FINAL PROGRESS REPORT

PROJECT TITLE: Fairbanks Geothermal Energy Project

AWARD NUMBER: **DE-EE0003219**

CONTACT(S): Principal Investigator

Project Lead
Bernie Karl, Chena Hot Springs Resort
Cell 907-378-2967; recycle@polarnet.com

ACKNOWLEDGEMENT: This report is based upon work supported by the U.S. Department of Energy under award number DE-EE0003219.

DISCLAIMER: Any findings, opinions, and conclusion or recommendations expressed in this report are those of Chena Hot Springs Resort and do not necessarily reflect the views of the U.S. Department of Energy.

PROJECT OBJECTIVE:

The primary objective for the Fairbanks Geothermal Energy Project is to provide another source of base-load renewable energy in the Fairbanks North Star Borough (FNSB). To accomplish this, Chena Hot Springs Resort (Chena) drilled a re-injection well to 2700 feet and a production well to 2500 feet. The re-injection well allows a greater flow of water to directly replace the water removed from the warmest fractures in the geothermal reservoir. The new production will provide access to warmer temperature water in greater quantities.

In 2009, the EPA classified Fairbanks as non-attainment for PM 2.5 and much of the local power is generated by diesel and coal, which are known emitters of PM 2.5. Base-load geothermal energy will offset fossil fuel usage and will therefore lead to a decrease in PM 2.5 and green house gas emissions.

This project will also allow Chena to develop a better understanding of the geothermal reservoir that has been providing 160°F water that is used for electrical and space heating

needs. Previous reservoir modeling has indicated that the reservoir could produce higher temperature water that would allow for an increase in electricity generation.

This project will also provide valuable information that will be relevant to other geothermal hot springs that are located throughout interior Alaska. Successfully developing geothermal power will increase interest in other geothermal areas located in or near the FNSB that can use the work performed by Chena as a model in developing geothermal electricity and space heating.

Executive Summary

In 2006 Chena installed the lowest temperature geothermal power plant in the world that generated electricity using 160°F water produced from the ground as the energy source. Currently the resort still relies on diesel generators to maintain the grid frequency and because the geothermal capacity is unable to meet the resort's electric demand. The three production wells, well 7, well TG-8, and well TG-12 producing 157°F, 163°F, and 163°F temperatures respectively, are located on the west end of the property. The organic Rankine cycle (ORC) geothermal power plant utilizes the refrigerant R-134a as the working fluid to transfer the energy into work by means of turbines. The geothermal water exiting the power plant is then re-injected into the ground at well 1 and well TG-7, with depths of 180 feet and 702 feet respectively, are located on the east end of the field.

A report, included as Attachment 1, titled "Chena Hot Springs Data Collection Project May – August 2009", prepared by Dr. Joanna Mongrain, suggests a deeper re-injection well will extend the life of the geothermal field and produce better results in reheating the re-injected water. Previous reservoir modeling also indicates that the reservoir is capable of producing > 180°F water by means of drilling a deeper well that could reach warmer fractures. Using this information Chena decided to deepen two wells, one a re-injection well and the other a production well, to increase the heat recovery of the geothermal field.

Chena decided to deepen existing well #2 from 800 feet to 2700 feet. Well #2 was chosen because it is located at the east end of the field where all the re-injecting has previously been taking place, and because a drill rig can be set up with minimal site work.

Chena selected Arctic Drilling to complete the drilling because of their familiarity with the sub-terrain at Chena, and they are the only known drilling company within the Fairbanks region that has any experience with geothermal wells. Drilling on Well #2 was originally performed using a try-cone bit that resulted in slow progress, at times only achieving 1 ft/hr. Arctic Drilling then switched to a water hammer with a button bit and was able to increase their progress to 20 ft/hr. Despite encountering large formations and difficulties in bringing the cuttings up, the project didn't use drilling mud due to the risk of plugging up the formations.

Drilling for the re-injection was completed to 2700 feet and the casing has been cemented in. There is 16-inch casing down to 50 feet, 12-inch casing to 500 feet, an 8-inch casing reaching 880 feet, and an 8-inch perforated liner is placed from 880 feet to 2700 feet. A detailed well illustration is provided in Attachment 2.

A static temperature log was taken after the well was completed and the temperature of the well increased from 125°F to 173°F. Figure 1 shows the temperature profile of well #2. At approximately 2200 feet, the temperature in well #2 has a dramatic increase of about 30°F then resumes a linear relationship to the depth reaching the highest temperature at the deepest portion of the well. This higher temperature at the bottom 400 feet section of the well will allow Chena to re-inject water into warmer fractures which should speed up the reheating of the geothermal water.

Figure 1: Static Temperature Profile of Re-injection Well #2

Arctic Drilling didn't encounter any surprises during drilling, primarily drilling through granite without encountering any large fractures causing them to struggle in bringing up the cuttings. The drilling logs for well #2 are included in Attachment 3.

Chena chose to deepen the production well TG-8 from 1020 feet to 2500 feet because it was the warmest well on site and because it was an easy location for the Arctic Drilling to set up their drill rig. Well TG-8 had previous static well logs that recorded 167°F at 1080 feet. Just as with the re-injection well, Arctic Drilling used a water hammer with a button bit to complete the well. While drilling through the granite, Arctic Drilling seemed to encounter fractures frequently from 1080 feet to 1920 feet. Much larger fractures were encountered at 1920 feet and 2320 feet. The drilling logs are included in Attachment 4.

Production well TG-8 was completed to 2500 feet at the by the end of March 2013. Well TG-8 has 12-inch casing cemented in to 60 feet, 8-inch casing to 1000 feet, and an 8-inch

perforated liner from 1000 feet to 2500 feet. A detailed well illustration is provided in Attachment 5.

A static log was taken after the completion of well TG-8 and there has been an increase in well temperature from 167°F to 178.5°F. There is approximately a 1000 foot section of the well from 900 feet to 1900 feet where the well is above 177.5°F. At depths greater than 1900 feet the well begins to cool with the bottom of the well at approximately 169°F. Figure 2 shows the temperature profile of well TG-8.

Figure 2: Static Temperature Profile of Production Well TG-8

Executive Summary

Drilling on a re-injection well, well #2, has been completed and the casing has been cemented in. Chena was able to reach a warmer temperature zone than the other re-injection wells on-site, which will allow for the water being returned to the reservoir to reheat faster and extend the life of the geothermal field. The water that exits the power

plant is typically 130°F and will be re-injected into fractures that are 173°F as opposed to 122°F fractures found in the other wells.

Production well TG-8 has been deepened from 1020 feet to 2500 feet and has seen an increase in high temperature from 167°F to 178.5°F. The high temperature range is located from 900 feet to 1900 feet with a cooling trend at greater depths. Chena anticipates that the 1000-foot range of high temperatures will have enough producing fractures to increase the energy delivered to the power plant.

Chena anticipates being able to produce additional electricity at the resort and has begun tying the new wells into the existing piping. Chena is also currently installing a new ORC geothermal power plant that uses a screw expander to drive a synchronous generator. This new power plant will allow Chena to reduce and potentially eliminate diesel consumption for electrical needs for the resort by providing a synchronous base-load power source that will be capable of maintaining the grid frequency on its own. Other future work could include plugging the cooler section at the bottom of well TG-8 if that section produces too much cooler water. If the reservoir is capable of producing even more electrical power than the resort consumes, Chena will look into the possibility of exporting the power to the local Fairbanks grid or using the power toward a value added product such as greenhouse lighting.

Attachment 1

“Chena Hot Springs Data Collection Project May-August 2009”

Report prepared by Dr. Joanna Mongrain

Chena Hot Springs
Data Collection Project
May-August 2009

INEacep09.110

s-12531

Report Prepared by

Joanna Mongrain

Data Collected by

Dick Benoit

Peter Illig

Sumanth Belawadi

Table of Figures

Figure 1 Well Locations at Chena Hot Springs Resort (Figure modified from Erkan et al.)	4
Figure 2 Temperature Profiles for TG3	5
Figure 3 Temperature Profiles for TG9	6
Figure 4 Temperature Profiles for Well 1	7
Figure 5 Injection Temperature Log for Well 1.....	8
Figure 6 Temperature Profiles for Well 7.....	9
Figure 7 Temperature profiles for TG12	10
Figure 8 Static Pressure Gradient for TG3	11
Figure 9 Static Pressure Gradients for TG9.....	12
Figure 10 Static and Injection pressure gradients for Well 1.....	13
Figure 11 Pressure Gradients for Well 7.....	14
Figure 12 Pressure Monitoring at Well 7, June 1-2	16
Figure 13 Closeup of Pressure Monitoring at Well 7, June 1-2	17
Figure 14 Pressure Monitoring at TG9, June 1-2	18
Figure 15 Pressure Monitoring at TG1, June 1-2	19
Figure 16 Pressure Monitoring at TG3, June 1-2	20
Figure 17 Pressure Monitoring at Well 4, June 1-2.....	21
Figure 18 Pressure Monitoring at Well 7, June 2-3	22
Figure 19 Pressure Monitoring at TG1, June 2-3	23
Figure 20 Pressure Monitoring at TG3, June 2-3	24
Figure 21 Pressure Monitoring at TG12, June 2-3	25
Figure 22 Pressure Monitoring at Well4, June 2-3	26

Contents

Introduction.....	4
Temperature Surveys	5
TG3	5
TG9	6
Well 1.....	7
Well 7.....	9
TG12	10
Pressure Gradient Measurements.....	10
TG3	11
TG9	12
Well 1.....	13
Well 7.....	14
Well Interference Testing	14
Interference test timeline	15
June 1st-June 2nd, 2009.....	15
Well 7.....	16
TG9	18
TG1	19
TG3	20
Well 4.....	21
June 2nd-June 3rd, 2009	22
Well 7.....	22
TG1	23
TG3	24
TG12	25
Well 4.....	26
Summary	26
References	28

Introduction

This summary document details and analyzes the temperature and pressure gradient logging and interference testing carried out in May and June 2009 at Chena Hot Springs. The data collected builds on prior data collected as part of the GRED III project and was designed to help start the quick development of a numerical reservoir model. Understanding how the reservoir dynamics have changed since 2006 when the power plan went into operation allows us to assess whether the reservoir is being produced sustainably and potentially offer recommendations for better well management. A new deep well, TG12, was drilled over the summer and this dataset also helps to capture the state of the reservoir prior to production from this new well.

Figure 1 Well Locations at Chena Hot Springs Resort (Figure modified from Erkan et al.)

Figure 1 illustrates the well locations at Chena Hot Springs. The current production wells are Well 7 and TG8. TG7 and Well 1 are used for reinjection of the outlet fluid from the power plant with the majority of the injected fluid being injected into TG7. The wells marked with red stars are the wells which were monitored during this data collection project.

Temperature Surveys

A comprehensive set of temperature logs were taken between May 21st and May 25th on TG3, TG9, TG12, Well11, Well7 and Well4. Additional logs were taken of TG12 as the hole was deepened. These temperature logs allow us to assess any overall degradation of the resource. More importantly changes in the shape of the temperature profiles since the start of the power plant in 2006 reveal reservoir dynamics.

TG3

Figure 2 Temperature Profiles for TG3

Figure 2 displays the static log profiles for TG3 taken since July 2005 when the well was drilled including the most recent May 2009 profile. TG3 is located in the western end of the field and is not used for production. It can be viewed as an observation well for the shallow intervals of TG9 and TG8. TG9, as will be discussed later, shows an influx of cool fluid around a depth of 200ft and also a possible influx of cooler water above this point. This is reflected in the overall cooling of TG3. The near isothermal interval from somewhere above 50 ft has cooled increasingly since 2006. A positive temperature profile below this may reflect the outflux of this cooler water. Bottom hole temperature for this well has declined by 12°F.

Above 100 ft a temperature decline of 52°F is observed since 2006. Inspection of drilling logs does not reveal any noticeable fractures.

TG9

Figure 3 Temperature Profiles for TG9

Figure 3 displays the temperature profiles for TG9 taken since April 2006. TG9 is located in close proximity to TG8 and Well 7. A log run in April 2006, a few months after drilling shows a temperature profile of 160°F fluid flowing almost to the surface. This is representative of the dynamic underground conditions at the time. Logs taken after 2006 show progressive cooling above ~615 feet. The cooling trend has a unique “stair-step” signature, characteristic of colder water flowing into and then down the wellbore before exiting through some fractured/highly permeable zone. The high temperature gradient interval at ~450 ft depth correlates well with a large fracture encountered during drilling. The high temperature gradient interval extending from ~550 and 615 in the latest log suggests a more vertically extensive, permeable fracture zone. The water intake can be traced to a depth of ~200ft, just above a cool near isothermal interval, with current inflowing fluid having a temperature of ~70°F, a drop in temperature since April 2007 of around 35°F. The small positive temperature gradient is due to warming of the cool inflow fluid by the hotter

wellbore. The temperature profile below 615 feet is unchanged since 2006 at 160°F suggesting that there is rapid recharge of the reservoir at depth. The movement of cold water in TG9 suggests that the TG9 wellbore is currently acting as a conduit connecting the cooler higher pressure water with warmer lower pressure fluid below. This has the potential to degrade deeper reservoir temperatures and so decrease the temperature of the production wells. A possible fix would be cementing the interval at 200ft or simply filling the hole in to prevent it acting as a conduit

Well 1

Figure 4 Temperature Profiles for Well 1

Figure 4 displays the temperature profiles taken for Well 1 since October 2005. Well 1 is the most easterly well in the field and is thought to define the eastern margin of the thermal anomaly. Static temperature profiles show a general cooling trend since between 2006 and 2007 of ~ 5°F. The shallow intervals in the eastern part of the field are thought to be strongly influenced by mixing of cold meteoric water with the thermal fluid. The re-injected fluid has a temperature of ~122°F representing a drop in temperature of ~35°F from the inlet temperature at the power plant.

Figure 5 Injection Temperature Log for Well 1

Figure 5 shows an expanded view of the injection temperature log for Well 1. The injected fluid has a temperature $\sim 122.1^{\circ}\text{F}$ and the temperature profile is fairly constant to a depth of 180 ft. Below 180 ft, there is a negative temperature gradient which may indicate that this is the depth at which the injected fluid reenters the reservoir. Since the depth of the well is only 320 ft, the interval for the fluid to be injected is small, possibly explaining the low injectivity of Well 1. It is difficult to assess this precisely without in line flow meters but it is expected that the majority of the re-injected fluid enters the field through TG7, a well much closer to the production wells than Well 1. It may be worthwhile deepening Well1 in the hope of increasing its injectivity and allowing greater time for heating of the re-injected fluid before it reaches the production wells.

For reservoir modeling it will be essential to know the injected volume into this well. It is recommended therefore that in-line flowmeters are installed. An additional benefit will be more comprehensive well test information in the future.

Well 7

Figure 6 Temperature Profiles for Well 7

Well 7 is currently a main production well for the power plant. The logs from 2006 show two hot lateral flow zones above 200ft. This well was cemented to 450 feet and we therefore do not see the effect of the flow zones in the well today. The 2009 logs are flowing wells and show an isothermal temperature profile of 150 degrees, this is ~10 degrees cooler than the original BHT and suggests that the reservoir is cooling slightly in this area. This might result from over production, mixing of cooler zone waters through TG9 conduit or inadequate time for re-injected fluids to attain thermal equilibrium prior to production.

TG12

Figure 7 Temperature profiles for TG12

TG12 was drilled this summer to a depth of ~2600 feet in the hope that the suggested deeper hotter geothermal fluid could be tapped. Repeated temperature surveys were carried out between May and October 2009 as the well was deepened. The maximum temperature encountered was 165°F at a depth of 1500 ft similar to the original maximum temperature of nearby Well 7 (169°F) which produces from a depth of 600ft. TG 12 is slightly cooler than the maximum temperature of 176°F measured at TG8. It appears therefore that the resource temperature does not increase between 600 and 1500ft in this the main hot producing area of the field.

Pressure Gradient Measurements

Static pressure gradients are useful for to determine the stabilized reservoir pressure for a well. Reductions in reservoir pressure infer that there is insufficient reinjection. Build ups in pressure adjacent to injection wells can indicate low injectivity.

TG3

Figure 8 Static Pressure Gradient for TG3

The static pressure gradients for TG3 changed very little between 2006 and 2007 in spite of the increased production from the field after the power plant was brought on line. Unfortunately, the data taken in May 2009 has some errors and it is not possible to determine the true static pressure. If the static pressure is well represented by the profile between 60 and 100ft then the pressure drop at TG3 has been minimal. The sharp kink below 100ft invalidates the data.

TG9

Figure 9 Static Pressure Gradients for TG9

The static pressure gradient surveys indicate that reservoir pressure in TG9 has declined by approximately 35 psi since 2007. This is of concern as TG9 is representative of the productive wells and a drop in reservoir pressure leads to a drop in well productivity. Increasing the injection rate or decreasing the volume of fluid taken out for other projects at the Hot Springs might mitigate this.

Well 1

Figure 10 Static and Injection pressure gradients for Well 1

The static pressure data indicate that the shallow reservoir pressure changed little between August 2006 and March 2007. This suggests that the re-injected fluid is not building up around the well but is supporting the field as a whole. The injection log taken on 22nd May 2009 shows that the injection pressure is ~20 psi greater than the reservoir pressure. This small injection pressure support the interpretation of the temperature profile as indicating low injectivity for the well.

Well 7

Figure 11 Pressure Gradients for Well 7

Well 7 is an artesian well as confirmed by the 2006 static pressure log which showed a positive pressure at surface. The latest flowing downlog for this well shows an increase of ~35 psi on the static log due to pump operation.

Well Interference Testing

An interference test was carried out from June 1st-June 3rd, 2009. The aim of this test was to characterize the reservoir dynamics at Well 7, the main producer and simultaneously assess how the production at Well 7 affects the field as a whole. Well 4 and TG3 were fitted with pressure bombs and the pressure monitored using Magtech data loggers. Well 7, TG1 and TG9 were monitored using Kuster 10 strain gauges. On June 2nd, the Kuster gauge from TG9 was transferred to TG12 in order to assess connectivity between this new well and the rest of the field.

In a traditional interference test, a well will be shut in and nearby wells monitored for the effect of the shut in on the bottom hole pressures in the well. Key attributes are how fast the effect of the shut in well is “felt” at another well. This is an indication of reservoir connectivity and permeability. The magnitude of the effect can also be analyzed to assess the connected volume of fluid to both wells. In order to simplify the analysis, all other well parameters should remain the same. However, in a working field this is not always possible.

This test differs from a conventional interference test in that, in order to maintain sufficient production to the power plant, Well 5 pump was started once Well 7 pump was shut off. Some of the monitored wells appear to be responding more to the Well 5 pump starting than the Well 7 pump being stopped. In addition, Well 7 was not truly “shut-in”, the pump was stopped but artesian flow of ~30gpm continued throughout the test. A TG8 well head failure due to high pressures developed when the Well 7 pump was stopped is informative but also complicated early test interpretations.

In the future it would be useful to time well tests with scheduled down time at the power plant.

Interference test timeline

The data for each well is given for two time periods. The first focuses on changes in well pressure due to shut down of the Well 7 pump and the start up of Well 5 pump. The second period focuses on well responses to the restarting of Well 7 on June 2nd. Table 1 shows the depth location of the Pressure bombs/Kuster gauges within the wells

Table 1 Location of Pressure bombs/Kuster Gauges within wells

Well	Gauge Depth (ft)
Well 4	60
TG3	20-30
TG9	526
TG1	100
Well7	525
TG12	198

June1st-June2nd, 2009

On June 1st at 10 10 the Well 7 pump was stopped in order to install the lubricator allowing the Kuster gauge to be set in the well. At 10 40 the pump was restarted. At 13 29, Well 7

pump was stopped again in order to proceed with the interference test. In order to maintain sufficient production at the power plant, the Well 5 pump was started. At 14 30, TG8 experienced a wellhead failure, presumably due to pressure build up in that area as Well 7 was flowing only under artesian flow at ~30gpm. The TG8 pump was restarted at 14 45 but had to be stopped after a repeat well head failure at 14 46. At 15 08, TG8 was restarted and experienced no further failure events. No further changes in field operations occurred until June 2nd at 14 37 when Well 7 pump was restarted, ending the interference test. These events are all clearly labeled on the following diagrams. Reservoir connectivity can be assessed by observing the magnitude of changes in pressure behavior to the noted events and the delay in response time.

Well 7

Figure 12 Pressure Monitoring at Well 7, June 1-2

As expected when the Well 7 pump was stopped, the pressure dropped from 275 psi to 208 psi by (~67 psi) and then rebounded as the system stabilized at 225 psi (Figure 12). The wellhead failure at TG8, which required a shut down of the pump and therefore a reduction in flow from TG8, caused an instantaneous increase in pressure of ~1.5psi at Well 7 which then

dropped as the pump was restarted. A close up view of the pressure changes at Well 7 during the changing conditions at TG8 can be seen in Figure 13.

This rapid communication between Well7 and TG8 is expected from the flow testing of Well 7 done during the GRED III project which also showed instantaneous response at TG8 due to flow at Well7.

Figure 13 Closeup of Pressure Monitoring at Well 7, June 1-2

TG9

Figure 14 Pressure Monitoring at TG9, June 1-2

In Figure 14, TG9 shows a rapid response to the Well 7 pump being stopped to install the lubricator prior to the test. Pressure increases from 56 psi to 81 psi when the lubricator is installed and drops rapidly to a stabilized pressure of 60 psi when the pump is restarted. An instantaneous response when the Well7 pump is stopped for the test, increases the pressure to 82 psi where it is beginning to stabilize when the TG8 wellhead failure occurs. As the rate from TG8 is reduced during successive well head failures and pump stops, the pressure at TG9 rises by ~3psi, before dropping back by 1 psi and stabilizing at 83 psi after TG8 is stabilized. This behavior is expected from the GRED III testing which showed an instantaneous response at TG8 and TG9 to flow at Well 7.

TG1

Figure 15 Pressure Monitoring at TG1, June 1-2

Interpretation of the pressure response of TG1 to Well 7 pump stopped is complicated by the startup of the Well 5 pump. A flow test on Well 5 during the GRED III project showed a sharp pressure drop of 8psi as the Well 5 was pumped at a very high rate (~1185 gpm). In Figure 15 it appears that TG1 responds to both the Well 7 pump stopping and Well 5 pump starting. A comparatively slow build up to 15.1 psi over 25 minutes after the Well 7 pump is stopped is followed by a sharp pressure decline to 14.7 psi and then a very slow pressure increase to almost 15psi. The magnitudes of the pressure changes are smaller than in the GRED III testing suggesting that the flow rate from Well 5 with the pump is much reduced.

TG3

Figure 16 Pressure Monitoring at TG3, June 1-2

Testing during GRED III showed that TG3 had no appreciable response to Well 5 flow testing and therefore we would expect the response of TG3 to be exclusively due to the activity at Well 7 and TG8. Figure 16 confirms this expectation. The Well 7 pump shut off results in an immediate pressure increase for 30 minutes which begins to stabilize prior to the TG8 wellhead failure. After TG8 stabilizes, the pressure plateaus around 14psi before increasing at 20 00. This increase may be due to decreased flow from Well 7 as there is no other well activity to indicate a major change. Artesian flow rates for Well7 were measured sporadically but without having continuous measurements it is difficult to tell how the system is responding to changes in Well 7. Confusing the matter further, Well 4 also shows a dramatic change in pressure with no known activity around 20 00 so there may be another explanation. Well 4 and TG3 do not generally show the same response to changes in well status.

Well 4

Figure 17 Pressure Monitoring at Well 4, June 1-2

Pressure changes at Well 4 are dominated by the start up of Well 5 pump. The fairly rapid decrease in pressure from 40.2 to 38.8 psi once Well 7 pump is stopped cannot be explained by Well 7 behavior but can be explained by increased production from the nearby Well 5 causing a localized pressure drop. The sharp increase in pressure shortly after 20 00 does not correlate with any known well activity. However, a similar trend is seen in TG3. The rise could be plausibly be explained by a decreased pump rate in Well 5 or an increase in injection rate at TG7.

June 2nd-June3rd, 2009

Well 7

Figure 18 Pressure Monitoring at Well 7, June 2-3

The main activity on June 2nd was the restarting of Well 7 pump. In Well 7, this caused an instantaneous spike in pressure from 226 psi to over 300 psi. This stabilized over a period of 90 minutes to 269 psi ~5 psi lower than the original pressure. This discrepancy may be the result of resetting the Kuster gauge at a slightly different depth than during the first part of the test or maybe a function of the pump. It is unlikely to be a localized pressure decline as TG8 and TG9 showed increases in pre-test pressure.

TG1

Figure 19 Pressure Monitoring at TG1, June 2-3

There is an instantaneous pressure increase at TG1, around 90 minutes after the Well 7 pump is restarted at approximately the same time that the pressure at Well 7 stabilized. It is unclear when the Well 5 pump was stopped but this data suggest that it may have been stopped only once the pressure, and hence the flowrate, at Well 7 stabilized (~90 minutes). If this is the case, TG1 shows an instantaneous and rapid response to Well 5 pump stopping. A small pressure decline of ~0.05psi prior to this may be in response to Well 7 pump restart.

TG3

Figure 20 Pressure Monitoring at TG3, June 2-3

The TG3 response to the restarting of Well 7 shows a rapid pressure drop of 3 psi about the time the pressure in Well 7 stabilizes (approx 90 minutes after the well pump is restarted). This confirms the excellent communication between Well 7 and TG3. Following the rapid pressure drop the pressure at TG3 then increases, perhaps due to redistribution of fluid between TG8 and Well7 and fluctuating production from these wells. Again, it is essential to understand the volumes being produced from each well in order to fully interpret the tests.

TG12

Figure 21 Pressure Monitoring at TG12, June 2-3

At the time of the test, TG12 had been drilled to a depth of ~600 ft. As can be seen in Figure 21, TG12 showed no response to the Well 7 pump restart indicating that at this depth it is not in communication with the other productive wells, TG8, TG9 and Well 7 or Well 5. A repeat of this test should be performed now that the well has been deepened to 2500ft to determine if the well is in communication with other wells in the reservoir.

Well 4

Figure 22 Pressure Monitoring at Well4, June 2-3

Similar to TG1, Well 4 shows an increase in pressure of 1 psi ~90 minutes after the restart of Well 7 pump, presumably due to the stopping of Well 5 pump. The pressure increases slowly by 1 psi before decreasing slowly overnight

Summary

The conceptual model detailed in the GRED III report for the Chena Hot Spring reservoir suggested a shallow predominately conductive zone with mixed meteoric and thermal fluids with a deeper productive zone exhibiting convective behavior. The two zones are separated by a lateral barrier to flow, inferred from distinct temperature and pressure profiles, so that the deeper zone seems unaffected by cooler water above.

The current data supports this conceptual model. The deeper resource characterized by the isothermal section in TG9 (Figure 3) has experienced little if any temperature decline. Some temperature decline ($\sim 10^{\circ}\text{F}$) may be observed in Well 7 but as the recent logs are flowing logs this is not certain. Pressure decline for the wells is also limited. These observations

suggest that the field is being produced in a sustainable manner and that injected volumes are sufficient to maintain productivity of the reservoir.

However, the temperature at the power plant has declined since 2006 causing concerns for power generation. The reason for this is illustrated by the temperature profile of TG9 (Figure 3) which shows a clear influx of cooler water down the wellbore, flowing out and mixing with deeper hotter fluids. The effect of this can be seen in the dramatic temperature decline in TG3 (Figure 2) and is presumably also affecting the producing temperature of TG8, one of the main production wells. Cementing the influx zone in TG9 should improve this situation.

The possible cooling trend seen in Well 7 (Figure 6) suggests that the reservoir would benefit from increasing the relative injected volume in to Well 1 (at the far eastern part of the field) over TG 7. This could be achieved through a deepening of Well 1.

Interpretation of the interference test was complicated by both a lack of data on flow volumes and also changing field operations during the test. Flow volume data will be essential for calibrating any reservoir model. In particular it would be good to know the injected/ produced volume ratio. This can be achieved relatively cheaply through installation of inline flow meters. Future test interpretation could be improved by scheduling tests with planned maintenance of the power plant.

At the time of the interference test, TG12 had been drilled to a depth of 600 ft and showed no communication with the Well 7 and Well 5. In order to assess the connectivity of TG12 with the reservoir and determine optimum operating conditions, this well should be retested.

References

Benoit, D., Chena Hot Springs well interference testing report 2009 June 1-3. Unpublished report prepared for Chena Hot Springs Resort, 3pp.

Erkan, K., Holdmann, G., Benoit, W., Blackwell, D., 2008. Understanding the Chena Hot Springs, Alaska, geothermal system using temperature and pressure data from exploration boreholes. *Geothermics* 37, 565-585.

Holdmann, G., Benoit, D., Blackwell, D., 2007. Phase 1 final report, integrated geosciences investigation and geothermal exploration at Chena Hot Springs, Alaska. GRED III report for Chena Hot Springs prepared for the U.S. Department of Energy Golden Office, Golden, CO, USA, 104pp.

Attachment 2

Detailed Well Diagram Illustration of Well 2

Well 2

Drawing Not To Scale

Attachment 3

Well #2 Drilling Logs

Chena Injection well report

Feet, from surface

0 - 10 gravel fill

10-20 black muck

20-30 loose granite with some water, 38F

30-37 soft granite

37-45 med hard grey granite

45-48 hard granite , refusal at 48 feet with hole in front of casing

48- 70 consistent hard granite

70-120 fractured hard granite , difficult jerky drilling through cracks, 20 gpm water, 43 F

120-230 consistent gray granite, 43 F

230-265 hard granite with cracks with water est 50 gpm, 50 F

265-580 hard consistent grey granite water still at 150 gpm. 70F

580-620 hard granite with some fractures and more water up to 250 gpm, 85F

620-880 consistent hard light grey granite, 90F

880-1220 harder dark grey granite, very slow drilling, up to 2 hours per joint, 94F

Resume drilling at 1220 ft level, 7,7/8" hole, drilling with 200 gpm clear water and water hammer

No temperature readings taken while drilling with water, all discharge is fairly cold

Typically takes 30 seconds to get circulation discharge after starting pump at joint changes, no noticeable fluid loss throughout entire depth

1220-1580 Grey granite, hard, consistent, drilled with water hammer, no noticeable jerky spots until almost 1580, assume jerky drilling there is from out of gauge bit.

Tripped out hammer and worn bit and changed over to 77/8 rotary bit and drill collars, drilling using 200 gpm clear water,

1580-1720 Grey granite, hard, drills at 20 feet per hour

1720-1740 Grey granite, a little faster drilling, 20 feet in 40 minutes, jerky drilling possible fractures, no fluid return loss

1740-1760 Grey granite, a little bumpy drilling, soft spot at 1760

1760-1780 Grey granite, hard with color change from almost white to dark grey

1780-1820 Grey granite 20 ft/hr

1820-1860 Grey granite, tight spots, fractures? No loss in returns

1860-1900 Grey hard granite, color change to tan for 2 to 3 feet

1900-1980 Grey hard granite, consistent, 20 ft/hr, smooth drilling no bumps.

Bit started jumping at 1975ft assumed roller cone going out, tripped out of hole, one loose roller on bit

Back in hole with water hammer and new bit

1980-2100 Dark grey hard granite with alternating streak of brown granite

2100-2140 Grey hard granite, rough spot near 2140 possible crack? or running wrong wob

2140-2160 Grey hard granite, sticky spot near 2160, may have lost circulation for a minute

2160-2220 Grey hard coarse grained granite, sticky spot at 2210

2220-2240 Grey hard granite, cracks? Bumpy spots,

2340-2390 Grey hard granite, hammer quit running

Trip out of hammer out of hole, trip back in hole with roller cone bit

2390-2560 Dark grey granite hard and consistent, smooth drilling

2560-2700 Dark grey, hard and fine grained granite, smooth slow drilling

Attachment 4

Well TG-8 Drilling Logs

Well 8 drill log

Drilling log:

360 - 1020 ft, med hard grey granite, reamed hole from 6" to 8", est 500 gpm flow produced while drilling w/air hammer

1020 - 1377 ft , med hard granite, drilled at 80 feet per hour with air hammer, did not notice any fracture zones but we did pick up more water either from the rock or maybe we were just further developing the existing fracture zones, by 1377 feet we were producing about 500 gpm more than we were at 1020 feet.

1377 - 1500 ft, drilling with Wassara water hammer we drilled at about 80 feet per hour but with many areas of fractures and softer rock, about every 10 feet or so and circulation could not keep up so we tripped out to change over to rotary drilling after getting stuck in the hole and mudding up the hammer.

1500 - 1580 ft --drilling with 7,7/8 hard formation IADC 832 bit, very smooth drilling at 30 ft per hour

1580 - 1600 ft-- bumpy drilling, fractures and soft spots, no L.C.

1600 - 1720, smooth drilling at 30 ft per hr, grey granite

1720 -1740, badly fractured rock and void from 1735 to 1737 ft, grey granite

1740 - 1760, smooth drilling 30 ft /hr. grey granite

1760-1780, very soft rock, void spots, grey granite

1780-1860, smooth drilling 30 ft /hr, grey granite

1860-1890, fractures and soft spots, some delay for returns, noticed some yellow, blue and black grains in cuttings, otherwise grey granite

1890-1920, some smaller fractures or cracks, grey granite

1920 - 1960, big fractures/ cracks at 1940 ft, grey granite

1960 - 2,000 smooth drilling, 30 ft/hr

2,000 - 2020 soft grey granite/ 2,000 psi holdback

2020 - 2040, hard grey granite, 20 ft / hr smooth drilling

2040 - 2060, hard grey granite, soft spot/crack at 2050'

2060-2080, some small fractures, soft spots

2080-2170, hard grey granite, smooth drilling, 30 ft/hr

2170-2180, big cracks and real soft grey granite

2180-2240, hard grey granite, smooth drilling, 30 ft/hr

2240-2260, Lost circulation, no noticeable fractures but circulation was down to 20 gpm

2260-2320, hard grey granite, smooth drilling, 30 ft/hr

2320-2340, grey granite, big fracture, 2325' to 2346', lost circulation completely for 20 min.

2340-2500 hard and smooth grey granite, 30 ft/hr

Attachment 5

Detailed Well Diagram Illustration of TG-8

Well TG-8

Drawing Not To Scale