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Drilling performance, injectivity and productivity of geothermal wells

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ABSTRACT

Drilling performance of 77 high-temperature production and reinjection wells in the Hengill Area in Iceland was analyzed. The results demonstrate that the perceived high risk of drilling in a proven field is less than commonly thought. No difference was found in the time required to drill holes of 13⅜″ or 9⅝″ production casing but the wider wells delivered 30–40% more steam. The average power output per drilled well amounts to 5.9 MW_e but 7.5 per productive well. To predict steam mass flow on the basis of the Injectivity Index one must consider reservoir conditions and enthalpy of the expected inflow into wells.

1. Introduction

After the successful development of the Nesjavellir Field in the Hengill Geothermal Area, about 20 km east of the capital Reykjavik in Iceland, Reykjavik Energy decided to explore other prospects in the area. In 2001–2011 the company drilled 55 production wells, 17 reinjection wells and five make-up wells in the Hengill Area. The majority of the wells were drilled with modern drilling rigs, up to four simultaneously, all-hydraulic with a top-drive and the large ones with automatic pipe handling. This intensive drilling period in the same geothermal area provided a unique source of data to obtain statistical estimates of the cost and effectiveness of geothermal drilling.

For geothermal power projects about 40–50% of the total investment cost lies in drilling of the production and reinjection wells and construction of the steam supply system for the plant. Current geothermal project costs for conventional flash-steam plants range between 2.8 and 5.5 million USD per megawatt of installed power with a medium of 3.9 (Gehringer and Loksha, 2012). Roughly half of the well cost is due to materials, infrastructure and services and the other half lies in the rental of the drilling rig and crew (day rates). Drilling each well to 2000–2500 m may take from 32 to 60 days. The cost of wells does thus critically depend on the effectiveness of drilling or the number of workdays.

A first attempt to analyze this data was undertaken by Sveinbjornsson (2010), followed by Sveinbjornsson and Thorhallsson (2012) and Thorhallsson and Sveinbjornsson (2012). This paper reports the main topics of these studies, with emphasis on the frequency of problems which led to excessive additional cost. The time breakdown in this study is based on daily reports prepared by Iceland GeoSurvey as the daily reports of the drilling contractors are confidential. The number of workdays to complete each of the four depth sections of the well was analyzed and the time broken down to show how much was spent on drilling, tripping, casing, cementing, logging, repair etc. The results were then grouped according to well design and technology applied. Cost calculations in this study are based on assumed prevailing prices for services and material, as the real cost was not made available. The study compares workdays for drilling holes with two different casing diameter programs, and two trajectories of vertical or directional drilling.

The Injectivity Index (kg/s)/bar in units of kilograms per second of flow per bar of pressure change is determined from completion tests at the end of drilling. The paper discusses Injectivity Indexes (II) and compares them to the well output obtained later by flow testing. Such estimates of future production are valuable for deciding whether to drill deeper, drill a sidetrack or to apply well stimulation before moving the drilling rig off the well.

While the results were obtained in Hengill Geothermal Area in Iceland, fields outside Iceland or with different geology and reservoir characteristics will have different risk levels, but the approach in this paper could lead to valuable comparisons.

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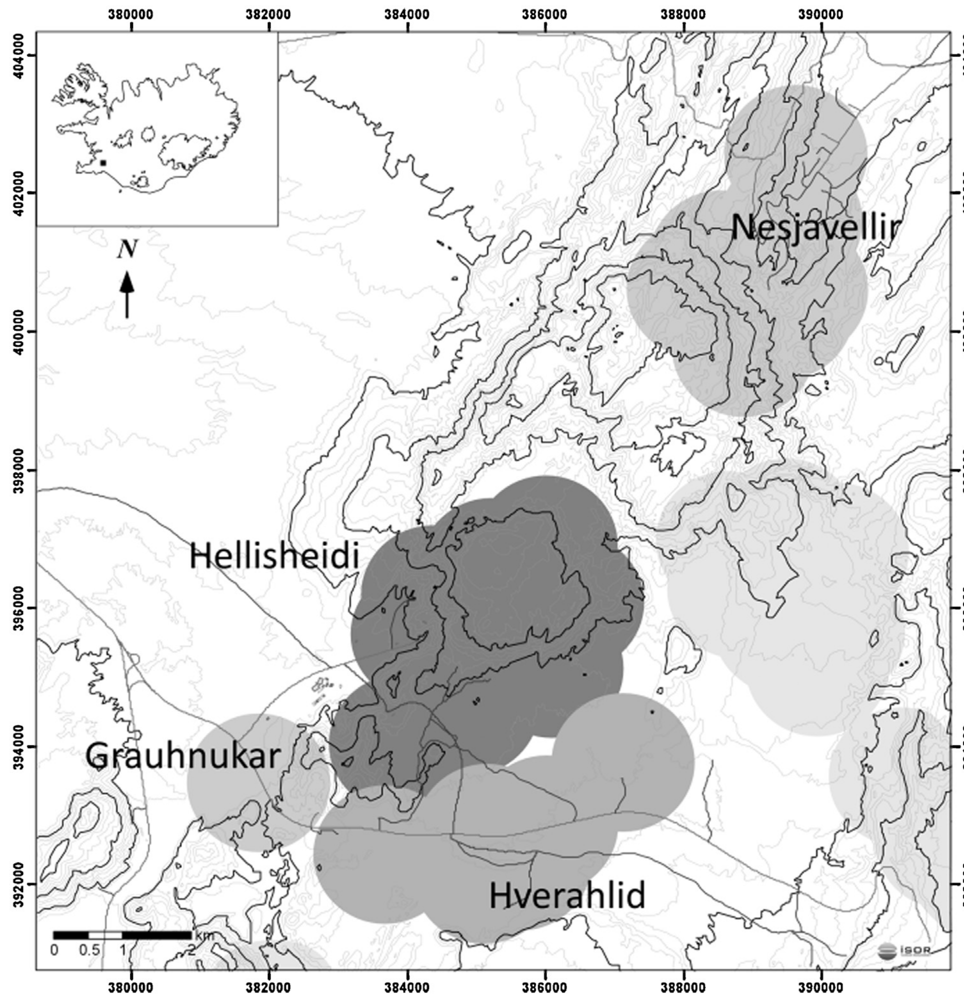

Fig. 1. Prospective fields in Hengill Geothermal Area. Most of the wells drilled in 2001–2011 were in the Hellisheidi, Grauhnukar and Hverahlid Fields. Figure from Iceland GeoSurvey (2012).

2. Drilling performance

2.1. Drilling in the Hengill Area

The conceptual model of the Hengill geothermal system was described by Franzson et al. (2010). Fig. 1 shows the drill fields of the Hengill Area.

Fig. 2 shows the distribution and trajectories of wells in the Hellisheidi, Grauhnukar and Hverahlid Fields as well as rock temperatures at 1000 m below sea level.

Two types of casing designs for high temperature wells of different diameters were used. Both types were either drilled vertically or directionally. The most common type in the Hengill Area is that of a directional well with a "large diameter" casing program. Fig. 3 shows an example of the design of a vertical well of regular diameter and a directional well of large diameter.

In the "large diameter" casing program the initial drilling (Section 0), pre-drilling, is by a small rig with a 26 inch (″) bit diameter down to 90 m for a 22½″ outside diameter surface casing. Then the large drilling rig is moved in. Section 1 is drilled with a 21″ bit to 300 m for the 18⅝″ anchor casing. Directional drilling starts with a kick-off point in Section 2, where the inclination is gradually increased by 2.5–3.0° per 30 m. Section 2 is drilled with a 17½″ drill bit to 800 m for the 13⅜″ production casing. The open hole in Section 3 is drilled with a 12¼″ bit to a depth of 1800–3300 m for the 9⅝″ slotted production liner. The other casing design is narrower and is called the "regular diameter" casing program. The depth sections are the same but the diameters are 18⅝″ for the surface casing, 13⅜″ anchor casing, 9⅝″ production casing, and 7″ slotted production liner.

Seven drill rigs of Iceland Drilling Ltd. were used in the drilling effort. Two small rigs with a hook-load capacity of 50 tonnes (t) were used for the initial drilling to 90 m depth. An intermediate size rig (100 t) was used for the shallow sections (1 and 2) of a few wells. Four larger rigs (179–300 t) of the type shown in Fig. 4 were used for the main drilling.

The initial drilling was performed with air hammer and foam or tricone bits with tungsten carbide inserts, using mud and water as circulation fluids. Rotary drilling techniques with tricone bits were applied in Section 1 from 90 to 300 m depth, but in Section 2 from 300 to 800 m depth a mud motor was used to rotate the bit and a Measurement While Drilling (MWD) tool inserted in the drill string to monitor the direction (azimuth) and inclination of the well. In Section 3 from the 800 m production casing to the total depth no mud was used but drilling was carried out with water only as long as there were no severe circulation losses. Most wells were then switched over to aerated water by compressed air for pressure balance until the total depth was reached.

2.2. Temporal analysis of drilling data

To compare the drilling time for different wells, the respective numbers of workdays were normalized for a reference well of that