Geothermics 74 (2018) 135–149

Contents lists available at ScienceDirect

Geothermics

journal homepage: www.elsevier.com/locate/geothermics

Field observations at the Fenton Hill enhanced geothermal system test site support mixed-mechanism stimulation

Jack H. Norbeck[a,*], Mark W. McClure[b], Roland N. Horne[a]

[a] Department of Energy Resources Engineering, Stanford University, Stanford, CA 94305, USA
[b] McClure Geomechanics LLC, Palo Alto, CA 94305, USA

ARTICLE INFO

Keywords:
Enhanced geothermal systems (EGS)
Shear stimulation
Hydraulic fracture propagation
Induced seismicity
Reservoir geomechanics
Renewable energy

ABSTRACT

The Fenton Hill enhanced geothermal system (EGS) test site was the first of its kind, and interpretations of field observations from the project have influenced the past four decades of EGS development. In this study, we hypothesized that stimulation (i.e., permeability enhancement) in the Fenton Hill reservoir occurred through a mixed-mechanism process that involved propagation of hydraulic splay fractures encouraged by the stress changes induced as natural fractures opened and failed in shear. We used a hydromechanical fractured reservoir numerical model to validate the efficacy of the mixed-mechanism stimulation conceptual model. Our modeling results were consistent with the observations recorded during the Fenton Hill field experiments in three distinct ways: (1) a marked increase in injectivity occurred at a threshold injection pressure, (2) the near wellbore injectivity enhancement following each stimulation treatment was reversible, and (3) seismicity propagated in a direction that was inconsistent with the orientation of the maximum principal stress, despite injection having occurred at pressures significantly above the fracturing pressure. The modeling results demonstrate that several independent hydromechanical observations could be replicated by the mixed-mechanism stimulation conceptual model. In contrast, the observations could not be explained by a pure mode-I hydraulic fracture propagation nor by pure shear stimulation. Distinct fracture sets are activated through the mixed-mechanism stimulation process; the natural fractures provide most of the heat transfer surface area, and the tensile splay fractures form the bulk of the fluid storage volume. Future EGS projects could take advantage of mixed-mechanism stimulation to design wellbore completion and reservoir engineering and strategies to increase effective transmissivity, improve heat mining efficiency, and extend useful reservoir lifetime.

1. Introduction

The Fenton Hill enhanced geothermal system (EGS) test site, located in New Mexico, USA, was the first EGS project in the world (Brown et al., 2012). Major accomplishments of the project include successful hydraulic stimulation of two deep wells creating a flow connection, fluid circulation through the geothermal reservoir for several months, and generation of electricity. The original design of the geothermal heat exchange system was similar to the conceptual model studied by Gringarten et al. (1975). In this idealized stimulation strategy, a set of vertical hydraulic fractures would connect two deviated wells. Initial attempts at hydraulic stimulation were unsuccessful at connecting the wells, however, and microearthquake event locations indicated that an unanticipated region of the reservoir had been affected. A hydraulic connection was made possible by redrilling each of the wells through the cloud of microseismicity and performing several additional stimulation treatments (Brown et al., 2012). To explain the unexpected behavior, the scientists and engineers involved in the project developed two competing hypotheses of the hydraulic stimulation mechanism (Brown et al., 2012; Duchane, 1991). Observations that injection pressures exceeded the magnitude of the least principal stress and pressure-rollover behavior suggested that planar hydraulic fractures were forming in the reservoir. In contrast, the development of a broad cloud of microseismicity that migrated predominantly in a direction that was inconsistent with the expected orientation of a planar hydraulic fracture for the *in situ* stress state suggested that perhaps permeability enhancement was caused by shear slip on preexisting fractures.

In the present study, we investigated how fracture pressurization, poroelastic stress, and thermal stress affected the stimulation process and the evolution of microseismicity that was observed during various injection experiments carried out during the 1980s. We analyzed multiple data sets to develop a conceptual model of the Fenton Hill EGS fractured reservoir system, focusing on four stimulation treatments in

* Corresponding author at: Earthquake Science Center, U.S. Geological Survey, Menlo Park, CA 94025, USA.
E-mail address: jnorbeck@stanford.edu (J.H. Norbeck).

https://doi.org/10.1016/j.geothermics.2018.03.003
Received 19 December 2017; Received in revised form 19 February 2018; Accepted 5 March 2018
Available online 19 March 2018

Well EE-2 leading up to and including the massive hydraulic fracture (MHF) experiment (Expts. 2018, 2020, MHF prepump, and Expt. 2032). Our preliminary investigations were first presented by Norbeck et al. (2016a,c).

We hypothesized that the dominant process contributing to enhanced reservoir permeability during hydraulic stimulation could be characterized as a mixed-mechanism stimulation process. Mixed-mechanism stimulation has been described previously by Weng et al. (2011), McClure (2012), McClure and Horne (2013a, 2014), Jeffrey et al. (2015), and Zhang and Jeffrey (2016). In the mixed-mechanism stimulation conceptual model, a combination of several hydromechanical processes can influence permeability evolution. In particular, opening-mode deformation and shear-induced dilation can influence a fracture's hydraulic aperture. Furthermore, both opening and sliding deformations can promote the formation of splay fractures that initiate and propagate off of natural fractures (Norbeck and Shelly, 2018; Pollard and Fletcher, 2005; Ye and Ghassemi, 2018; Zhang and Jeffrey, 2016). For application to geothermal reservoir stimulation, the mixed-mechanism process has the potential to generate a fracture network that could be beneficial for thermal recovery due to its relatively complex geometry compared to pure hydraulic fracturing or pure shear stimulation (McClure and Horne, 2014; Jeffrey et al., 2015).

In this work, we present evidence that a mixed-mechanism stimulation process occurred in the Fenton Hill geothermal reservoir by using a numerical reservoir model to replicate several distinct behavioral characteristics observed during stimulation at Fenton Hill. Because subsurface reservoir engineering data at this site are insufficient to describe the system with certainty, it is possible to develop multiple hypotheses that can explain the observations. In Section 5, we analyze several alternative conceptual models that cannot be ruled out completely, but that we believe are unlikely.

The remainder of this paper is organized as follows. In Section 2, we present our conceptual model of the Fenton Hill reservoir and describe the field data and observations used to constrain the model. The hydromechanical numerical model used in this study is described in Section 3. Results from our mixed-mechanism simulations are presented in Section 4. In Section 5, we propose several alternative hypotheses and discuss why we believe they are unlikely. In Section 6, we discuss the implications of the mixed-mechanism process for reservoir engineering design of future geothermal projects. Our concluding remarks are listed in Section 7.

2. Background on Fenton Hill and model constraints

The EGS experiments at Fenton Hill involved many field tests in both the shallow Phase I and deeper Phase II reservoirs. The primary hydraulic stimulation experiments in the Phase II reservoir took place in Wells EE-2 and EE-3A, which each had openhole intervals at a depth of roughly 3.6 km. The most significant stimulation treatment was performed in Well EE-2 during December 1983 (Expt. 2032, also called the Massive Hydraulic Fracture (MHF) treatment), in which roughly 21,000 m^3 of water was injected over 60 h at a maximum flow rate of 106 kg/s and maximum wellhead pressure of 49 MPa (Brown et al., 2012). We considered the following stimulation treatment experiments in Well EE-2:

- Expt. 2018 (July 1982)
- Expt. 2020 (October 1982)
- Expt. 2032 prepump (December 1983)
- Expt. 2032 massive hydraulic fracture (December 1983)

The injection rate and injection pressure data recorded during these experiments are shown in Fig. 1 (the data were reformatted based on the data reported by Brown et al. (2012)).

Los Alamos National Laboratory provided microseismic event locations and timing recorded during Expts. 2032 (MHF) (White et al., 2015, 2016, 2017). Fig. 2 shows the event locations recorded during Expt. 2032 (MHF) in plan and cross-sectional views. Events migrated away from the well during injection. In plan view, the microseismic cloud tended to migrate in an overall NNW-SSE direction. This unanticipated observation helped to form the basis for our conceptual reservoir model. Fig. 3 illustrates the rate of migration of the seismicity away from the wellbore. During the injection treatment, events tended to occur across the entire stimulated region. Upon shut-in after 60 h of injection, the events occurred predominantly at the edges of the stimulated region. Following shut-in, the event rate decayed steadily over the period of about one day.

2.1. State of stress

Our interpretation for the state of stress in the Phase II reservoir was based on wellbore stress measurements (Barton et al., 1988), earthquake focal mechanisms (House et al., 1985), minifrac tests (Brown, 1989; Kelkar et al., 1986), and observations during step-rate injection tests (Brown et al., 2012; Matsunaga et al., 1983). Varying estimates of the fracture gradient are available in the literature. Kelkar et al. (1986) summarized a large number of minifrac tests, illustrated in Fig. 4, to estimate that the minimum principal stress gradient was 19 MPa/km, implying that the minimum horizontal stress was σ_h = 68.4 MPa at 3.6 km depth. However, Kelkar et al. (1986) noted that tests shallower than 3.3 km depth indicated a much lower fracture gradient. Based on these observations, Brown (1989) proposed that the minimum principal stress gradient was 13 MPa/km, implying a minimum horizontal stress of σ_h = 46.8 MPa at depth. Brown (1989) hypothesized that due to the high tensile strength of granite, hydraulic fractures were unable to form at the wellbore, so the fracturing pressure observed during injection tests corresponded to the pressure required to exceed the normal stress on preexisting fractures intersecting the well. If these fractures were oblique to the principal stresses, then their opening pressure would have been greater than the minimum principal stress. Similar behavior has been observed during other field-scale stimulation treatments (Baisch et al., 2015) and pressurization experiments in wellbores with preexisting fractures (Baumgartner and Zoback, 1989; Rutqvist and Stephansson, 1996). Therefore, Brown (1989) proposed that the apparent increase in fracturing pressure at 3.3 km was caused by a discontinuity in natural fracture orientation rather than stress, and that the tests shallower than 3.3 km reflected a more accurate measure of the minimum principal stress. Focal mechanism analysis indicated both strike-slip and normal faulting mechanisms, suggesting that the maximum horizontal stress was roughly equal to the vertical stress (Barton et al., 1985; House et al., 1985; Fehler, 1989; Phillips et al., 1997).

The state of stress used in our hydromechanical reservoir simulations can be summarized in Figs. 4 and 5. We assumed that the “low stress” profile was an accurate reflection of the state of stress at Fenton Hill. The orientation of the maximum horizontal stress was N30°E based on interpretations of wellbore breakouts from acoustic borehole televiewer logs (Barton et al., 1988). Brown (1989) stated that the reservoir fluid pressure was about 5 MPa subhydrostatic, which has been taken into consideration in the stress state representation shown in Fig. 5.

2.2. Geologic structure

Microseismic events observed during hydraulic fracturing treatments are often interpreted as shear slip events on natural fractures that surround the main hydraulic fracture (Warpinski, 2009; Warpinski et al., 2012). At Fenton Hill, if this was the appropriate mechanism, then the microseismic cloud would be expected to migrate in the direction of maximum horizontal stress (N30°E), but this was not the case. Irrespective of the assumption about the low- or high-stress profile, injection pressures during the hydraulic stimulation treatments often exceeded the magnitude of the minimum horizontal stress significantly (see Figs. 1 and 4), which would suggest that hydraulic fractures were