

First Hydraulic Stimulation in Fractured Geothermal Reservoir in Pohang PX-2 Well

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ABSTRACT

The first hydraulic stimulation for enhanced geothermal system (EGS) development in Korea had been conducted in the PX-2 well of 4,348 m depth in Pohang EGS site from January 29th to February 20th, 2016. Treatment histories of injection rate, wellhead pressure and corresponding induced microseismicity data were obtained from the stimulation test upon 140 m long open hole section at the well bottom. Wellhead pressure was up to 89 MPa and considerable level of flow rate was attempted up to 47 L/sec. Microseismicity observation showed a trend of larger and more frequent seismicity occurrence in shut-in phase than in injection phase. The injectivity index during the stimulation periods had increased as 2.7 times in January 30th at the wellhead pressure of 73 MPa. Postulating the existence of a major fracture zone intersecting the open hole section, the transmissivity and the corresponding equivalent aperture of the fracture were evaluated. Required breakdown pressures by hydrofracturing and hydroshearing mechanisms were estimated based on the various scenarios on the in-situ stress condition, major fracture zone orientation and shear failure criteria.

1. INTRODUCTION

The first enhanced geothermal system (EGS) development project in Korea was launched at the end of 2010 in Pohang. Five boreholes are located within 5 km from the site (Fig. 1): BH-1 of 1.1 km depth, BH-2 of 1.5 km depth, BH-3 of 0.9 km depth, BH-4 of 2.4 km depth, and EXP-1 of 1 km depth. The Pohang EGS site is owned and operated by NexGeo Inc., and it is located at 129°22'46.08"E, 36°06'23.34"N. Drilling of PX-1 and PX-2 wells were finished with final depths of 4,127 m and 4,348 m, respectively, and it is planned to be expanded to a triplet system, i.e., a fluid circulation system with three wells in the target reservoir, after stimulations in PX-2 and PX-1.

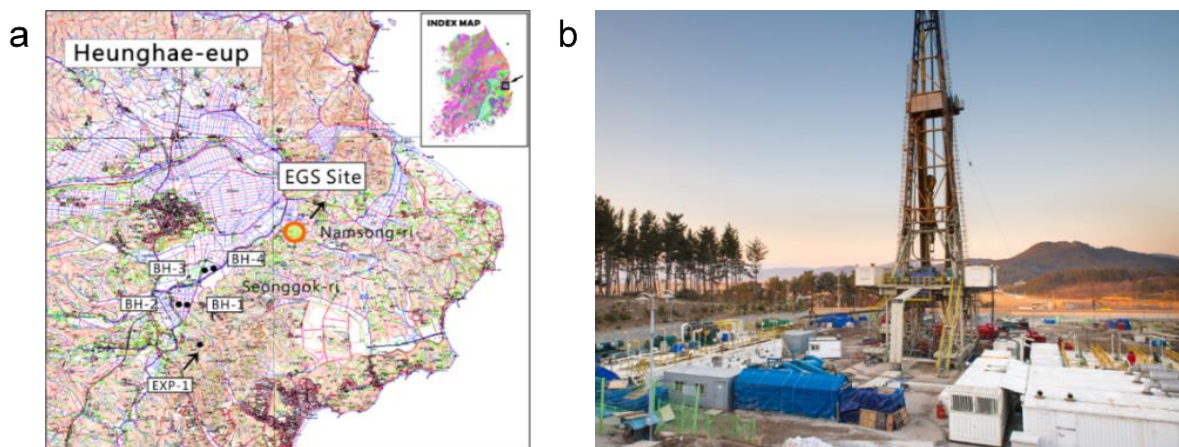


Figure 1 (a) Locations of Pohang EGS site and five boreholes near the site; (b) whole view of Pohang EGS site

For the geology of Pohang site, the formations can be classified into four layers from upper to lower as: Tertiary sedimentary rocks, Tertiary volcanic rocks, Cretaceous sedimentary and volcanic rocks, and Permian granitic rock formations. The uppermost surface is mostly covered with semi-consolidated mudstone and the reservoir at the target depth of 4.3 km is mainly composed of granodiorite and granitic gneiss (Fig. 3 (a)). In terms of the fracture zones, a major lineament is expected to exist with 20°~30° dip direction and 65°~70° dip, intersecting or closely locating with the 140 m long open hole section of PX-2 well (Fig. 2 (b)).

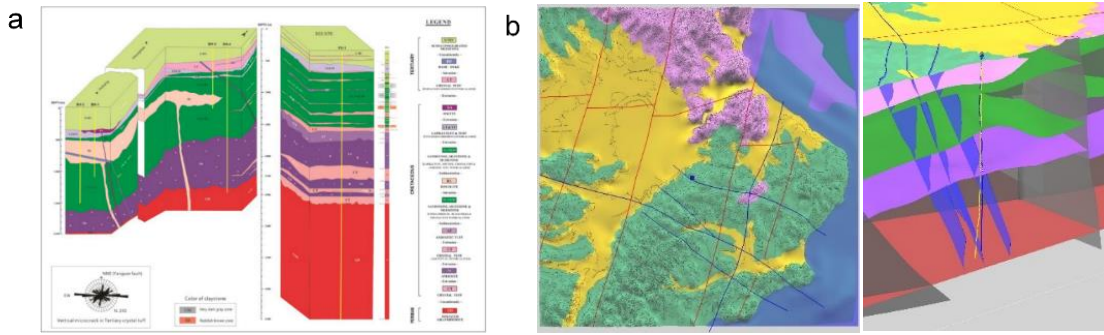


Figure 2 (a) 3D geological map including BH-1-4 and PX-1 (Lee et al., 2015); (b) major fracture zone near the site

The first large-scale hydraulic stimulation for EGS development in Korea had been conducted in Pohang PX-2 well to characterize the physical properties of the target reservoir and to induce the actual fracture propagations that can improve the reservoir permeability. Stimulation had been conducted from Jan 29th to Feb 20th 2016 and 1,970 m³ of water had been injected into the reservoir through 140 m long open hole section located at the bottom of PX-2 well. Water was used as the injection fluid in this period, and it was supplied from an irrigation reservoir about 300 m far from the site. Four main pumps had been used for fluid injection during the stimulation with maximum 8,000 water horsepowers for each; the maximum capacities were 105 MPa for wellhead pressure and 4.5 m³/min (= 75 L/sec) for flow rate, respectively. Induced seismicity had been captured by the seismicity observation system composed of nine borehole seismometers, four surface seismometers and one three-component borehole geophone installed at 1,360 m depth of PX-1 well.

2. OBSERVED STIMULATION DATA

The observed stimulation data for wellhead pressure, injection rate and microseismic event amplitude is shown in Fig. 3. During the stimulation period, the maximum wellhead pressure reached 89.2 MPa (= 131.8 MPa bottomhole pressure) and maximum flow rate recorded 46.8 kg/sec (= 2.81 m³/min). The largest seismic event occurred in Feb 2nd and its magnitude was about M_w1.4. In the first day of stimulation (January 29th), pressure decrease during the continuous injection was observed at the wellhead pressure of 67 MPa.

Various attempts were made in terms of the injection strategies, such as step rate increase and decrease, cyclic injection, long term injection, long term shut-in, sudden high-rate injection and bleed-off. An interesting trend was found that the number and amplitude of seismic events in the shut-in phases were larger than that of the injection phases. During the microseismicity observation, the daily peak amplitudes occurred in the shut-in phases except Jan 29th ~30th and the maximum peak amplitude occurred in the longest shut-in phase.

Interpretation of the observed data (Fig. 3) may require a few notes. First, the data shown in the figures have one second of time intervals for every line graphs, except the wellhead pressure observations manually recorded during the longest shut-in period (Feb 4th ~ Feb 11th) and plotted with a line-symbol graph. Second, disconnected parts of the line graphs indicate that no data was recorded during that periods. Third, the amplitude of seismic event is expressed as relative amplitude in log scale, by setting the amplitude of the first event as 1.0.

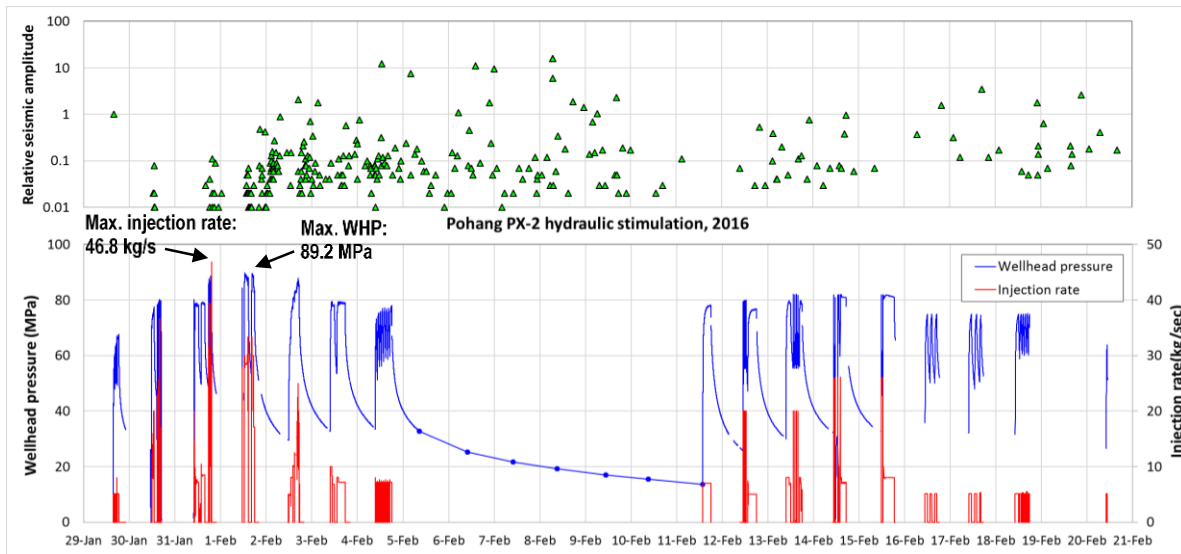


Figure 3 Stimulation data of Pohang PX-2 well observed from Jan 29, 2016 to Feb 20, 2016

3. ANALYSES ON THE OBSERVED RESULTS

Various approaches were attempted to evaluate and track the change of physical properties of the reservoir through the analyses on the stimulation data. Evaluations of equivalent aperture and injectivity were conducted to quantitatively evaluate the change of reservoir hydraulic performance during the stimulation period. Comparisons were made between the Pohang PX-2 stimulation case and other EGS stimulation cases. Required injection pressures for hydraulic shearing and hydraulic fracturing were estimated and compared with the observations.

3.1 Equivalent aperture

When fluid is injected into the reservoir with constant flow rate and the fluid pressure varies within that injection period, the reservoir permeability and corresponding equivalent aperture can be evaluated. In a single well, the change of hydraulic head in time can be expressed (Domenico and Schwartz, 1998) with constant injection or production rate as:

$$s_1 - s_2 = \frac{Q}{4\pi T} \ln \frac{t_1}{t_2} \quad (1)$$

Using Eq. (1), transmissivity of the reservoir can be calculated from the pressure-time curve sections of stimulation data if injection rate is constant and pressure is changing with time. By converting the pressure-time curve to hydraulic head-log time curve, the slope $Q/4\pi T$ can be obtained, thus the reservoir transmissivity T can be evaluated.

Once the reservoir transmissivity is obtained, the hydraulic conductivity and permeability of the reservoir can also be evaluated from the reservoir transmissivity. If a single major fracture exists as the only flow path in the reservoir, its equivalent aperture can be calculated (Eq. (2)).

$$K = T/D, \quad k = \mu K / (\rho g), \quad e = (12kD)^{\frac{1}{3}} \quad (2)$$

Injection sections with increasing pressure under constant flow rate were selected throughout the whole stimulation period, and then reservoir permeability and corresponding equivalent aperture were calculated from those sections. Fig. 4 is the resulting equivalent aperture versus initial wellhead pressure curve that correlating the calculated equivalent apertures with the wellhead pressures in the middle of pressure increasing sections in which each aperture was evaluated. The evaluated equivalent aperture varies from 58 μm to 550 μm , which corresponds to the reservoir permeability changing within 0.1 mD to 93.6 mD range. Nonlinear trend of aperture-pressure relation is well observed from Fig. 4.

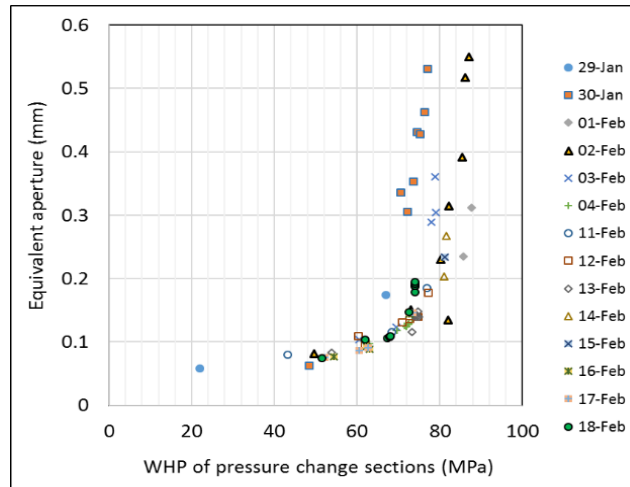


Figure 4 equivalent aperture-initial WHP curve obtained from the stimulation data

3.2 Injectivity index

Under the assumption of radial flow near wellbore, productivity and injectivity indices are defined (Economides and Nolte, 2000) as Eq. (3):

$$\frac{Q}{p_{wf} - p_e} = \begin{cases} \text{Productivity index} & \text{if } p_e > p_{wf} \\ \text{Injectivity index} & \text{if } p_e < p_{wf} \end{cases} \quad (3)$$

Injectivity index implies the achievable flow rate under certain pressure gradient between reservoir and bottomhole. In this regard, injectivity index is widely used to evaluate the effectiveness of reservoir performance enhancement before and after a hydraulic stimulation. The main difference of injectivity index calculation and equivalent aperture calculation is that, injectivity index is calculated from the section where both injection rate and pressure are constant, while the equivalent aperture is calculated from the section where injection rate is constant and pressure is increasing.

The target section of injectivity index calculation is mainly extracted from the step rate increase and decrease treatment sections. Many different injection rates are used and constant pressure values are given for each injection rate. Injectivity index is then obtained as the slopes of injection rate-pressure curve. Additionally, injectivity evaluation can be conducted by adopting the wellhead injectivity, which is simply calculated as constant injection rate divided by steady wellhead pressure. The injection rate-pressure curve obtained from step rate tests typically shows nonlinear trend; the slope increases, i.e., the injectivity increases as the pressure increases.

Constant rate-constant pressure sections were selected from the whole stimulation period and each pressure and injection rate sets were plotted as points on the pressure-injection rate curve (Fig. 5). As shown in Fig. 5 (a), the wellhead injectivity varied within the range of 0.065 ~ 0.532 L/s/MPa. Injectivity index from the slope of injection rate-wellhead pressure curve was evaluated and shown in Fig. 5 (b). It is noticeable that injectivity index suddenly increased during the stimulation in January 30th at the wellhead pressure of 73 MPa; the average injectivity index increased 2.7 times, from 1.04 L/s/MPa before January 30th to 2.81 L/s/MPa after January 30th. Such a transition to higher injectivity index seemed to have a permanent effect on the reservoir, because the increased injectivity index had maintained after Jan 30th. It may imply that a certain level of permeability enhancement was achieved by the stimulation.

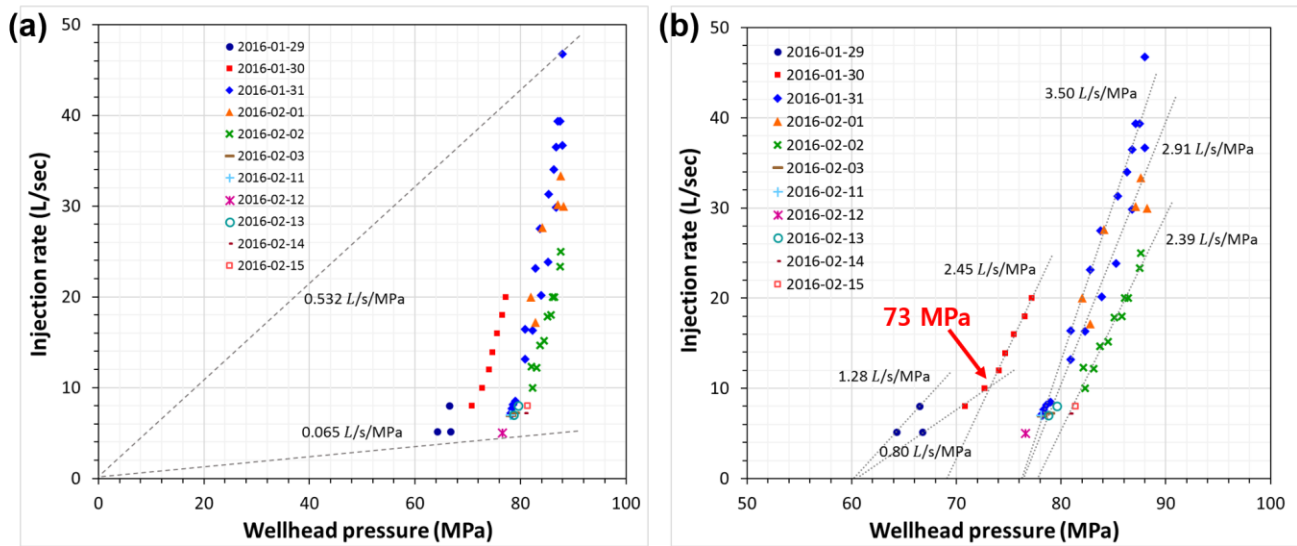


Figure 5 injection rate vs. pressure curves for injectivity evaluation – (a) wellhead injectivity; (b) injectivity index from the slopes

When interpreting the consistence of injectivity indices among slopes (3) ~ (6) in Fig. 5, it should be noticed that the curves moved to the high pressure region while maintaining the injectivity index. It can be understood as a consequence of the reservoir pressure build-up due to the continued injection. In other words, although the injectivity index had been maintained, the required bottomhole pressure had been increased to fulfil the required pressure gradient between the reservoir and bottomhole when the reservoir pressure had been increased due to the continued fluid injection.

3.3 Comparisons with other EGS stimulation cases

Previous study by Xie et al. (2015) compared the seven EGS stimulation sites including Soultz (France), Basel (Switzerland), Fenton Hill (US), Rosemanowes (UK), Cooper Basin (Australia), Hijiori and Ogachi (Japan). Pohang PX-2 stimulation case is added to the comparison, as shown in Fig. 6. In Fig. 6 (a), the correlation between the maximum seismicity magnitude and the normalized differential stress was investigated. It is noticeable that the maximum seismicity magnitude increases linearly with the normalized differential stress except Ogachi case, and Pohang PX-2 case is also following the trend. The maximum seismicity magnitude occurred during PX-2 stimulation was about M1.4, which was quite acceptable compared to the cases of Soultz, Basel and Cooper Basin. Fig. 6 (b) is showing the increasing trend of the number of seismic events along with the increasing injection volume in log-log plot. Pohang PX-2 case is also following the trend of this correlation, but the total injection volume and also the number of seismic events were far less than other sites.

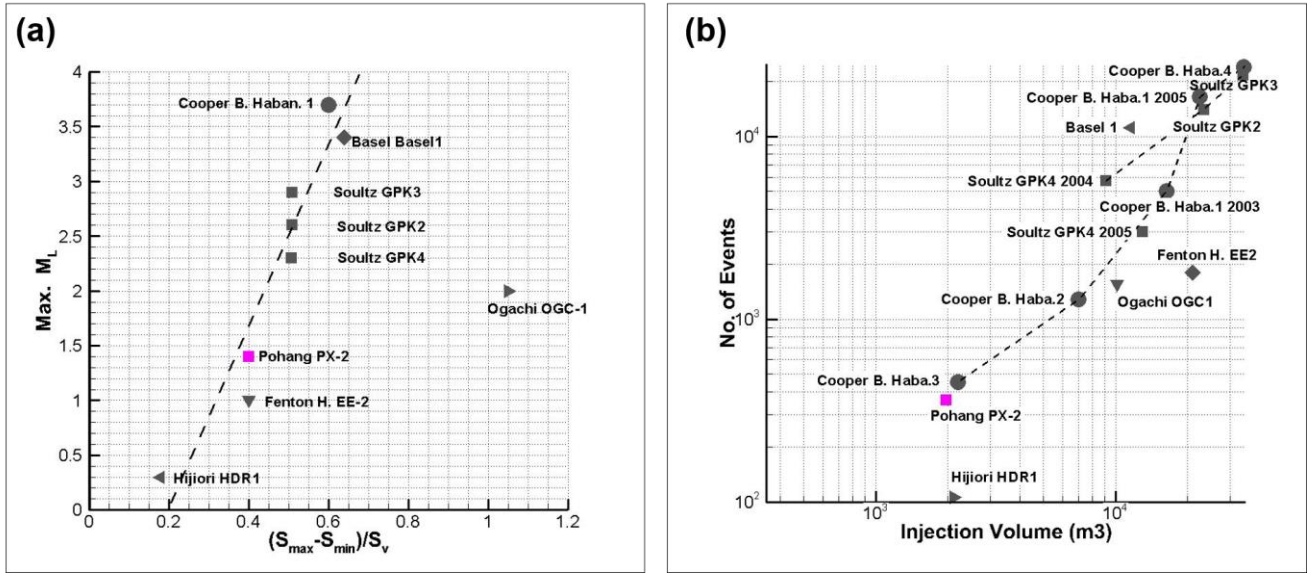


Figure 6 comparisons of Pohang PX-2 stimulation with other EGS stimulation cases – (a) maximum seismicity magnitude versus normalized differential stress; (b) Number of events versus total injection volume (modified from Xie et al. (2015))

3.4 Required pressures for hydrofracturing and hydroshearing

Fracture propagation and reservoir permeability enhancement in hydraulic stimulation are mainly driven by two mechanisms: hydrofracturing and hydroshearing. Hydrofracturing means the generation of new fractures by inducing tensile failure, and hydroshearing can be explained as inducing a shear slip of an existing joint or fault in a reservoir. For both hydrofracturing and hydroshearing, the required fluid pressure for each mechanism can be analytically estimated under given conditions on the in-situ stress magnitudes and orientations.

For hydroshearing, an analytic hydroshearing model developed (Xie and Min, 2016) by extending the slip tendency concept was applied for the estimation. The critical pressure is calculated as Eq. (4), using Eq. (5):

$$P_c = \sigma - \tau / \tan \phi \quad (4)$$

$$\sigma = \sigma_1 l^2 + \sigma_2 m^2 + \sigma_3 n^2, \quad \tau = [(\sigma_1 - \sigma_2)^2 l^2 m^2 + (\sigma_2 - \sigma_3)^2 m^2 n^2 + (\sigma_3 - \sigma_1)^2 n^2 l^2]^{1/2} \quad (5)$$

For hydrofracturing, the critical pressure is called as breakdown pressure and can be calculated as Eq. (6):

$$P_b = 3S_{h\min} - S_{H\max} + S_t \quad (6)$$

As one can notice from the equations, only the in-situ stress magnitudes are required for estimating the critical pressure for hydrofracturing. The in-situ stress conditions and the joint orientations are required for the hydroshearing critical pressure estimation. In this regard, the assumptions and scenarios were made for critical hydroshearing pressure estimation.

The orientation of the major fracture zone at the site was assumed as 67° dip and 25° dip direction based on the lineament observed on the geological plane and the previous Magnetotelluric exploration result for Pohang site area. For in-situ stress magnitudes, three scenarios were made considering the hydrofracturing test, borehole breakout and drilling-induced tensile fracture observations in 670 m ~ 810 m depth of Pohang EXP-1 well (Table 1). The stress ratio, defined as maximum horizontal stress divided by minimum horizontal stress, was originally determined as 1.7 from the observations of EXP-1, but the stress ratios of 1.4 and 1.1 were also considered for the uncertainty at 4.3 km deep target section of the stimulation. For the in-situ stress orientations, three scenarios were made for maximum horizontal stress azimuth: 130°, 100°, and 65°. Azimuth 130° scenario is close to the EXP-1 observation result and on the other hand, azimuth 65° scenario is based on the PX-2 well logging conducted by the drilling contractor (Union Petro, China). The last scenario with azimuth 90° was chosen as a case in between. The joint friction angle of 26.6° was used for the estimation, based on the direct shear test of rock joints cored from 4.2 km of PX-2 well. The estimated critical pressures for hydroshearing are shown in Table 2, varying within the range of 9.8 MPa to 58.9 MPa as wellhead pressure.

Table 1 Scenarios on the in-situ stress magnitudes

Target depth (m)	Vertical stress (MPa)	$S_{H_{max}}$ (MPa)	$S_{h_{min}}$ (MPa)	Stress ratio ($S_{H_{max}}/S_{h_{min}}$)	Stress regime
4,278	110.25	138.8	81.7	1.7	Strike-slip faulting
		128.6	91.9	1.4	
		115.5	105.0	1.1	

Table 2 Hydroshearing critical pressure estimation

$S_{H_{max}}$ azimuth	Stress ratio ($S_{H_{max}}/S_{h_{min}}$)	Estimated critical wellhead pressure for hydroshearing (MPa)
130°	1.7	15
	1.4	33.8
	1.1	58
90°	1.7	9.8
	1.4	30.5
	1.1	57
65°	1.7	20
	1.4	37.1
	1.1	58.9

The required breakdown pressures for hydrofracturing were estimated as 72.9 MPa at stress ratio of 1.7, 113.7 MPa at stress ratio of 1.4, and 166.1 MPa at stress ratio of 1.1 as wellhead pressure, considering the tensile strength of 9.17 MPa measured from the rock cores sampled at 4.2 km depth of PX-2 well.

Recalling that the pressure drop in January 29th occurred at 67 MPa and the injectivity index enhancement in January 30th occurred at 73 MPa, the estimation of based on hydroshearing mechanism is considered as an improper explanation, considering the estimated pressure range of 9.8 ~ 58.9 MPa. Instead, the estimation based on the hydrofracturing mechanism is considered as the best explanation that well matches the observations with the estimated breakdown pressure of 72.9 MPa.

4. CONCLUSIONS

The first large scale hydraulic stimulation in Korea had been conducted in the PX-2 well 4.3 km depth at Pohang EGS development site from Jan 29th, 2016 to Feb 20th, 2016. 89.2 MPa of maximum wellhead pressure and 46.8 kg/sec of maximum injection rate were recorded during the stimulation. In terms of the seismicity occurrence, an interesting trend was observed that the microseismic events occurred more frequently with larger amplitudes in the shut-in phases than in the injection phases.

Two different approaches were attempted to evaluate the hydraulic performance enhancement by the stimulation. Through the equivalent aperture analysis, the equivalent aperture of the reservoir was figured out as 58 ~ 550 μm corresponding to 0.11 ~ 93.61 mD of reservoir permeability. Through the evaluation of the injectivity index, injectivity index was found to be increased by 2.7 times during the stimulation in Jan 30th at the wellhead pressure of 73 MPa.

Based on the scenarios on in-situ stress magnitudes and orientations and the assumptions on the major fracture zone orientation, critical fluid pressures for hydroshearing and hydrofracturing were estimated as 9.8 ~ 58.9 MPa and 72.9 ~ 166.1 MPa in wellhead pressure, respectively. In current stage, the hydrofracturing or the hydraulic jacking are considered as the best mechanism that explains the observations in PX-2 stimulation, but further investigations would be required to obtain more information in various aspects.

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NOMENCLATURE

Q	volumetric flow rate
T	transmissivity
t	time
s	hydraulic head
K	hydraulic conductivity
k	permeability
D	reservoir thickness
g	gravitational acceleration
ρ	density of the injected fluid
μ	viscosity of the injected fluid
e	equivalent aperture
P_e	reservoir pressure at the no-flow boundary
P_{wf}	bottomhole flowing pressure
P_c	critical fluid pressure for shearing a specific fracture
σ	resolved normal stress on a fracture
τ	resolved shear stress on a fracture
ϕ	friction angle of a fracture
l, m, n	direction cosines
P_b	breakdown pressure
S_{hmin}	minimum horizontal stress
S_{Hmax}	maximum horizontal stress
S_t	tensile strength