The 2010 Akutan Exploratory Drilling Program: Preliminary Findings

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ABSTRACT

In 2010, a geothermal exploratory drilling program was conducted on Akutan Island, Alaska. The purpose of the drilling program was to obtain temperature gradient data to constrain resource capacity. The wells were designed to allow long-term monitoring and possible testing of the Akutan geothermal field. The 2010 drilling operations were carried out using wireline core equipment and were supported by helicopter. Two wells were drilled to respective depths of 253.9 meters and 457.2 meters. The first well (TG-2) was drilled directly above an outflow aquifer(s). A preliminary analysis of the TG-2 well showed that the well made 2-phase flow with a 190 liter per minute liquid phase via a 96 mm hole and from a depth of 177 to 178 m. The second well (TG-4) was drilled at the margins of the modeled outflow in order to conceptualize the size of the outflow resource. That well had very low permeability but displayed a high temperature gradient, with an extrapolated temperature of 164 deg C at 457 m. Some evidence that a deeper, hotter resource exists at or near the TG-4 site was found using mineralogical data. Preliminary analysis of data suggests that a pumped production well at the TG-2 site would be capable of a maximum production of 2.3 MW. Geochemical sampling of the fumarole gasses was carried out on the flank of the Akutan Volcano concurrent with the drilling. The data obtained from drilling will be combined with core and geochemical analysis in order to form a resource model of the field preliminary to production drilling.

Introduction

Akutan Island is located 790 miles southwest of Anchorage and 30 miles east of Dutch Harbor. As a volcanic island with accessible hot springs, it has been the subject of geothermal resource studies since 1979. In summer 2010, an exploration drilling program was carried out with two TG wells drilled in Hot Springs Bay Valley. Since the Akutan Geothermal area is roadless, the 2010 drilling operations were supported by helicopter. The 2010 program included the drilling of up to four small-diameter core holes, at locations given in Figire 1. Due to budget constraints, only two of the four planned holes were actuallydrilled; these are marked with black arrows in Figure 1.

Planned Drilling Program

The 2010 exploratory drilling plan was designed for long-term monitoring and possible testing of the Akutan geothermal field. The hole(s) were completed as temperature gradient wells and available for future monitoring and testing. Additionally, detailed analysis of the core will be conducted at participating universities. These studies will be combined into a resource model that will be

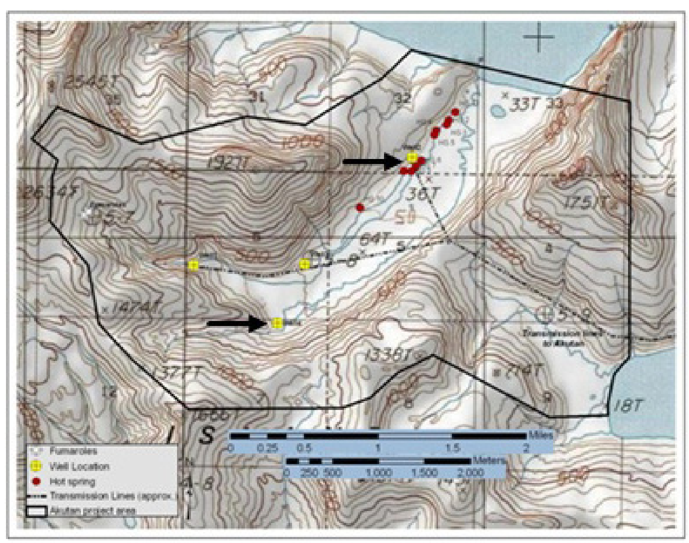

Figure 1. Map of the Akutan Geothermal area, showing four original planned exploration well locations. The two holes drilled in 2010 are marked with black arrows.

used to determine the locations and depths of production holes, and in planning geothermal development.

Well TG-22 was drilled first. This well was sited directly above the modeled outflow aquifer(s). Well TG-4 was sited at the margins of the modeled outflow in order to conceptualize the size of the outflow resource. A diagram of the planned well design for both wells is shown in Fig 2.

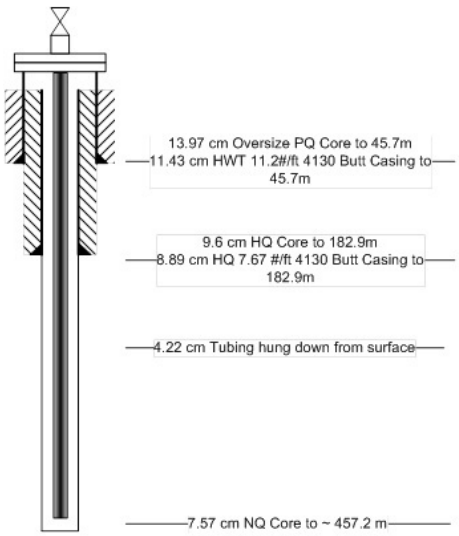

Figure 2. Well design for Hot Springs Well (TG2), with a planned TD of 457.2 m.

Summary of Preliminary Drilling Results

Drilling Operations

In general, the drilling of TG-2 proceeded more slowly than anticipated. The delays were caused by a combination of the bad weather conditions and supply line problems notorious in Alaska's Aleutian Islands; and equipment problems associated with drilling an extremely permeable and hot well with a core rig.

A 16.97 cm conductor was installed at 8.53 m. The hole was then drilled to 47.85 m using PQ tools with an oversized (13.97 cm) kerf on the bit. The hole was cased using HWT casing and cemented. Blow-out prevention equipment (BOP) was installed and BOP and formation integrity tests were performed. Drilling resumed using HQ tools (9.6 cm). Drilling proceeded slowly as various problems (high torque, sticking and lost returns) arose and were mitigated. The problems were due primarily to the extreme heat and permeability of the formation at relatively shallow depths. Barite-weighted drilling mud (1.08 kg/L) or CaCl brine (1.15 kg/L) was used throughout the drilling, and the hole required constant circulation because in most instances where circulation was stopped or slowed, the well flowed. The well showed a particular propensity to flow when the core rod was being pulled from the well due to changes in the annular pressure differential and the fact that it is not possible to run inside blowout protection when wireline coring.

Figure 3. Photograph showing Hot Springs Well site and helicopter support. Photo by Neil McMahon, AEA.

Throughout the drilling, downhole temperatures were recorded at 30' intervals with a maximum registering thermometer (MRT). These temperatures are not accurate records of the true geothermal temperatures due to the cooling effect of drilling fluids. However, the MRT readings do give a ball park idea of where hot zones are located.

Between 178.31m -178.92m a fracture zone was encountered into which all drilling fluid returns were lost. The MRT reading at the fractured interval was 150 °C. Soon afterward the well began flowing and another MRT was recorded at 181.7 °C. This was the maximum temperature recorded by MRT for the entire well.

At 183.79m, an intermediate string of 8.89cm casing was cemented in, and BOP and leak-off tests were performed. The leak-off test did not conform to state regulations, so a large amount of cement was squeezed around the shoe and into the surrounding formation. This cement job likely "sealed off" the productive fracture.

From 183.79m, drilling was resumed using NQ (7.57 cm) tools. Drilling was halted at 253.9m due to ongoing difficulties related to high temperature and tool failure. After retrieving the core at TD, the hole was circulated for over two hours, and the pressure/temperature (P/T) logs were commenced.

In contrast to TG-2, drilling proceeded more rapidly than anticipated at TG-4, with relatively few mechanical or equipment problems. There was very little lost circulation in TG4, and all formation integrity tests (i.e., leak-off tests) were successful. While this was positive in terms of the pace of the drilling, it suggests that TG4 has lower permeability than TG2.

10.06m of 16.9cm conductor was set from 11.58m, and the hole was drilled out with a 13.97cm kerf PQ bit. Before the surface casing was installed at 186', a small amount of fluid was lost (5 bbls/hr) at 43.59m and more between 51.2m and 57.3m (7-10 bbls/hr). This was in a zone of fractured tuff (relatively permeable layer) and a small temperature increase was registered at 45.72m – 47.55m and again at another fracture zone 56.39m. These are probably not substantial hot aquifers as temperatures only rose slightly after considerable halt in circulation, and regular circulation temperatures were still recording low (<100 °C). A cement plug was installed across the lost circulation zone (spanning 36.58m-52.43m), and the hole was cased and cemented with HWT (11.43cm OD).

The hole was drilled to 181.66m using HQ (9.6cm diameter) tools, and a second string of casing was installed (HQ, with an outer diameter of 8.89cm). After testing the BOP and drilling out to 182.88m with NQ (7.57cm diameter), a leak-off test was run. Leakoff did not occur before reaching a 1.2 psi/ft gradient, so testing halted and drilling was resumed. The well was TD'd at 457.2m.

PT Data

A memory-type Pressure/Temperature (PT) tool was used for the end-of-well PT surveys. Three runs were recorded at 12, 24 and 36 hours after circulation ended. For every run, stops were made at 6.1m stations. Because these surveys were taken so soon after the well was drilled, the temperature readings are still influenced by the cooling effects of fluid circulation. Therefore the data represent unequilibrated downhole temperatures.

In order to predict the *equilibrated* downhole temperature, we used the Horner method to extrapolate ultimate values for the reservoir temperature based on curves generated from the three survey points from each depth. An example of an extrapolation is shown in Figure 4.

The final depth vs. temperature plot generated from extrapolated values is shown in Figure 5.

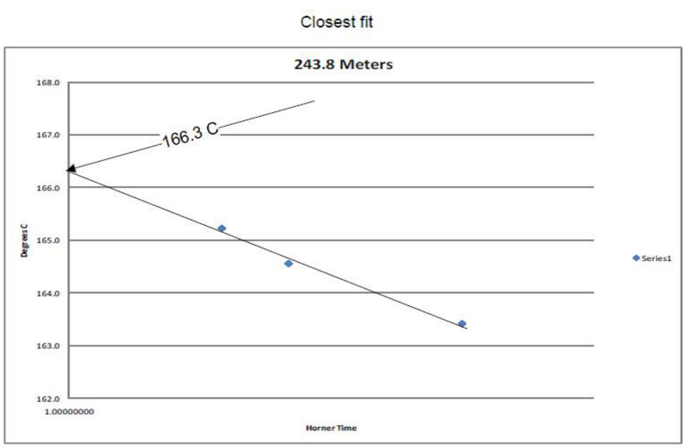

Figure 4. Graphic showing method for extrapolating the equilibrated reservoir temperature based on three temperature readings over time at a fixed depth interval at TG2 (here, 243.8 m or 800 ft).

Although the downhole surveys show a drop in temperature between 179.83m and 188.98m, we know that the downhole temperature was actually 181.67 °C between 178.31-178.92m from the MRT reading. The apparent cooling is likely the result of cement injected across that entire area for the leak off test.

The plot of the extrapolated temperature vs depth for Well TG4 shows a relatively rapidly increasing temperature gradient until ~274.32m, transitioning to a slowly increasing temperature gradient from 274.32m-457.2m. The minor temperature fluctuations from 274.3m-457.2m are probably a product of minor flow from small fracture sets. The facts that there was no temperature reversal and that the gradient continues to increase suggest there could be a deeper, hotter aquifer below 457.2m that was not penetrated by drilling.

An injection test was performed on well TG4 to determine its permeability. This test suggests that the well has generally poor permeability. However, there is presumably better permeability below 457.2m if a deeper, hotter aquifer exists.

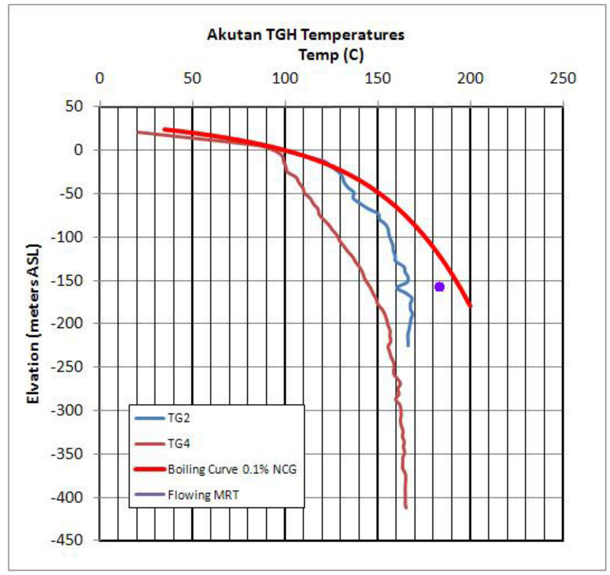

Figure 5. Plot of Horner-extrapolated TG data from Akutan Geothermal Wells TG-2 and TG-4. Also shown is the single MRT reading at productive interval 178.31-178.92m prior to cementing. Maximum temperature was 181.67°C at 178.31m.

Geology

Complete mud logs were recorded for both TG wells. In general, the formations encountered were generally homogeneous volcanic flows of andesite, basaltic andesite, and basalt. While heavy oxidation (Fe oxides) was observed between flow layers, hydrothermal mineralization was confined to small (<30cm) fractures within the flows. Figure 6 gives an example of a typical core box for well TG2.

In the basalt and andesite flows, fractures were oriented in 2 distinct directions: 1) generally subhorizontal (25 degrees off vertical) and 2) subvertical. The subhorizontal fractures were larger and more open, and often mineralized with sulfides (mostly pyrite and arsenopyrite), zeolites such as laumontite, and adularia and

Figure 6. Example of a typical 3.05m core box from well TG2 containing andesite (sections #1-11 in photo) and andesitic tuff (sections #11-15 in photo).

Figure 7. Core box showing the productive interval from TG2 (dark sections). Hot water at 359°F issued from a fractured and highly vesicular top of a basalt flow (sections #11-15 in photo). Note the darker color of the productive interval is because the rock remained wet for hours after core was pulled. Also note the mineralized subvertical vein in the rock just above the productive interval.

epidote at depths below ~187m . The subvertical fractures were very small (1-2 mm) and almost always mineralized with calcite and/or laumontite.

Secondary minerals in TG2 included abundant calcite, chlorite, laumontite and other zeolites, unidentified clays, secondary quartz, and sulfides (pyrite and arsenopyrite, rare cinnabar). Rare silica deposits were observed. Hairline suvbertical fractures were filled with laumontite or calcite. Above ~177.1m, the vugs in vesicular portions of the flows were filled with a combination of calcite and chlorite. Between ~177.1m and ~216.4m, the vugs in vesicular portions of the flows were filled with a combination of calcite, chlorite, epidote, and rare laumontite. The productive fracture at 178.31-178.92m had calcite, laumontite, chlorite, epidote, arsenopyrite, and cinnabar. Within the productive fracture and some vesicles below 177.1m, epidote displayed an interesting morphology, with radiating euhedral crystals nucleating on top of chlorite vein fill. Additional mineralized zones occurred at 210.3m and 214.9m, though the fractures in these zones did not appear to support large-volume fluid flow. Epidote and adularia were observed below 216.41m, though pyrite and other sulfides, and chlorite, continued below this zone.

Alteration minerals occurred interstitially, in fractures, in vesscles, and in contact zones and the tops of new flows. TG-4 was nearly completely "sealed," losing almost all its secondary (fracture) permeability to hydrothermal mineralization. Figure 9 shows an example of a relatively shallow fracture zone that has been sealed by hydrothermal mineralization. However, there are abundant high-temperature hydrothermal alteration minerals present in TG-4 core rocks, even at very shallow depths.A detailed analysis of the hydrothermal mineralogy is presently being conducted but the results were not yet available at the time of writing.

Slickensides observed in well rocks could be related to a possible range front fault on the SW side of the valley near well 4. This fault was identified from observations of terrace faulting up

Figure 8. Fractured zone from 56.39m-56.7m in well TG4. Fractures are filled with amorphous calcite, epidote, and sulfides (pyrite, arsenopyrite, and possibly cinnabar).

the hill to the SW, and lineations down-valley to the SW through the alluvial fans. A number of brecciated zones were observed in TG4 (Figure 9), but most were "sealed" with secondary mineral deposits and therefore probably do not represent active faults.

Figure 9. Brecciated fracture zone with secondary calcite deposit from a depth of 64.92m in TG4.

Geothermal Fluid Sampling and Geochemistry

Three water samples were obtained from the exploratory core holes. Two samples were obtained from well TG-2, with the first obtained from a fracture zone during well discharge. This production zone was subsequently cased off, and a second flow test of the well obtained samples from production zones between 189.9m and 253.9m MD, which was the completion depth of the core hole. The second core hole, TG-4, completed at 457.2m MD, encountered poor permeability conditions, and a sample of the fluids in the wellbore was obtained by flowing with an air assist.

Also in 2010, samples of steam condensate and non-condensible gas were obtained from fumarolic manifestations at the head of Hot Springs Bay Valley. These new chemical data augment previously available chemical data from samples of the hot springs and fumaroles that were collected in the 1980's and 1990's. A report with these data and updated geochemical interpretations of the resource is being prepared at the time of writing.

Discussion and Analysis of Preliminary Drilling Results

At the time of writing, only preliminary (unequilibrated) temperature gradient data is available for the Akutan TG wells. The equilibrated temperature gradient data is expected to be available in May, 2011.

Nonetheless, it is likely that a resource with similar temperatures to those measured during the drilling of TG-2 could support planned development on Akutan Island TG-2 encountered a shallow aquifer of 181.7 °C (359 °F) at very shallow depths of 178 m (585 ft.) Well TG4 did not encounter much fluid flow, and there was no real permeability (no open fractures) beyond ~335.28m, corresponding to a slowing of the temperature gradient at ~304.8m'. However, the overall temperature gradient in TG4 is anomalously high, indicating regional favorability for a developable resource, and suggesting a deeper, hotter, aquifer is present. Indeed, it is possible that the impermeable formations encountered between ~274.3m and TD at 457.2m in TG4 represent a "clay cap" that sits above a deeper, hotter system, perhaps the "upflow" resource. This interpretation correlates well with other data (e.g., MT resistivity data; see Kolker et al, 2010) which shows TG4 just barely penetrating a zone of increased resistivity that could represent the top of a geothermal aquifer. The upflow resource is estimated to be >220 °C (>430 °F). Alternatively or additionally, the presence of high-temperature hydrothermal alteration minerals that do not correspond to downhole temperatures may suggest that there was a prior hot alteration period that has come and gone. This is not atypical of large-scale, active hydrothermal reservoirs which often "self-seal" as the fluids fill all available fractures with mineral deposits. The earlier episode of hydrothermal activity could have produced hot springs reaching the present-day surface, because amethyst-filled vugs were observed as shallow as 6.1m in TG4. This interpretation would also account for the mercury and boron anomalies in the soil that were measured near TG4 during the 2009 geochemical survey.

A prediction of productivity of a production well drilled and completed to a similar depth as TG-2 can be made based on the preliminary results from drilling. Calculations were made concerning the possible productivity of Akutan TG-2, with the following assumptions based on observations at the wellhead:

1. The well is making two-phase flow.
2. 190 liters/min was measured at the surface.
3. A column of water from surface to the production zone at 178.31m-178.92m.
4. Only water was being produced from the fracture at 178.31m-178.92m where the fluid enters the 11.43cm hole.

The standard enthalpy formula was used to obtain the total mass flow at the surface. Prittchett's formula, an empirical calculation based on several geothermal field observations, predicts the deliverability of a full sized production well completed to a similar depth as TG-2 (See Appendix B for calculations). The outcome of these calculations was an extrapolated volume (in gallons per minute, or "GPM") for a production well. That number can be used to convert the GPM of the full sized well into MW using Ormat ORC conversion tables at 182 °C. These conversion factors are for ORC units manufactured by Ormat, Inc. There are other manufacturers of ORC turbo generators but all conversion factors are similar. In all probability a production well similar to TG-2 would be a well completed with 34cm, 54.5 ppf, K-55 buttress casing so that a 30cm downhole pump could be run in the casing and the well would be pumped. Water (brine) would be pumped to the surface and run through a Rankine cycle ("ORC") turbo-generator.

Pritchett's formula calculations yielded an extrapolated pumped capacity of the TG2 resource ranging from 465 to 820 gallons per minute (1760L/min – 3104L/min). Based on the Ormat conversion tables and above assumptions, it is estimated that a production well with the same flow characteristics as TG2 would produce 1.34 MW if completed near to TG2 up to a maximum of 2.38 MW.

Conclusions

The 2010 exploratory drilling program was successful in identifying a geothermal resource that would support the proposed development at Akutan. A resource of 181.67 °C was discovered at depths of less than 182.88m. Since volume could not be measured, calculations based on empirical geothermal field observations were used to predict the deliverability of a full sized production well completed to a similar depth as TG2. These calculations yielded an extrapolated pumped capacity of the TG2 resource ranging from 1760-3104 Liters per minute for a single larger-diameter production well. This means that a single production well with the same flow characteristics as TG2 would produce 1.34 MW up to a maximum of 2.38 MW. While the size of the outflow is not reliably constrained, the minimum size of outflow system appears to be about ~1000 x 500 m and may be as large as ~3500 x 1000 m based on magneto-telluric (MT) data. This suggests that the resource could support the drilling of multiple production wells, if necessary. Based on these assumptions, anywhere from 1 to 6 production wells will be required, depending on the size of the energy demand. One or more injection wells will also be required by the project.

Data from TG4 present some evidence for the possibility that even higher-temperature fluids exist at accessible depths in Hot Springs Bay Valley; this possibility will be explored by continued analysis of existing data, and during the drilling of the larger-diameter wells.