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Heat extraction and power production forecast of a prospective Enhanced Geothermal System site in Songliao Basin, China

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ABSTRACT

As a promising advanced technology, Enhanced Geothermal System (EGS) utilizing deep geothermal energy has gained increasing attention. Production performance of a prospective EGS site in Songliao Basin was evaluated through mathematical modeling. Firstly, numerical simulation of heat extraction process in the fractured reservoir was carried out. To take account of the flow process in wellbores, reservoir-wellbore coupled simulation was undertaken through indirect coupling of TOUGH2 with the wellbore simulator HOLA, in which dynamic treatment of the wellbottom pressure was enabled. Power production performance was then investigated through thermodynamic modeling of an electricity generation system using the output from the reservoir-wellbore coupled simulation. The results suggest that the desirable thermal efficiency and gross power output could be obtained initially, whereas the decrease in production arising from thermal depletion of the reservoir is significant at later stages of operation. Meanwhile, the power consumption of the injection pump takes up an increasing amount of the generated power. It can be inferred from the comparison between simulations with and without coupling that a downhole pump could improve the hydraulic performance notably with little sacrifice of the thermal performance.

1. Introduction

Being exploited for direct use, electricity generation and ground source heat pumps, geothermal energy plays an important role in alleviating the pressure of energy supply and improving the ecological environment [1–3]. To promote development of the extensive geothermal energy resources, advanced technologies such as exploitation of hot dry rocks, magma bodies and geopressured reservoirs have aroused increasing interests nowadays [4–5]. The concept of EGS involves mining heat from hot dry rocks via pumping cold fluid to the targeted formation through the injection well, and bringing hot water from the production well, then utilizing the hot water to generate electricity. Stimulation treatment by creating artificial fluid flow pathways before production is usually performed to enhance the well injectivity and productivity of the low permeability geothermal reservoir. Compared to conventional geothermal resources, EGS is considered feasible for widespread use with fewer environmental issues [6–7].

Many scientific and industrial communities have been working on the development of EGS projects over the last 20 years. Among various approaches, numerical simulations which can provide detailed and complete information about the reservoir response and wellbore performance during production were performed to provide references throughout the course of exploration, construction and operation [8–11].

For characterizing and simplifying the practically complex fracture system properly, primarily two methods were employed in simulation, the discrete fracture network method and the equivalent continuum method [12]. The former is able to analyze the fracture orientation, size, spacing, etc., while the latter treats the discrete fracture system as a continuous porous medium with lumped porosity and permeability. As illustrated in Ref. [13], when assuming 10^{-12} m^2 of permeability for the reservoir, the Darcy

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velocity is 0.2 m/year at maximum. In most studies, the average permeability of a fractured reservoir is, for example, 0.038×10^{-12} m^2 in Ref. [14] and 10^{-12} m^2 in Ref. [15], estimated to be around or lower than 10^{-12} m^2. Accordingly, fluid transport in the reservoir is quite slow. It is reasonable to use the multiphase extension of Darcy's law to describe fluid advection in the reservoir, especially when information for determining the discrete fracture network is incompletely understood.

Another issue associated with modeling the subsurface process of EGS is to incorporate the wellbore flowing. When using the reservoir simulators, only the porous region between the bottom of injection well and that of production well could be modeled [16], not including conduits between the wellhead and the wellbottom as flowing within the wellbores does not obey Darcy's law. Pruess et al. [17] have estimated the surface area between a 4000 m deep 8″ well and the surrounding formations to be over 5000 m^2, a number that approaches heat transfer areas of major fractures in an EGS. Previous studies on wellbore heat transfer showed that the effect of heat exchange with the surroundings on temperature is significant in the first few days and diminishes over time [17–18]. Thus, the adiabatic condition was often applied to simulations of several decades of operation [19–20].

When modeling the porous reservoir without considering the wellbore components, input data for the bottom of both the injection well and the production well, including injection rate and enthalpy, flowing wellbottom pressure for production, were roughly estimated and fixed [8–9,19,21–22]. Some other studies prescribed the production rate at the bottom of production well [15,23], but in reality it is unfeasible if there is no experiment to determine it, especially in the presence of water losses [6]. While in the reservoir-wellbore coupled simulation, only parameters at the wellhead are required as input data, omitting the necessity of the wellbottom estimations and enabling dynamic treatment of the wellbottom conditions. In this study, TOUGH2 is used to solve the governing equations in the porous reservoir [16]. As for the non-Darcy flow in the wellbores, it is dealt with by using the wellbore simulator HOLA. HOLA is coupled with TOUGH2 to account for the variation of wellbottom pressure during operation. The deliverability model derived from the Darcy seepage model for single well radial flow is employed to determine the mass flow by productivity index and pressure difference between the reservoir and the wellbottom.

To evaluate the production performance of an EGS system, both the hydraulic and the heat transfer aspects were investigated in literature. Pruess [19–21] calculated the net heat extraction rate as the difference between the produced enthalpy and the injected enthalpy. For feasibility study of an EGS site, power production evaluation is necessary and straightforward. Assuming that all heat produced is used for electrical power generation, the power output was calculated as the product of a presumed utilization factor and exergy of the heat extracted in Ref. [9]. In this study, a 3d conceptual model of a potential EGS site is established. Field data obtained by early geological survey is used for defining the model and calibrating the natural state calculation. Then, thermodynamic modeling of a binary power generation system is carried out to get more detailed insight into the overground power generation process. In the binary unit, geothermal heat is transferred to a working fluid with low-boiling point because direct use of the geothermal fluid in a power conversion cycle is not efficient from a thermodynamic point of view [24]. The Kalina cycle (KC) [7] is chosen simply to demonstrate how to evaluate the overall power output basing on the output of the reservoir model. Additionally, auxiliary power required for delivering the geothermal fluid from the reservoir is estimated as this portion of power might be innegligible with respect to the net power output [24].

2. Model description

2.1. Reservoir model and wellbore model

2.1.1. Geological background

The studied area lies in Shuangcheng Fault Depression, north of Songliao Basin, China. As shown in Fig. 1, Shuangcheng Fault Depression is controlled by four main ‘s’-shaped faults stretching toward near north north-east. It is divided into central Duiqing Uplift and two secondary depressions, Yinshen Depression and Shuanchen Depression along the faults. The square region bounded by blue lines in Yinshen Depression in Fig. 1 (in web version) is the area opted for modeling as detailed geological information for that area is available and the land surface there is suitable for drilling and building geothermal power plants. Different colors in Fig. 1 represent the thickness of formations deposited during the faulting period, including Yingcheng Formation, Shahezi Formation and Huoshiling formation from top to bottom. The maximum thickness in Yinshen Depression is 2479 m, and the deepest basement of the faulting period lies in −6250 m from the land surface.

Dimensions of the modeled area are 9000 m, 6000 m and 6000 m in x, y and z direction, respectively. Two exploratory wells exist in the region, YS1 and YS2. Geometry of YS2, together with the vertical distribution of stratigraphic units is shown in Fig. 2 [25]. Among the stratum in Fig. 2, Nenjiang Formation, Yaojia Formation, Quantou Formation and Denglouku Formation constitute the sediments of the depression period, and Yingcheng Formation belongs to the sediments of the deep faulting period.

2.1.2. Layer settings

Based on the stratigraphic data from well logging of YS2, the model is set to have five different geological layers. The upper succession of the depression period including layer A and layer B in Table 1, extends from the ground surface to 3600 m in depth, and is composed mainly of sedimentary rocks like siltstone and sandstone. The lower succession of the deep faulting period includes layers C, D and E. Layer C constitutes the high temperature reservoir, corresponding to Yingcheng Formation in Fig. 2, while layer B and layers D, E the cap and basement of it. Layer C is composed mainly of volcanic rock intercalated with clastic rock. The rock type in layer B is mainly block sandstone, silty mudstone, and flysch deposition of sandstone intercalating with conglomerate. Layers D and E constitute the local caprock and the source rock of the fault depression.

As the formation dip angle is shallow, in the present study, horizontal heterogeneity is not considered. Each layer is simplified to be uniform and treated as single-porosity, isotropic porous medium, and variation only exists in the vertical direction between different layers. Vertical interval and rock properties derived from the geological survey of each layer are given in Table 1. Generally, in this area, rock grain density and permeability increase with depth and porosity decreases with depth.

2.1.3. Boundary conditions of the reservoir

Due to the large scale of the model, it is assumed that no mass and heat flow across the lateral boundaries.

Typically, the top surface was fixed at atmospheric pressure and annual average temperature, a constant heat flux was applied at the bottom surface for maintaining the temperature gradient [26–27]. Being lack of these data, the temperature and the heat flux were continuously adjusted while comparing the temperature field obtained from the natural state simulation with the measured temperature data. Simulation results showed that the top surface temperature mainly affects temperature values at the upper part of the model, while the heat flux mainly determines the temperature