

EVALUATION OF THE MAKUSHIN GEOTHERMAL RESERVOIR,
UNALASKA ISLAND

Michael J. Economides⁽¹⁾, Charles W. Morris⁽²⁾,
and Don A. Campbell⁽³⁾

1. University of Alaska, Fairbanks, AK
Now with Dowell-Schlumberger, London
2. Republic Geothermal, Inc., Santa Fe Springs, CA
Now with Schlumberger Offshore Services, New Orleans, LA
3. Republic Geothermal, Inc., Santa Fe Springs, CA

ABSTRACT

Analysis of an extended flow test of well ST-1 on the flanks of Makushin Volcano indicates an extensive, water-dominated, naturally fractured reservoir. The reservoir appears to be capable of delivering extremely large flows when tapped by full-size production wells. A productivity index in excess of 30,000 lb/hr/psi implies a phenomenal permeability-thickness product, in the range of 500,000 to 1,000,000 md-ft.

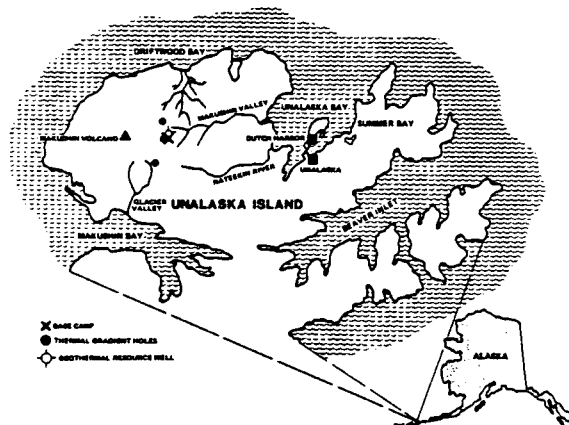
The flowing bottomhole (1,949-foot) temperature of the fluid is 379°F, which is lower than the measured static temperature at that depth (395°F). This phenomenon, coupled with an observed static temperature gradient reversal from the maximum 399°F observed at 1,500 feet, indicates that the reservoir proper is located some distance from the well. Presumably it is at a temperature slightly lower than 379°F and communicates with the wellbore via a high conductivity fracture system.

A material balance calculation yields an estimate of reserves that are capable of sustaining all of the present power needs of the island (13+ MW peak) with a geothermal power plant for several hundred years. Theoretically, a single large diameter well at the site of ST-1 could satisfy this requirement.

INTRODUCTION

Unalaska Island, located in the central portion of the Aleutian Chain has been the site of a multi-year exploration program for the evaluation of its geothermal energy potential (Figure 1). Makushin Volcano, the 6,680-foot high active volcano, situated on the northern end of the island, has a large number of surface manifestations, including several large fumarole fields.

FIGURE 1
PROJECT LOCATION MAP



Following extensive geological, geophysical, and geochemical surveys of the Makushin region, three ±1,500-foot temperature gradient holes were sited and drilled in the summer of 1982. The holes and their temperature gradients were described by Isselhardt, et al (1983a), who also provided a geothermal resource model of the Makushin geothermal area (Isselhardt, et al, 1983b).

The heat source of the Makushin geothermal system appears to be a buried igneous intrusion associated with the volcano. The temperature and post-glacial volcanic distributions suggest that the heat source for the system is not directly beneath the summit, but rather is offset to the east. The location of the Makushin producing horizon, a fractured diorite, appears to be structurally controlled by a major northeasterly striking fracture zone.

In the summer of 1983, a stratigraphic test well (ST-1) was drilled near one of the 1982 temperature gradient holes (E-1). A steam zone was encountered at 672 feet,

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followed by a significant fracture at 1,946 feet, where the drillstem dropped free for three feet.

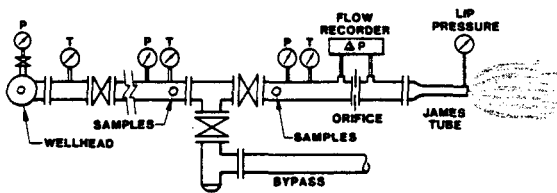
The 1983 well testing described by Campbell and Economides (1983) confirmed a highly prolific reservoir producing 47,000 lb/hr through three-inch pipe with little or no detectable pressure drawdown. Inadequately sensitive Amerada-type pressure instrumentation prevented rigorous analysis. A productivity index of over 3,000 lb/hr/psi and a permeability thickness of over 50,000 md-ft were inferred. A long flow test in the summer of 1984 was intended to provide a better estimate of these reservoir parameters as well as demonstrate sustained flow capability.

TEST FACILITIES AND INSTRUMENTATION

The surface equipment utilized during the 1984 testing was basically the same as that used in 1983 and described in the report by Campbell and Economides (1983). Figure 2 shows the surface equipment arrangements utilized during the long-term test of 1984. A relatively simple two-

FIGURE 2

MAKUSHIN WELL TEST EQUIPMENT



phase orifice meter and James tube were installed at the end of the flow line to measure the flow rate. Upstream and downstream orifice pressures were recorded simultaneously with a differential pressure flow meter. The James tube lip pressure was monitored continuously during the flow test utilizing both a test quality pressure gauge and a Barton pressure recording meter. In addition, the wellhead pressure and temperature were recorded continuously on Barton meters throughout the flow test. The orifice plate described above was utilized to calculate the enthalpy of the fluid using the empirical equation developed by Russel James (1980).

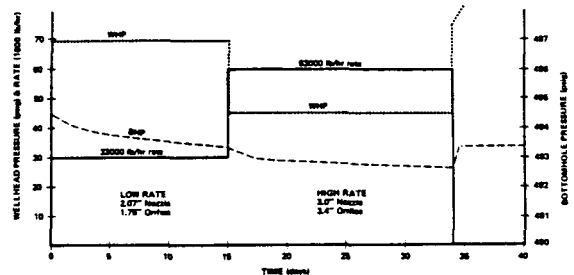
Downhole pressure and temperature measurements were obtained using two separate monitoring systems. The pressure monitoring equipment was a capillary tube system which utilized a gas filled, volumetric chamber downhole connected to a very small diameter capillary tube with a surface recording pressure transducer. This equipment was filled with helium gas as the pressure transmitting medium from the

bottomhole to the surface transducer. The equipment utilized in this test has an accuracy of approximately ± 0.3 psi, with a sensitivity of ± 0.1 psi on the transducer. The temperature measurements were obtained using a thermocouple cable system completely separate from the capillary tube. This required that the temperature data and the pressure data be acquired in separate runs in the well. The thermocouple was a chromel-alumel, grounded junction-type with an accuracy of ± 3 degrees F and a sensitivity of $\pm 3/4$ of a degree F. The thermocouple cable and the capillary tube were contained on two separate spools. As will be seen in the data discussed later, the pressure data and the temperature data were found to be quite reproducible throughout the flow test (unlike the prior years' data with Amerada-type instrumentation).

FLOW TEST MEASUREMENTS

The test of ST-1 consisted of two flow periods of approximately 33,000 lb/hr and 63,000 lb/hr each. The test rate/wellhead pressure/bottomhole pressure history is shown in Figure 3. The first flow period

FIGURE 3
MAKUSHIN ST-1 FLOW TEST
July-August 1984



lasted 15 days, while the second flow period at the higher rate lasted 19 days. During the 34 days of flow from ST-1, there were several minor changes in the flow rate and/or a bypass of the measuring system in order to perform sampling experiments or to modify the flow equipment. However, the test proceeded relatively smoothly, with the two flow rates being maintained at essentially constant conditions throughout their respective test periods.

Prior to the initiation of flow from ST-1, a static temperature profile of the wellbore was obtained on July 3 and a static pressure profile was obtained on July 4, as shown in Figure 4. These surveys clearly indicate that the well has a steam zone, with the vapor-liquid interface located at about 825 feet. This is shown by the constant temperature and pressure conditions existing in the upper part

of the wellbore until very near the surface (+200 feet). Below 825 feet there is a liquid zone which increases to a maximum temperature of 399°F at the 1,500-foot depth, then shows a slight decline to a temperature of 395°F at the bottom of the wellbore (1,949 feet).

FIGURE 4
STATIC TEMPERATURE (JULY 3, 1984)
AND PRESSURE (JULY 4, 1984) IN ST-1

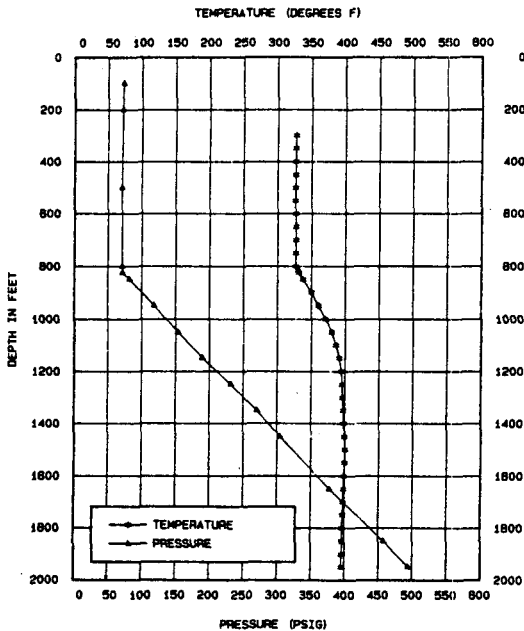
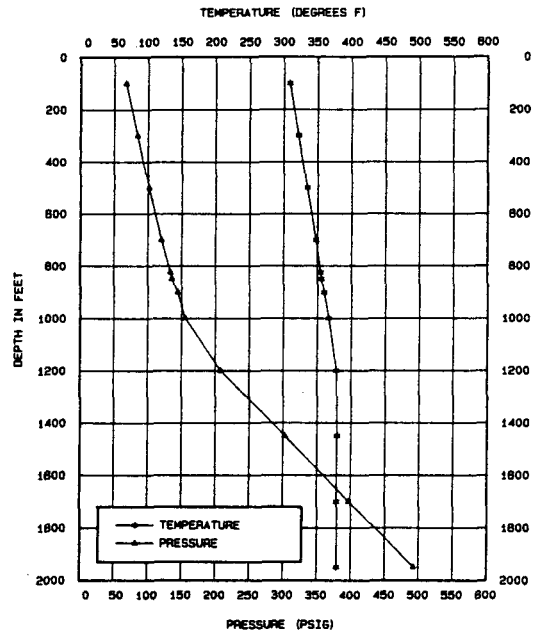


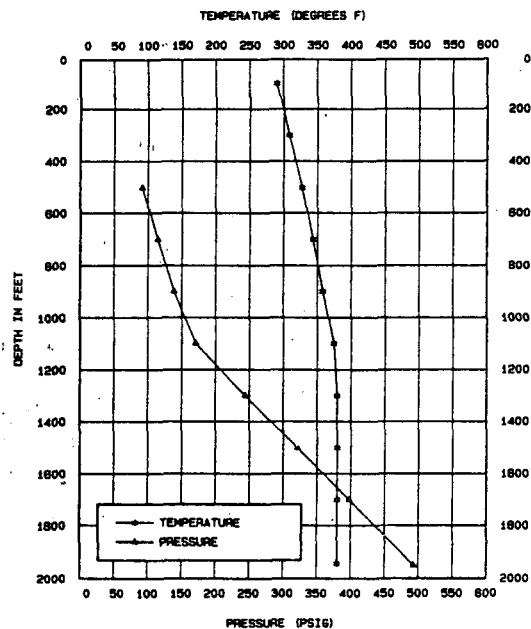
FIGURE 5
FLOWING TEMPERATURE (JULY 6, 1984)
AND PRESSURE (JULY 6, 1984) IN ST-1



down was observed during the 19-day high rate period. The well was shut-in on August 8, 1984, with the pressure tool hanging in the well at bottom. The pressure tool recorded buildup data for the next 17 days, showing less than one psi of increase in bottomhole pressure.

After flow was initiated on July 5, 1984, the well stabilized at a flow rate of about 33,000 lb/hr and this condition was maintained until July 20, 1984. During this flow period the pressure tool was left at the bottom of the well (1,949 feet), continuously recording bottomhole pressure, except for the times when wellbore pressure and temperature profiles were obtained. Flowing pressure and temperature profiles were obtained on July 6. The results are shown in Figure 5. A second set of pressure/temperature profiles were obtained on July 19, which were exact overlays of the July 6 profiles. About one psi of drawdown was observed over the 15 days at the low rate.

FIGURE 6
FLOWING TEMPERATURE (JULY 20, 1984)
AND PRESSURE (JULY 21, 1984) IN ST-1



Following the change in the flow to the higher rate of 63,000 lb/hr on July 20-21, another pressure/temperature profile was obtained (Figure 6). On August 7, 1984, a final pressure profile was obtained which was again an exact overlay of the July 21 profile. During the high-rate flow period, the pressure tool was again left at the bottom of the hole continuously recording bottomhole pressure except when profiles were run. An additional one psi of draw-

DISCUSSION AND INTERPRETATION OF RESULTS

Although the resolution of the pressure equipment during this test was far superior to that used during the 1983 test program, it was again found that the drawdown pressure response in ST-1 was extremely small, perhaps beyond the true sensitivity of the instrumentation. It appears that the pressure drawdown during the low-rate flow period was on the order of one psi, while the pressure drawdown in ST-1 during the high-flow rate was on the order of two psi. Thus, the productivity index derived from the two flow periods equals 31,000-33,000 lb/hr/psi. These values are very large (an order of magnitude more than the ones postulated in 1983), and indicate that the productivity of the Makushin reservoir is extremely high. Precise calculation of the permeability-thickness product is not possible with these data, although it is easy to infer that the value is phenomenally large (i.e., 500,000 to 1,000,000 md-ft).

Produced fluid enters the wellbore at the bottom of the well, 1,946-1,949 feet, at a temperature of 379°F, which is less than the static temperature in the wellbore at that level (395°F). This indicates that colder water is entering the well from some other area of the reservoir, probably shallower, along an unknown fracture path. After shut-in, the wellbore re-equilibrates to its static condition. Thus, the fluid density within much of the wellbore column lightens over a period of time as it returns to a higher static temperature. Because there is essentially only one inflow point, however, and pressure buildup was measured opposite this point, the re-equilibration of the wellbore fluid density should have no effect on the accuracy of the measured reservoir pressure. Therefore, the lack of full pressure recovery (only one psi rather than two) is not explained by thermal equilibration, but rather may be attributable to a real decrease in average reservoir pressure.

Well Potential

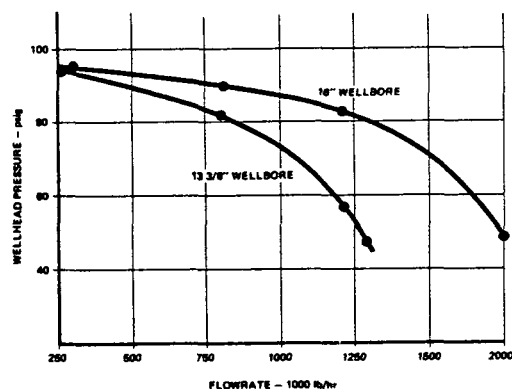
The estimation of individual well power potential for commercial operations requires the fundamental assumption that an extensive reservoir can be represented by the fluid properties, initial pressure, temperature, and productivity index derived from slim hole data such as that from ST-1. Given this as a basis, a wellbore flow model yielding wellhead pressure vs rate must first be validated against the measured slim hole conditions. Once a match is achieved, then wellhead pressure vs rate curves for various commercial-size wellbore configurations may be generated and related to appropriate power cycles with some degree of confidence.

The flow simulator used for this study was developed by Intercomp (1982) and has been used extensively by the industry for geothermal and geopressed wellbore flow calculations for several years. It is a vertical, multiphase flow simulator which incorporates treatment for variable well diameter with depth, heat losses, and noncondensable gases. The "nominal" commercial well conditions arrived at were as follows:

Initial Pressure = 494 psig at
1,949 feet
Inflow Temperature = 379°F at
1,949 feet
Salinity = 4,000 ppm TDS
CO₂ Content = 200 ppm
Productivity Index = 31,500 lb/hr/psi
13-3/8 or 16 inch Wellbore

Using these conditions, simulator-generated curves for wellhead pressure vs flow rate were constructed for the two different "commercial" wellbore sizes (Figure 7). At a reasonably optimum wellhead pressure of 60 psia (for power generation from this resource), a flow rate of 1,250,000 to 2,000,000 lb/hr is predicted, depending on wellbore size.

FIGURE 7
MAKUSHIN
COMMERCIAL SIZE WELL
PREDICTED FLOW RATE vs. WELLHEAD PRESSURE



Reserve Estimation Using a Material Balance Calculation

Material balance calculations for largely incompressible systems, such as the one at the Makushin geothermal reservoir, have been developed and used by a number of investigators in the petroleum literature. The initiating step is an expression providing the isothermal compressibility.

$$c = -\frac{1}{V} \frac{\partial V}{\partial p} T \quad (1)$$

Assuming that the total compressibility of the system is constant, Equation 1 may be integrated:

$$\frac{V_2}{V_1} = e^{c\Delta p} \quad (2)$$

and because the recovery in terms of reservoir volumes is defined as:

$$r = \frac{V_2 - V_1}{V_1} \quad (3)$$

then a combination of Equations 2 and 3 results in:

$$\frac{V_2 - V_1}{V_1} = e^{c\Delta p} - 1$$

The cumulative production in terms of reservoir volumes is, of course, $V_2 - V_1$ and, because the fluid is considered incompressible, the ratio

$$\frac{V_2 - V_1}{V_1} \quad (4)$$

may be taken as:

$$\frac{W_p}{W}$$

which is the ratio of the cumulative mass produced to the initial mass-in-place. Hence, Equation 4 becomes:

$$\frac{W_p}{W} = e^{(c\Delta p)} - 1 \quad (5)$$

Of the variables in Equation 5, W_p is the one known with certainty. In this case W_p is equal to:

$$W_p = 33,000 \times 15 \times 24 + 63,000 \times 19 \times 24 = 4.06 \times 10^7 \text{ lbs}$$

reflecting the two flow periods.

The variables contained in the exponential expression consist of the total compressibility of the system and the average reservoir pressure drop observed during the flow period. In this system, the total compressibility is the sum of the individual rock and fluid compressibilities.

$$c_t = c_w + c_f \quad (6)$$

Water compressibility is normally taken as $3 \times 10^{-6} \text{ psi}^{-1}$, while the compressibility of the rock could reasonably range between $2 \times 10^{-6} \text{ psi}^{-1}$ and $6 \times 10^{-6} \text{ psi}^{-1}$, depending on the lithology and the elasticity of the geologic features. For most reservoirs the value of the compressibility is taken as equal to $6 \times 10^{-6} \text{ psi}^{-1}$. This value will be used here with the

knowledge that it could be somewhat higher or lower.

The total observed bottomhole pressure drop at ST-1 during the 34 days of the flow test was less than two psi. The subsequent pressure buildup test resulted in less than one psi pressure gain. Both tests indicate an extremely large permeability-thickness product which is consistent with the small pressure differences observed. The total average reservoir pressure drop is assumed to be roughly one psi.

Using Equation 5, the initial-fluid-in-place may then be calculated:

$$\frac{4.06 \times 10^7}{W} = e^{(6 \times 10^{-6} \times 1)} - 1$$

yielding $W = 6.8 \times 10^{12} \text{ lbs}$. Given the uncertainties inherent in this calculation, the value of "W" can be considered order of magnitude only. Nonetheless, assuming a single full-size production well drilled on the site of ST-1 yielding 1,500,000 lb/hr (depending on the power cycle used it could generate 7-12 MWe), the longevity of this reservoir is extremely large relative to the needs of Unalaska Island (currently only about 13 MW peak). The calculated initial-mass-in-place could deliver this flow rate for over 500 years.

CONCLUSIONS

Results from the slim hole ST-1 flow test in 1984 confirmed the basic Makushin model of a shallow steam zone overlying a liquid-dominated reservoir in fractured diorite. A flowing temperature at 1,949 feet was found to be 379°F. This fluid appears to be entering the wellbore along a fracture which brings in colder water than would be expected by the 395°F static temperature of the fracture zone. The flow testing of the well in 1984 proved that the reservoir is potentially highly productive, even with only three feet of fracture interval open to the wellbore. Sustained flow through a three-inch diameter wellbore of 63,000 lb/hr was achieved with less than two psi of pressure drawdown from the initial pressure of 494 psi. This suggests a very large permeability-thickness value for the reservoir. The well productivity index obtained during this test was approximately 30,000 lb/hr/psi. Wellbore flow modeling indicates that commercial-size wells should be capable of one to two million lb/hr rates. A material balance calculation indicates a theoretical electricity reserve sufficient for the needs of the island for several hundred years at current consumption rates. In general, the data obtained during the 1984 flow test is consistent

with the results obtained during the short-term flow test of 1983, and confirms the existence of a substantial resource.

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ACKNOWLEDGEMENTS

The authors wish to thank the Alaska Power Authority for their support and numerous members of Republic's staff for their input to this report.