The Iceland Deep Drilling Project: Fluid Handling, Evaluation, and Utilization

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Abstract

The prospect of producing geothermal fluids from deep wells drilled into a reservoir at supercritical temperatures and pressures is examined. Since these fluids, which would be drawn from a depth of 4000 - 5000 m, may prove to be chemically hostile, the wellbore and casing must be protected while the fluid properties are being evaluated. A scheme to achieve this by extracting the fluids through a narrow, retrievable liner is described. For the fluids thus produced to be superheated at the wellhead rather than existing in two phases, the reservoir temperature at 5000 m must be above 420 °C. If the wellhead enthalpy is to exceed that of conventionally produced geothermal steam, the reservoir temperature must be higher than 450 °C. A deep well producing from a reservoir with a temperature significantly above 450 °C might, under favorable conditions, yield enough high-enthalpy steam to generate 40 - 50 MW of electric power. This exceeds by an order of magnitude the power typically obtained from a conventional geothermal well. At this time, the extraction of chemicals from the thermal fluids is considered unlikely to be economically feasible. The cost of the fluid handling and evaluation program is estimated to be USD 5.5 million.

Keywords: *geothermal energy, supercritical fluids, wellbore flow.*

1 Introduction

The Iceland Deep Drilling Project (IDDP) is a program of geothermal exploration and technology development that aims to produce fluids for electric power generation and chemical processing from deep wells which tap reservoirs at supercritical temperatures and pressures. This long-term project is backed by a consortium of Icelandic energy companies looking to extend their resource base and improve the economics of geothermal energy utilization. Although the primary motivation for the project is economic, the consortium members are well aware of the potential scientific benefits of the project. They support efforts to conduct research on well fluids, rock samples, and reservoir properties.

Three geothermal fields, Krafla, Nesjavellir, and Reykjanes, are currently under consideration as candidate sites for deep drilling. The reservoir fluids encountered so far in Krafla and Nesjavellir are quite dilute, but those in Reykjanes are of seawater salinity. The preliminary design for the proposed deep wells calls for a cased upper part extending down to approximately 3500 m. The casing diameter will be 7", 7-5/8", or 9-5/8". Fluid would be produced from the deeper part of the well, which could initially be drilled with a coring tool to around 5000 m, and then reamed.

Nothing is known at this time about the physical or chemical properties of the fluids in the deep reservoir. These fluids may deposit scale upon depressurization and cooling, or they may corrode the casing. Hence, the processes by which the fluids may be produced and utilized can only be sketched in barest outline.

Numerous aspects of the proposed project have been addressed in a recently completed feasibility study. The results of this study have been presented in a three-part report published by Orkustofnun (Albertsson et al. 2003; Fridleifsson et al. 2003; Thórhallsson et al. 2003).

In this paper, which is one of five at this conference describing the Iceland Deep Drilling Project, we shall attempt to address some of the problems associated with bringing a very hot, chemically hostile, high-pressure fluid to the surface in order to study its properties effectively. Some aspects of the possible utilization of this fluid will also be outlined.

This attempt is necessarily very preliminary in nature.

2 The concept

When contemplating the initial production of a geothermal fluid of unknown chemical composition from a well drilled into an unfamiliar environment, one is presented with a dilemma. On the one hand, fluid must be extracted from the well for some period of time, even if only on a pilot scale, in order that its properties may be studied and an appropriate energy extraction process found. On the other hand, this very production may result in permanent damage to the well either because of corrosion of the casing or because of solid deposition in the aquifer or the wellbore. This was one of the problems facing the working groups of the IDDP at the first project meeting in June of 2001.

At that meeting, a concept emerged that soon came to be known informally as “the Pipe.” This approach to flow testing involves inserting into the well a narrow liner, about 4" in diameter, all the way down to a producing horizon. The fluid will be extracted through the liner, which thus serves to protect the wellbore and the casing from the effects of the fluid. The liner may be removed and replaced if serious scaling or corrosion problems arise.

Although its primary function is protection, the pipe can be made to play an important additional role. After some appropriate period of production, the liner may be removed and inspected, section by section. Such a direct study of the pipe should yield information on corrosion and scale formation over the entire range of temperature, pressure, and fluid phase conditions, provided that these are known as functions of depth. In this way, the pipe may be thought of as constituting the first phase of a pilot plant.

If the results obtained at this first stage of the fluid evaluation program are deemed encouraging, a wellhead pilot plant will be designed and constructed. Since nothing is known about the fluid properties at this time, even a preliminary design of such a wellhead pilot plant is considered premature.

3 Flow through the pipe

Though promising, the scheme outlined above immediately raises a number of questions. Can the fluid be produced through the pipe at all? In other words, will a steady flow of fluid through the liner, from a depth of 5000 m, sustain itself? Or will the pressure drop in the pipe conspire with the heat loss to the surrounding rock formation to kill the flow? And if the flow is sustainable, what will be the pressure, temperature, and fluid enthalpy at the wellhead? To address questions such as these, a computational model of the fluid flowing through the pipe was constructed. This wellbore simulator is very briefly described below, and the results of some calculations are presented.

In the model, the fluid enters a pipe with an inner diameter of 100 mm, at a depth of 5000 m, and flows towards the surface at the rate of 10 kg/s. The fluid in the model is pure water, with no dissolved minerals or gases. Of course, this choice represents a limiting best-case scenario, but it is one that can be evaluated with some confidence. Although some authorities have argued that fluids in geothermal systems at supercritical temperatures are likely to be heavily mineralized, there are others who believe that the pure-water model may provide a fair approximation to the fluids of the freshwater systems of Krafla and Nesjavellir.

The two basic equations of the wellbore simulator describe the rate of change with depth of the pressure and the enthalpy, respectively. The model takes account of friction in the pipe and heat loss to the formation surrounding the well. These equations are integrated in a stepwise fashion at intervals of 1 m. At each step, the temperature is computed from the pressure and the enthalpy at that point. For this purpose the model relies on equations for the thermodynamic properties of water and steam presented in the 1967 IFC Formulation for Industrial Use (see e.g. Schmidt and Grigull, 1979). The initial conditions for the calculations are the temperature and pressure at 5000 m depth.

Numerous well profiles were computed with this wellbore simulator program, starting with reservoir temperatures between 375 °C and 600 °C, and pressures between 230 bar and 300 bar.

At reservoir temperatures between 450 °C and 600 °C the wellhead pressure is expected to be virtually independent of the reservoir temperature, and roughly 90 bar lower than the reservoir pressure (Figure 1). At temperatures closer to the critical point, the wellhead pressure is sensitive to the reservoir temperature but almost independent of reservoir pressure.

The calculated wellhead temperature is approximately 70 °C – 140 °C lower than the reservoir temperature and essentially independent of reservoir pressure (Figure 2). The relatively high wellhead temperature may have implications for the choice of valves and wellhead materials.

The enthalpy of the fluid at the wellhead will be higher than that of steam from conventional wells only if the reservoir temperature is 450 °C or higher (Figure 3). This value is not very sensitive to the reservoir pressure.

If the temperature at 5000 m depth is higher than about 405 °C at 230 bar, or higher than about 422°C at 300 bar, the fluid produced will be superheated at the wellhead (Figure 4). At lower reservoir temperatures, a two-phase fluid will be produced at the surface. Such a condensation is undesirable, since it may lead to acid formation and corrosion. The water fraction of this fluid increases rapidly with decreasing reservoir temperature. It should be noted that the minimum reservoir temperature that will give rise to superheated steam at the wellhead is not very sensitive to pressure.

Using a wider liner will result in less friction, and a higher flow rate will reduce the heat loss per unit mass. If fluids are produced through a 9" inner diameter casing at a rate of 50 kg/s rather than a 4" liner at 10 kg/s, the threshold reservoir temperature for obtaining superheated steam at the wellhead drops by about 10 °C. If the reservoir temperature and pressure are high enough, the fluid may even be supercritical at the wellhead.

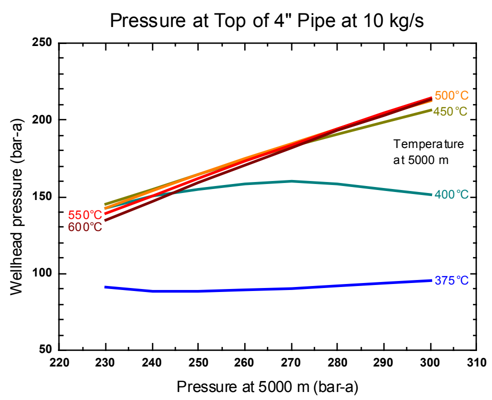

Figure 1. Wellhead pressure.

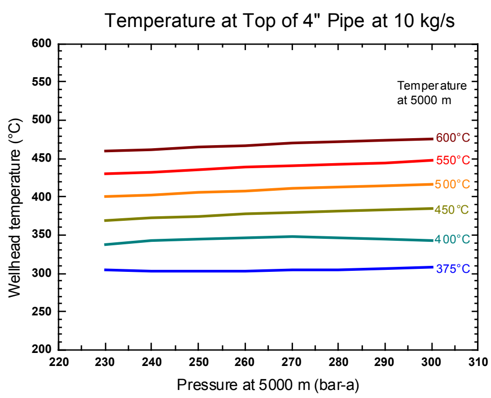

Figure 2. Wellhead temperature.

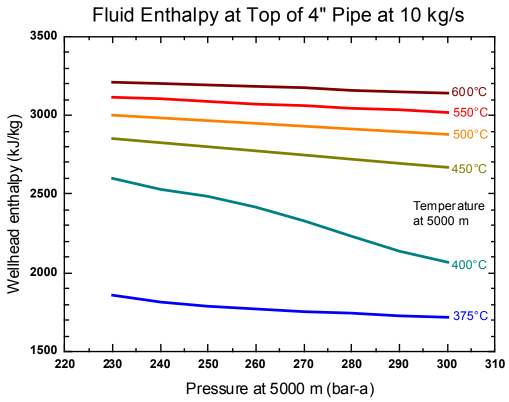

Figure 3. Wellhead enthalpy.

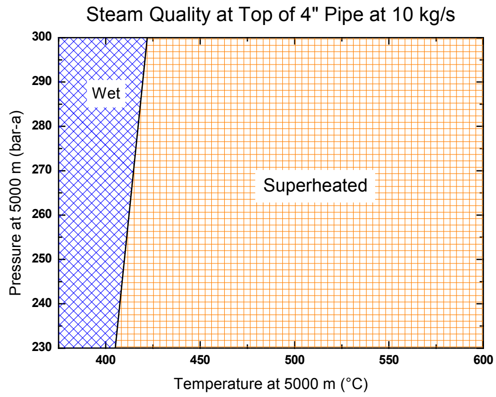

Figure 4. Wellhead steam quality.

The above analysis is based on the assumption that a steady flow of fluid through the pipe has already been established. Achieving this may not be trivial, however. Inductive heating of the pipe by means of an electrical coil has been sugested as a way to initiate the flow.

4 The pipe

The installation of a flow-test liner in an IDDP well and its subsequent operation are considered feasible. Figure 5 displays a schematic diagram of the pipe and the associated operating and measuring equipment. The liner will extend from the wellhead all the way down to the bottom of the production casing, where a valve will be installed. The purpose of this valve is to keep the deeper producing section of the well sealed off during periods when the pipe is not in place. This deeper part of the well will be left without a liner. The weight of the pipe will be supported from the top.

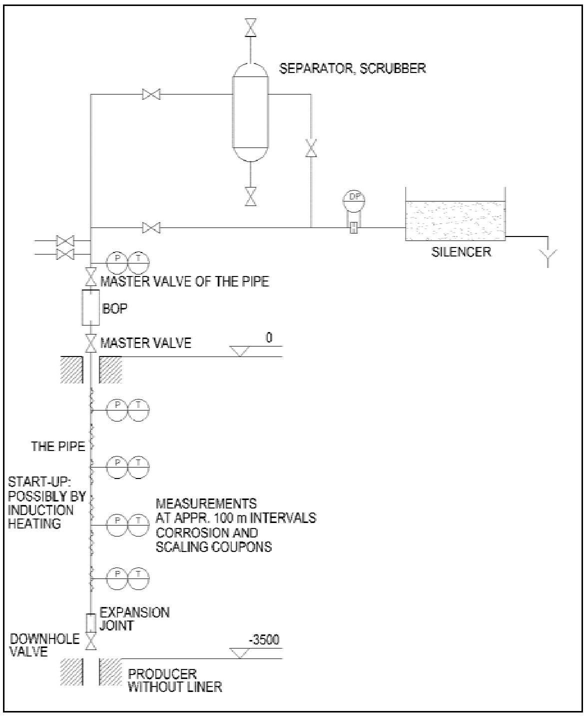

Figure 5. The pipe. Schematic diagram.

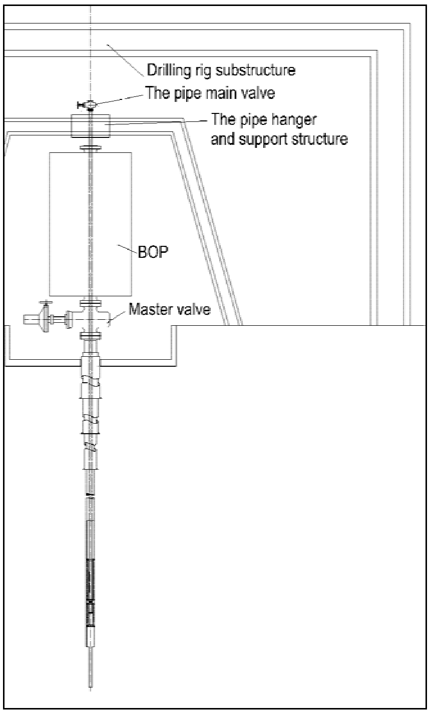

Figure 6. Pipe, wellhead, support structure.

The safe operation of the well at all times is a paramount consideration. Careful attention must therefore be given to wellhead design. In particular, blowout prevention equipment (BOP) identical to that used during the coring phase of the drilling should remain in place on the wellhead for as long as the pipe is in the well. Two master valves must be installed, one on the anchor casing and another on the pipe itself.

The master valve and the BOP are quite heavy, and a hanger structure above the wellhead is necessary to carry this weight (Figure 6). The structure, which could be a part of a drilling rig substructure, will also support a platform from which the pipe head can be accessed.

Some relatively simple equipment will be required to handle the fluid at the surface during the initial evaluation phase. This will include a separator, a silencer, and some associated piping. A more sophisticated pilot plant may be constructed at a later stage. Additional equipment for monitoring conditions in the pipe will be deployed downhole, in particular temperature and pressure gauges.

To facilitate the the operation of the pipe, a downhole valve should be emplaced at the bottom of the cased section of the well, where the narrower cored part begins. The purpose of this valve is to isolate the cased part of the well from the deeper producing part. The valve will be open only when the pipe is in the well and will be operated by a “stinger” on the end of the pipe. The stinger will open the valve as the pipe is installed. The end of the pipe will jut down through the valve, allowing room for thermal expansion of the pipe. When the pipe is removed, the stinger will close the valve as the pipe passes through. Although downhole valves are commercially available, these are not designed for the high temperatures expected in the IDDP wells. Thus, some development work is needed.

An expansion sleeve will be installed. This sleeve, which will allow the pipe to expand, will seal the annulus between the pipe and the casing from the high-temperature fluid.

Two ways of installing and retrieving the pipe have been considered. One is to employ a drilling rig positioned on the well. The other is to use a coiled-tubing system.

Any program of fluid evaluation involving the pipe must include at least the following:

- Continuous monitoring of the fluid mass flow rate
- Determination of the fluid chemical composition at different operating conditions
- Measurements of temperature and pressure in the pipe at certain depth intervals over a range of flow rates
- Analysis and measurements of any scale present in the pipe after retrieval
- Investigation of the resistance of prospective power plant materials to corrosion by the fluids.

The cost of installing the flow-test liner and operating it for a period of six months is estimated to be around USD 5.5 million. We expect the breakdown of the cost to be as follows. The pipe itself and the associated cables and sensors will be USD 1.5 million. Other materials such as the downhole and master valves, the wellhead, and assorted surface equipment comes to USD 1 million. The remaining USD 3 million is expected to cover BOP and lifting equipment rental, well monitoring, fluid and scale analyses, and contingencies.

5 Power generation

The high-temperature fluids expected from the IDDP wells offer two advantages over fluids from conventional wells for generation of electric power. One of these is the high enthalpy, which promises high power output per unit mass. The other is the high pressure, which keeps the fluid density high and thus contributes to a high mass-flow rate.

For a rough estimate of the electric power output that may be expected from an IDDP well, a comparison with a conventional geothermal well is instructive. A conventional well that produces dry steam only, at a wellhead pressure of 25 bar_a and a downhole pressure of 30 bar_a, will yield approximately 5 MW of electric power if the volumetric rate of inflow to the well is 0.67 $m^3\ s^{-1}$. An IDDP well tapping a supercritical reservoir with temperatures of 430 – 550 °C and pressures of 230 - 260 bar may be expected to yield 50 MW of electric power given the same volumetric inflow rate, 0.67 $m^3\ s^{-1}$. An IDDP well may thus afford a tenfold improvement in power output over a typical conventional well.

The physical and chemical properties of the fluid will determine the choice of technology that will be used for electric power generation. Until something is known about these properties, little can be said about the process options available. Nonetheless, it appears likely that the fluid will be used indirectly, in a binary system of some kind. In such a process the fluid from the well would be cooled and condensed in a heat exchanger and then injected back into the field. This heat exchanger would act as an evaporator in a conventional closed power-generating cycle.

6 Chemical processes

The high-temperature and high-pressure geothermal fluids expected from wells drilled into supercritical reservoirs may conceivably be put to uses other than electric power generation. Three possibilities will be considered below.

6.1 Conventional extraction of chemicals

Fluids produced from Icelandic geothermal reservoirs with temperatures exceeding 180 °C generally contain significant concentrations of noncondensible gases. These include carbon dioxide (CO_2), hydrogen sulfide (H_2S), and hydrogen (H_2). Small amounts of methane (CH_4), nitrogen (N_2), and argon (Ar) are also found.

The industrial demand for CO_2 in Iceland is currently met by a single geothermal well in the Grímsnes district. The export of industrial grade CO_2 is impractical. The high transport cost alone for this low-priced commodity precludes any serious consideration of such an option. Although technologies for the separation of H_2S and H_2 from the gas stream exist, the process cost would be high compared to the value of any sulfur, hydrogen, or sulfuric acid that might be produced.

The total concentration of most dissolved solids is quite low in both Krafla and Nesjavellir fluids. In Reykjanes fluids, the concentrations of most mineral components are comparable to those of seawater. As in all geothermal fields, silica constitutes an exception. A prefeasibility study of the extraction of silica from Nesjavellir fluids, commissioned by Reykjavik Energy, yielded disappointing results. A plant producing a low-sodium, high-potassium “health salt” from Reykjanes fluids has failed to turn a profit under several owners.

At this point, the extraction of chemicals from IDDP fluids thus appears unlikely to be economically feasible. This conclusion rests on the assumption that the fluid composition in the IDDP wells will not differ greatly from that of Icelandic wells drilled to date. Should the concentrations of valuable chemicals in fluids from the IDDP wells turn out to be significantly higher, the possibility of recovering these will be reconsidered.

6.2 Solution mining

High-temperature geothermal fluids can mobilize significant quantities of metals, particularly if the fluids are saline. This is dramatically demonstrated by the black smokers found on mid-ocean rifts. If the fluids from the IDDP wells indeed turn out to contain high concentrations of base or heavy metals, an interesting opportunity may present itself.

The group conducting this study has received an intriguing suggestion from researchers at the University of Manitoba who have been working on novel methods of solution mining (Daniel Fraser, private communication). They propose injecting cold water deep into the well to shock-precipitate minerals out of the fluid. The idea, in effect, is to create an artificial black smoker in the well. The precipitated minerals would be carried as a slurry to the surface and separated from the fluid at the wellhead for further processing. We hope by this scheme to prevent precipitation in the wellbore itself, which could plug the well. The abrasive action of the slurry during ascent might help keep the borehole or pipe wall free of scale. Much development work remains to be done, but if successful, this technology might be employed to mine significant quantities of metals.

6.3 High-pressure geothermal steam

Geothermal steam in Iceland is usually separated from the liquid phase at pressures of no more than 15 bar_a and temperatures less than 200 °C. Although adequate for turbine operation in electric power plants, this temperature imposes considerable constraints on the industrial utilization of the steam. Many chemical industries require steam with a condensation temperature of 250 – 290 °C for various drying and distillation processes. Coal-fired water-tube boilers represent the most common way of producing such steam, which has a pressure of 40 - 80 bar. The minimum price of this steam is roughly 7 - 8 USD per metric ton, though 10 - 13 USD/ton can be expected in many parts of Europe and the U.S. The steam from a successful IDDP well should thus be worth at least 7 - 8 USD/ton, which is two or three times the value of conventionally produced geothermal steam.

7 Conclusions

The production of initially supercritical fluids through a narrow flow-test liner inserted into an IDDP well is considered technically feasible. At 5.5 million USD, the installation and operation of such a liner for fluid evaluation purposes is by no means cheap, however.

The dilute fluids expected in the Krafla and Nesjavellir fields are considered less likely to present problems during flow testing and production than the more saline fluids expected in Reykjanes. From the standpoint of initial production and process development, it would thus be desirable if the first deep well were drilled in either Krafla or Nesjavellir. We hope, of course, to see all three sites drilled in due course.

8 References

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