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Cost analysis of oil, gas, and geothermal well drilling

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ABSTRACT

This paper evaluates current and historical drilling and completion costs of oil and gas wells and compares them with geothermal wells costs. As a starting point, we developed a new cost index for US onshore oil and gas wells based primarily on the API Joint Association Survey 1976–2009 data. This index describes year-to-year variations in drilling costs and allows one to express historical drilling expenditures in current year dollars. To distinguish from other cost indices we have labeled it the Cornell Energy Institute (CEI) Index. This index has nine sub-indices for different well depth intervals and has been corrected for yearly changes in drilling activity. The CEI index shows 70% higher increase in well cost between 2003 and 2008 compared to the commonly used Producer Price Index (PPI) for drilling oil and gas wells. Cost trends for various depths were found to be significantly different and explained in terms of variations of oil and gas prices, costs, and availability of major well components and services at particular locations.

Multiple methods were evaluated to infer the cost-depth correlation for geothermal wells in current year dollars. In addition to analyzing reported costs of the most recently completed geothermal wells, we investigated the results of the predictive geothermal well cost model WellCost Lite. Moreover, a cost database of 146 historical geothermal wells has been assembled. The CEI index was initially used to normalize costs of these wells to current year dollars. A comparison of normalized costs of historical wells with recently drilled ones and WellCost Lite predictions shows that cost escalation rates of geothermal wells were considerably lower compared to hydrocarbon wells and that a cost index based on hydrocarbon wells is not applicable to geothermal well drilling. Besides evaluating the average well costs, this work examined economic improvements resulting from increased drilling experience. Learning curve effects related to drilling multiple similar wells within the same field were correlated.

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1. Introduction

1.1. Importance of this work

The chemical energy contained in hydrocarbon fluids found in sedimentary rock formations is the biggest source of US primary energy. Less commonly used geothermal energy is a thermal energy contained in the Earth's crustal rocks and fluids filling these rocks. Geothermal resources are renewable (Sanyal, 2005), bigger, and more widely distributed than fossil fuels (Tester et al., 2006). Traditionally, low prices of hydrocarbon resources have limited development of geothermal systems to hydrothermal areas, where a rare combination of high temperature fluids at shallow depths filling porous and permeable host rock existed. Recently, increased costs of hydrocarbon resources exploration and a shift towards low-emission technologies has created potential for geothermal energy to become a national scale source of baseload power (Tester et al., 2006). For this to occur, it would require the development of both high grade hydrothermal systems and geothermal resources in the form of Enhanced (or Engineered) Geothermal Systems (EGSs) that require some level of stimulation to be productive.

In both conventional hydrothermal systems and EGS, production and reinjection wells are drilled to a depth where sufficiently high rock temperature is encountered. In hydrothermal systems, in-situ fluid is extracted to the surface using a production well. Thermal energy carried by the geothermal brine is converted into electricity or used directly as heat in surface facilities. After releasing a fraction of its thermal energy, geothermal fluid is typically reinjected into a reservoir to maintain the production rate. If the geothermal formation has insufficient permeability, EGS methods including hydraulic stimulation can be used to create or open a network of interconnected fractures. In EGS, water is pumped down the injection well, circulated through the reservoir, and recovered to the surface using a production well. While passing through the EGS reservoir, water extracts the thermal energy stored in hot rocks. The energy extraction process in EGS is known as heat mining or heat farming (Fox et al., 2013).

Economic feasibility of geothermal projects strongly depends on drilling expenditures. Well completion costs typically contribute to 30–60% of the total capital investment in hydrothermal power plants (Blankenship et al., 2005; Tester et al., 2006) and can exceed 75% for medium- and low-grade EGS (Petty et al., 2009). Drilling determines not only the cost, but also the risk associated with geothermal projects. Consequently this leads to higher importance of well drilling analysis. The cost calculations should generally be performed on an individual well basis. In addition to this, with sufficient statistical information, we can create correlations representing average well drilling and completion costs. Such correlations for both hydrocarbon and geothermal wells are presented in this report. They can be used for general feasibility studies, economic comparisons with other energy sources, and for designing cost-effective power conversion systems.

Well drilling is an experience-based activity, so drilling multiple similar wells in the same field is likely to result in improved drilling performance and lower costs. Faster drilling in terms of overall penetration rates may be a consequence of optimized drill bit selection, better insight into the site's lithology, personnel training or simply elimination of past mistakes. Since well drilling and completion is usually the most expensive single component of both production of hydrocarbon fuels and geothermal energy, any cost improvements due to learning are meaningful and worth analyzing. Thus, we also included an investigation of the application of the learning curve theory to drilling activities.

1.2. Previous work

Various aspects of geothermal drilling have been analyzed in the past. Recent work is focused primarily on emerging drilling technologies (Rowley et al., 2000; Blankenship et al., 2005; Tester, et al., 2006; Thorsteinsson et al., 2008) and drilling and completion of EGS wells (Tester et al., 2006; Polsky et al., 2008; GEECO et al., 2012). A comprehensive overview of the geothermal drilling research activities was provided in 2010 by the U.S. Department of Energy (U.S. DOE, 2010). DOE report summarizes research programs in years 1976–2010 which had the biggest impact on geothermal drilling and logging technology, including particularly relevant to this study geothermal well models and cost models.

Costs associated with geothermal well drilling and completion have been analyzed to a low level of detail compared to hydrocarbon drilling. Many methods exist for evaluating drilling costs of oil and gas wells that include a treatment of complexity. These include, but are not limited to Joint Association Survey (JAS), Mechanical Risk Index (MRI), Directional Difficulty Index (DDI) and Difficulty Index (DI) (Kaiser, 2007). The geothermal industry has not developed such analysis tools yet and the main focus so far has been on correlating drilling costs with well depth.

Historically, it is believed that there have been over 4000 geothermal wells drilled worldwide (Sanyal and Morrow, 2012), but their costs have rarely been published due to proprietary nature of the data. Furthermore, even if cost data were available the number of geothermal wells drilled each year is insufficient to evaluate drilling costs and their uncertainties as a function of well depth to a reasonable of statistical confidence (Augustine et al., 2006; Mansure et al., 2006; Tester et al., 2006; Mansure and Blankenship, 2008). Because of similarities between hydrocarbon and geothermal drilling processes, drilling cost trends for oil and gas wells have been commonly used to normalize the costs of geothermal wells drilled in the past to the current year (Augustine et al., 2006; Tester, et al., 2006; Mansure et al., 2006; Mansure and Blankenship, 2008; Polsky et al., 2008; Sanyal and Morrow, 2012).

Several such drilling cost trends have been developed. A well cost index first created by Tester and Milora (Milora and Tester, 1976) and later refined by Herzog and Tester (Tester and Herzog, 1990) allowed for comparison of the historical costs of drilling hydrothermal, EGS, and hydrocarbon wells. The index was used to convert the costs from nominal to real dollars, which provided a common basis for comparison. The cost trend was based on JAS database of U.S. onshore oil and gas wells. Augustine et al. (2006) as a part of the 'Future of Geothermal Energy' assessment (Tester et al., 2006) expanded Herzog and Tester's analysis up to 2003. The new well cost index named MIT Depth Dependent (MITDD) index assigned a separate trend to each of nine well depth intervals listed in the JAS.