interpretation of the permeability and temperatures in well B1.

Information on the bottom hole temperature, geothermal gradient, very low permeability and the occurrence of metamorphic rocks seems to be solid.

The geothermal gradient in well B1 is high (that is after entering the metamorphic rocks), compared to the average continental geothermal gradient, or roughly 3 times higher. This is an indication of high heat flow, possibly related to volcanic activity or radioactivity of decaying plutonic rocks like granite. This may be the source of heat for a geothermal system.

Care should, however, be taken when extending a geothermal gradient to great depths, since it is usually not certain that it will extend unchanged.

1. If a reservoir (permeability) is reached, the gradient will most likely change due to convection and a uniform temperature is expected over hundreds of meters. This might happen within the next few hundred meters of drilling within in a reservoir with low to intermediate temperatures or if it is encountered deeper than that, may reach a reservoir with higher temperature.
2. If the gradient will stay roughly the same to greater depths, it might indicate that little or no permeability can be expected. Permeability will disrupt the gradient. In this case the high temperatures may be reached but no reservoir. This may then be a candidate for Hot Dry Rock (HDR) development. In general metamorphic rocks are impermeable, but analogues can be found around the world that they may host geothermal reservoirs, especially in carbonate rocks.
3. The high geothermal gradient observed just below the contact between the volcanic tuffs and the metamorphic rocks may be overestimated and can “bend off” at deeper levels (indications of this can be seen in the temperature profiles, below 1250m). This can be due to the formations at about 1250 m have not fully thermally recovered while they have deeper (giving a flatter temperature profile). This may also be due to heat mining form the basement just below the somewhat permeable tuffs so the temperature of the metamorphic rocks rises faster with depth in top of the basement than at deeper levels.

The high gradient indicates possibilities of the existence of a geothermal reservoir in Karkar Unfortunately we have no solid proof of permeability at depth creating such reservoir. This dampens somewhat the hope that an exploitable geothermal system is present, at least for the intermediate to high temperature. The only surface manifestation, the Jermaghbyur Hot Spring some 2-3 km away, is not very conclusive and indicates reservoir temperatures in the region of 70-

180°C (Georisk, 2012).

The conceptual model presented in the report is optimistic but does not seem impossible even though there is lack of indicative data, except for elevated geothermal gradient. A crucial point in this model is the interpretation of the low resistivity layer as a slightly hydrothermally altered layer. The cutting analysis did not confirm this, but additional XRD may clarify this point. If no trace of hydrothermal alteration is found the conceptual model has to be revised.

Drilling of well B2 will test the conceptual model since it is aimed at the proposed up flow within faults and fractures. Therefore drilling as deep as possible is important (2000 m).

Hopefully the drilling of well B2 will give us some more indications on the situation and we sincerely hope that it will strengthen the likelihood of a commercially viable reservoir in Karkar.

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