A Downhole Fluorimeter for Measuring Flow Processes in Geothermal and EGS Wellbores

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ABSTRACT

The conventional approach to measuring flow downhole in geothermal or EGS wellbores is through the use of a mechanical spinner tool, which makes use of a rotating paddle suspended and lowered (or raised) through the wellbore on a cable. But, such tools are notorious for failing-especially at high flow rates and at high temperatures. Likewise, non-uniform wellbore diameters greatly complicate spinner-tool data interpretation. An alternative approach to measuring flow rates in a geothermal or EGS wellbore is described. Making use of conventional tracer dilution methods, the tool is designed to work under both laminar and turbulent flow regimes. Volumetric flow rate measurement will allow the tool to accurately measure flow even through washout regions where borehole diameter varies. The tool is designed to be deployed on a single-conductor wireline and will be heat shielded. An optical fiber bundle will serve both to deliver the tool's excitation light signal and to return the emission signal from the fluorescent dye that will be introduced from a pump attached to the end of the tool. Temperature and pressure measurements will also be made using Resistance Temperature Detectors (RTD) and pressure transducers.

Introduction

Downhole temperature, pressure and flow rates are essential pieces of information for any geothermal field. Wire-line tools transmit data to the surface giving real-time readouts with depth. From the data logs fluid entry zones and temperature profiles of the wellbore can be obtained. Flow rates can be calculated and fluid entry zones can be interpreted in combination with temperature data. Temperature-Pressure-Spinner (TPS) tools are the current industry standard in obtaining this valuable information. TPS tools are fairly simple and straight forward instruments to understand and operate and can be manufactured to operate at high temperatures for extended periods of time (Davarzani 1988). When combined with caliper log data in combination with temperature and pressure data, TPS log data can be used to calculate volumetric flow rates.

As important as TPS tools are and how much valuable data they provide, there are limitations of TPS tools. TPS reliability relies on the velocity of water to turn a mechanical device on the tool. Flow rates that represent the two extremes in geothermal systems pose problems for TPS tools. Spinner tools typically need velocities in excess of 5 ft/min to turn the impeller element (Smollen 1996). Flow rates in the laminar flow range are not measurable. At very high flow velocities spinner tools may not be able to keep up with the velocity and the impeller itself may break off. The flow in between the two extremes may also require tools with differing impellers to accurately measure velocities. A second drawback to TPS tools is the inability to accurately measure flow in some open-hole or wash-out regions. If the tool is in a space of unknown diameter the velocity may not be used to accurately calculate the volumetric flow rate. The tool that is detailed in this paper is one that uses measured tracer concentration to determine flow rates.

Measuring flow through a pipe using tracing dyes dates to when Reynolds conducted his flow experiments in the late 1800's (de Nevers, 2005). Radioactive tracer tools have been employed for measuring flow in oil field injection wells (Smollen 1996). Radioactive tracers have the obvious drawback of using radioactive materials. For this reason radioactive tracing is used almost exclusively in injection wells. Most radioactive tracer tools do not measure concentration but rather are time of flight type tools that measure tracer pulses passing two different detectors.

The fluorescent tracers used for the application described in this paper need to be highly detectable and thermally stable. These compounds will additionally have to fluoresce at a wavelength where there is little interference coming from naturally occurring chemicals in the geothermal brine. Among the chief tracers being considered is fluorescein. Fluorescein has been proven to be highly detectable and thermally stable for use as a geothermal tracer (Adams et al. 1991). Other tracers that could be used include one in the family of naphthalene sulfonates (Rose et al. 2003), PTSA (Rose et al. 1998) or even quantum dot tracers (GTP 2010).

This paper describes a tool that will measure tracer concentration and calculate volumetric flow rates based on tracer dilution techniques. Using this approach, mass flow rate ($\dot{m}$) is calculated from the concentration of the tracer (X) and the rate at which the tracer is delivered (Q):

$$\dot{m}\left(\frac{m_{water}}{t}\right) = \frac{Q\left(\frac{m_{tracer}}{t}\right)}{\mathrm{X}\left(\frac{m_{tracer}}{m_{water}}\right)} \tag{1}$$

A volumetric flow rate can then be calculated using mass flow rate. Tracer dilution techniques have been successfully used for measuring flow in geothermal production wells at the surface for several years (Hirtz et al., 2001 and Lovelock, 2001). The design process of such a tool to measure and deliver tracers at geothermal conditions is the subject of the remainder of this paper.

Tool Outline

The tool will be capable of high temperature operation for extended periods of time and be able to deliver and measure water soluble tracer in the wellbore and to send information back to the surface in real-time. The tool will consist of a fiber optic at one end for detecting tracer, a tracer delivery system at the other end, and heat shielded electronics. It will be connected to a single conductor wireline that will serve as both the structural tethering element and communication element to the surface. At the surface the tool will be controlled by a computer that will be capable of sending and receiving instructions. The tool will also contain pressure and temperature measuring devices and log this information at the same time it is logging the tracer signal. A cartoon sketch is shown in Figure 1 below.

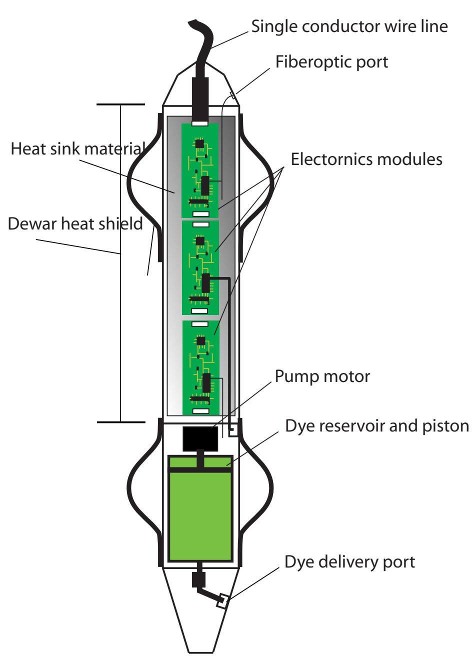

Figure 1. Sketch of the fluorimeter-flowmeter.

Flow Conditions and Tracer Mixing

Thorough mixing of the injected tracer within the wellbore is essential the accuracy of volumetric flow rates. Assuming an 8-inch well bore diameter calculations were made for several volumetric flow rates to determine the distance need to achieve 99% axial mixing in turbulent conditions. Calculation of mixing distance, L, was performed using Equation 2 listed below where f is the Fanning friction factor and is defined in Equation 3.

$$L = \frac{0.56D}{\sqrt{f}} \tag{2}$$

$$f = 0.001375\left[1 + \left(20{,}000\frac{\varepsilon}{D} + \frac{10^6}{\mathrm{Re}}\right)^{\frac{1}{3}}\right] \tag{3}$$

Equation 3 is only valid for turbulent flow, or flows for which Re is greater than 2,300. In Equation 3, D is the pipe diameter, which was assumed to be 8 inches, and ε is the surface roughness assumed to be the roughness of commercial steel pipe. Re is the Reynolds number and is defined as

$$\mathrm{Re} = \frac{4Q}{\pi D \nu} \tag{4}$$

where Q is the volumetric flow rate, D is the diameter and ν is the kinematic viscosity. Kinematic viscosity is a function of temperature and the fluid itself. In this case the fluid viscosity was assumed to be that of water and the viscosity at different temperatures was calculated. From these calculations a plot was constructed showing mixing length vs. volumetric flow rate. The Reynolds numbers ranged from 41,000 to 1.7×10^7. The plot is displayed below as Figure 2.

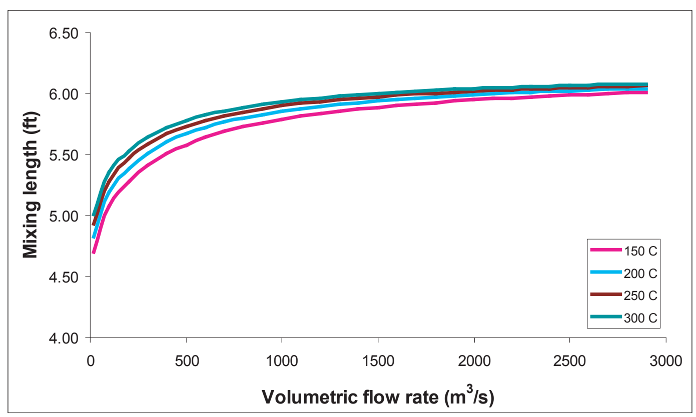

Figure 2. Mixing lengths required for complete axial mixing vs. flow rate.

From the plot one can see that the injection source and detection must be about 6 feet apart to approximate complete mixing even at very high flow rates (high velocities). The back mixing effect present in turbulent flow rates and present in most geothermal wells will ensure well mixed tracer provided the tool is longer than 6 feet.

The use of the tool at laminar flow conditions will be a challenge because of the lack of much back mixing inherent in the flow. Figure 3 below shows what tracer concentration across the wellbore might look like 8 feet from the injection source at different flow rates. As one can see from the plot, the tracer concentration would vary significantly from the borehole walls, at 1 and minus 1, to the center line.

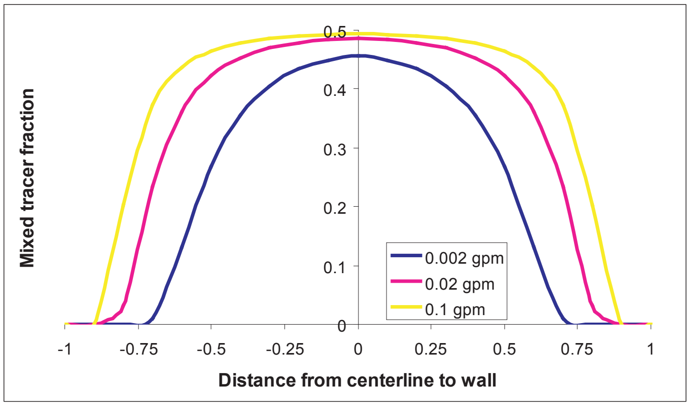

Figure 3. Tracer concentration profile across the wellbore at a distance of 8 feet from the injection point.

Operation at laminar flow regimes will require the addition of some sort of mixing device to provide for even mixing across the wellbore. Two of the ideas to help induce mixing include adding a piece that would have recirculation jets to induce back mixing or adding a mixing brush on the outside of the tool. Both of these options are depicted graphically in Figure 4 below.

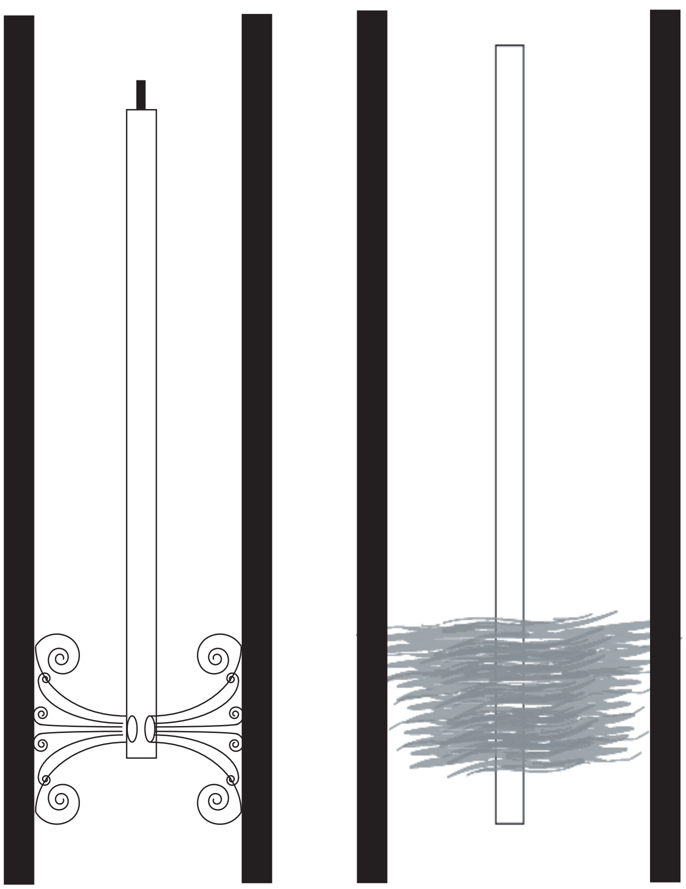

Figure 4. Cartoon representation of mixing devices, recirculation jets on the left and mixing brush on the right.

Temperature Effects

Perhaps the biggest challenge of deploying a tool in a geothermal wellbore is the high temperature. Using a Dewar-style heat shield in addition to a heat sink, estimates were made of the internal temperature of the tool as a function of time at geothermal conditions. With a stainless steel heat sink and an assumption of 5 watts of power dissipation within the tool, a plot of internal temperature versus time for several temperatures was produced and is shown below as Figure 5. Included in the plot are two lines that represent 85°C and 125°C. These two lines are significant because they show the temperatures at which traditional electronics (85°C) and automotive class electronics (125°C) will fail. The price increase to move from traditional to automotive grade electronics is not significant. Any electronics beyond these temperatures will need to be high temperature components that are available only at a significant increase in cost.

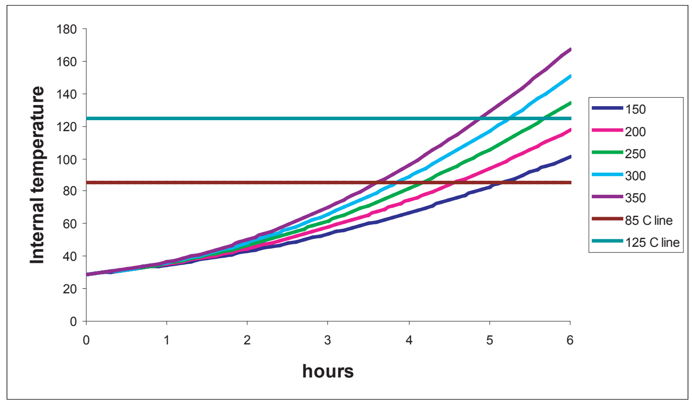

Figure 5. Expected internal temperature vs. time at various external temperatures.

From the plot it can be seen that use of automotive class components will allow for about 5 hours of operation at temperatures up to 300°C. To get to six hours of downhole operation at temperatures greater than 250°C it would appear that high temperature electronics would be called for.

In an attempt to extend the time that the tool can spend in the well, we investigated phase-change cooling. This entails the use of a low melting temperature alloy sealed inside the heat sink. Using

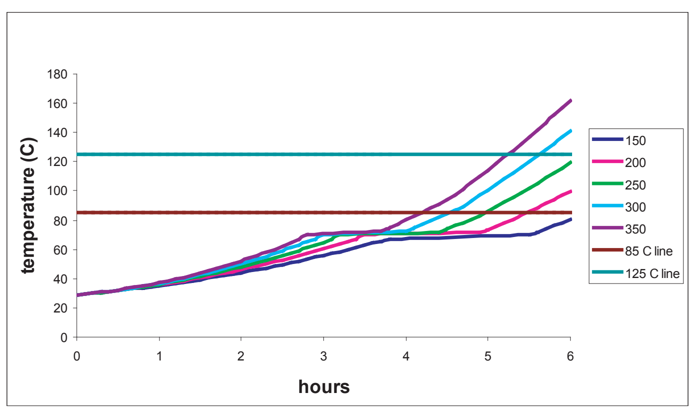

Figure 6. Expected internal temperature vs. time with heat sink that includes phase change material.

this approach, thermal energy would be expended in the phase change of the alloy and delay temperature rise. For comparison, calculations were performed with a low melt alloy, AIM 70, and the results were plotted as seen in figure 6 below.

From the plot it can be seen that the phase change material would elongate the tool's time in the well by approximately 30-60 minutes depending on the temperature. It is unlikely that we would opt to use this strategy in a prototype tool but it may be part of a future tool. Overall it appears that the main challenges for temperature management include limiting internal heat generation and designing with higher grade automotive components.

Electrical Components

The tool will be controlled by internal electrical components that measure and report tracer signal, temperature and pressure, and control power. These components will be either in the heat-shielded portion of the tool or at the surface. The electronics will be manufactured in a module form allowing flexibility and ease of repair. The added benefit of manufacturing in a module method is that if one module is not performing well it can be swapped out with a better designed module in future iterations of the tool.

Power Supply and Depth Encoder

The power supply will consist of two components. The first is regulation of the power delivered at the surface and the second is the regulation of power at the tool. The powersupply at the surface will convert AC to DC power sent down the wireline. The power supply at the surface will regulate voltage based on the power consumption in the tool and the resistance that is encountered in the line. Figure 7 below shows the relationship of voltage to power consumption with different line resistances encountered. The tool side power supply will be able to give real time information to the surface power supply to determine how much voltage to send.

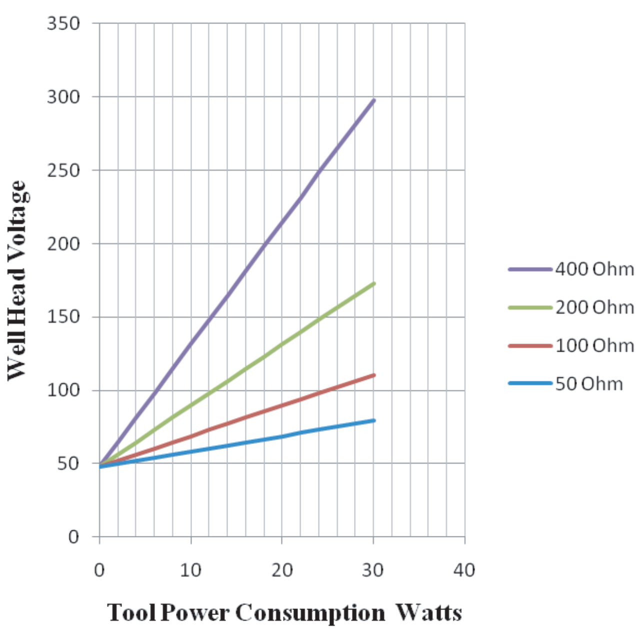

Figure 7. Well head voltage vs. power consumption with different line resistances.

The tool side power supply will involve input protection against over voltage and voltage converters to supply DC power at a variety of voltages to the various components. The power supply will also make use of real time supply optimization to request the right amount of power from moment from the surface supply. This should help to reduce the amount of heat that would be dissipated in the tool. A second strategy that will be used will be turning unused components off when they are not needed. For instance, when the tool is on the way to the zone of interest only intermittent temperature and pressure readings may be desired, the other components can be turned off to reduce internal heat generation.

In addition to supplying power along the wireline, the amount of line paid out will be used to calculate the depth of the tool at any given time. The controls at the surface will contain a depth-encoder device that will be able to accurately calculate the depth of the tool by counting the revolutions of the wireline spool. The depth information will be added to the pressure, temperature, and flow rate data.

Light Source and Detector

The light source is provisionally a high efficiency blue LED that will provide excitation at 465 nm and will operate at 125°C. The LED will be coupled to a collimator which will be connected to the fiber optic source. The LED operation strategy will include modulation to effectively subtract dark current as well as sampling the light to get an accurate indication of intensity out.

The detector will be a photo multiplier tube (PMT). Another detector that was considered was an avalanche photodetectors (APD). The advantages of the APD are low cost, ruggedness and a small electrical footprint. The disadvantages include low sensitivity and inability to operate above 50°C. In contrast the PMT has several orders of magnitude better sensitivity and can operate at temperatures up to 175°C. The disadvantages of PMT's include larger electrical footprint, high voltage (low current) operation and increased cost.

Pressure, Temperature and Inclination

The temperatures within the borehole and internal to the tool will be closely monitored throughout the test. A platinum RTD will be placed through one end of the tools sub-assembly and a second RTD will record temperatures within the tool body. Because some of the components could be destroyed by heat internal temperature will be measured as well. Pressure will be measured using a high temperature piezoelectric pressure transducer using a standard pressure filter port through the tools bottom sub-assembly. An accelerometer will be included in the tool to measure inclination and motion.

Tool Control and Data Transmission

In general much of the tool control will be located within the software being run at the surface monitoring station. Things that will be controlled will be the on/off of individual components, the LED intensity, the PMT gain and the flow rate of the dye pump.

Field Programmable Gate Arrays (FPGA) will be utilized in the communication through the wireline. The FPGA's will allow for flexible signals, in this case data will be packetized and sent with internal validation. Signal prioritization will be controlled by a CAN bus within the tool.

Test and Deployment Plan

The module design of the electronics will afford the ability to test each of the parts independently before attempting to test the tool as an entire unit. The electronics, fiber optics, pump and detector will be tested in autoclave reactors that will simulate geothermal pressures and temperatures. Once the individual components are tested a test fixture will be constructed to test the tool under flowing conditions. A long pipe with inlets at intervals along the length will serve as a test fixture. Water at a specified flow rate can be flowed through the pipe and then water will either be drawn off or added at a known flow rate through the inlets along the length of the pipe. The test fixture will be used to test the tool under flow conditions and serve as a calibration tool for the fluorimeter. Tests in the lab should reveal problems prior to a field test.

Conclusion

The design of a single-conductor wireline fluorimeter-flowmeter for geothermal applications is described. The tool will be useful under both turbulent and laminar flow conditions. Using high temperature electronics, the tool will be able to log well bores in excess of 300°C for periods of greater than 6 hours. It will provide the user with temperature, pressure and volumetric flow rates at each point along the wellbore.

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