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Analysis of Well-Tests in Balcova-Narlidere Geothermal Field, Turkey

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ABSTRACT

In this work, analyses of two injection/falloff and two pressure drawdown tests in the Balcova-Narlidere geothermal field, Turkey, are presented. The pressure data are analyzed by using modern well-test analysis techniques, such as pressure derivative to identify flow regimes exhibited by the data and regression analysis to estimate formation parameters. The pressure tests conducted, in general, show that the tested wells produce from a "reservoir" with a complex network of system consisting of communicating and noncommunicating fractures/faults. For example, the pressure-derivative behavior of the wells BD-2, BD-5 and BD-7 resembles the behavior of a well located near a high-conductivity communicating fault zone, while the pressure-derivative behavior of the BD-6 well indicates that the well is located near a sealing (non-communicating) fault zone. The estimated values of flow capacities (*kh*) from the analyses of well-test pressure data for these four wells changed from 3 to 121 darcy-m.

1. INTRODUCTION

Located in the south of Izmir bay and 10 km to the west of Izmir city, the Balcova-Narlıdere geothermal field is known as the oldest geothermal field of Turkey (Figure 1). Thermal springs existed prior to its exploitation and were known as the "hot springs of Agamemnon." Exploration studies in the field were started in 1962.

The geothermal system can be classified as a low temperature, single-phase liquid-dominated system containing water (salinity of 1500 ppm and CO_2 content less than 0.1% by weight), with temperatures between 80 ^oC and 140 ^oC, ranging in depth from 48.5 m to 1100 m (Satman et al., 2001). It is believed that the system is quite complex and is a fractured/faulted zone, in which hot water ascends over an area of about 2 km along a major fracture zone associated with the Agamemnon Fault (denoted by the symbol AI in Figure 2). Figure 2 is a structural map of Balcova-Narlidere geothermal system, including all well locations, and is based on alluvium thickness and alluvium-flysch contacts observed in wells (Ongur, 2001). The intense tectonic activity in the field has created a series of east-west and south-north oriented faults (and related fractures), as shown in Figure 2. The dips of the faults range from 60^o to 80^o (Yılmazer, 1989). The most important fault in the area is the east-west oriented Izmir Fault, which is locally called as the Agamemnon Fault (AI in Figure 2) and extends over 30 km (Yılmazer, 1989 and Ongur, 2001).

The hot water discharges via two concealed horizontal flows, one in the alluvium (upper 100 m) and another deeper zone in more permeable, ill-defined layers in the flysch formation (also referred to as the Izmir Flysch) between 400 and 700 m depth. Figure 3 shows a generalized stratigraphic sequence of the studied region. As shown in Figure 3, the Izmir Flysch is composed of a sequence of different facies, such as metasandstones, clayey schist, limestones and serpentinite and diabase (Serpen, 2004). The faults and joint sets seen in the Izmir Flysch sequence are probably the main causes of the secondary permeability. The thickness of this sequence is estimated to be over 2000 m (Ongur, 2001).

The geothermal energy from the field has been utilized for district heating since 1996. The district heating system has lately reached a heating capacity equivalent to 8200 households. Although the field was explored in 1960s, not much quantitative information on reservoir characteristics (permeability, fault/fracture networks, etc.), which is essential for understanding and modeling the production performance of the field, was available. To acquire such information, pressure transient tests were conducted in the field during the 2000-2001 season within a production/reservoir performance project, funded by the management of the field. As a part of this project, four existing "deep" wells; BD-2, BD-5, BD-6 and BD-7 (see Figure 2 for the locations of wells) have been the subject of various well tests.

The objective of this work has been estimation of permeabilities and evaluation of the existing network of faults/fractures in and around the wells from well test pressure data obtained from the BD-2, BD-5, BD-6, and BD-7 wells. The analyses of these pressure transient tests have provided estimates of injectivity/productivity and formation permeabilities, as well as invaluable information towards the characterization of the reservoir/production characteristics of the Balcova-Narlidere field.

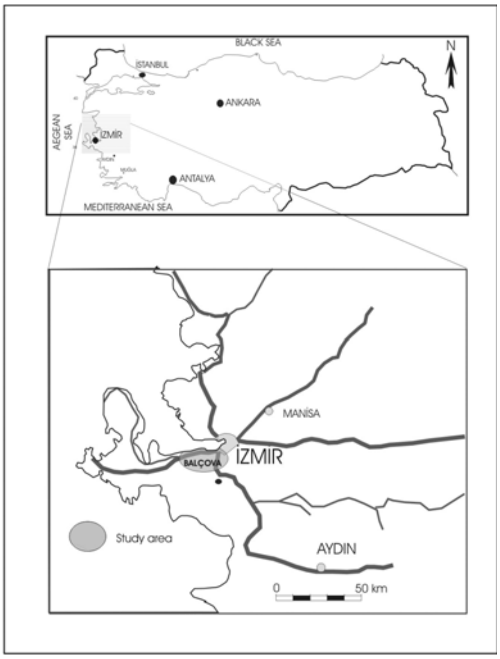

Figure 1: Location of Balcova-Narlidere geothermal field (modified from Aksoy and Filiz, 2001).

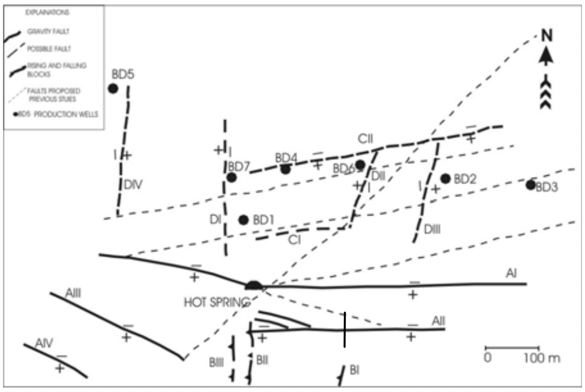

Figure 2: Structural map and well locations of Balcova-Narlidere field at seal level (Ongur, 2001).

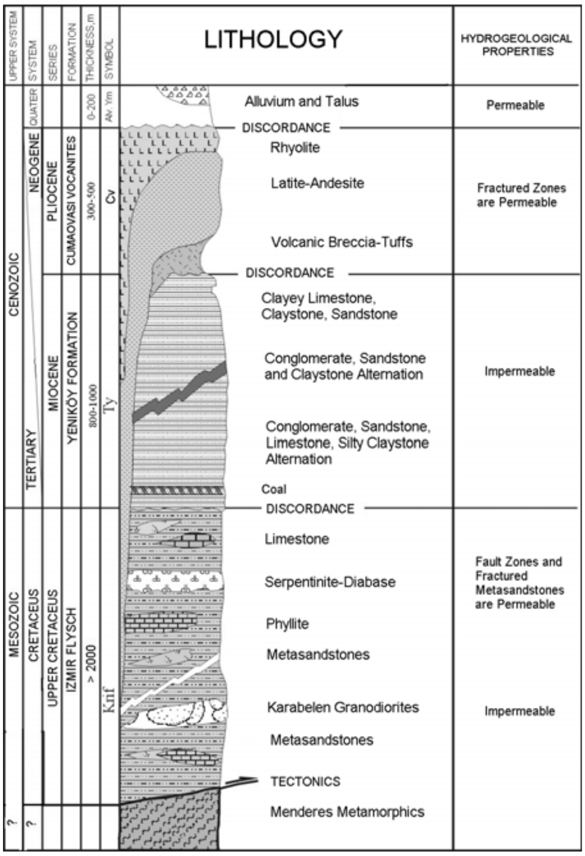

Figure 3: Generalized stratigraphic sequence of the studied region (modified from Aksoy, 2001a).

2. INJECTION/FALLOFF TESTS AT WELLS BD-2 AND BD-5

Here, we analyze injection/falloff tests conducted at wells BD-2 and BD-5 in the summer of 2000 during no heating season. Both well-test pressure data were measured with the Amerada tool equipped with mechanical gauges (bourdon tube).

2.1 Well BD-2

Prior to injection/falloff test at the BD-2 well, the well BD-2 had been used as a reinjection well. The BD-2 well has a depth of 677.2 m, and it was completed with casing of diameter 9 5/8 inches up to the depth of 348 m. From the depth of 348 m to 677.2 m, the well is open hole with a diameter of 8 1/2 inches (Yılmazer and Yakabagi, 1995). Static measurements of pressure and temperature versus depth were taken up to a depth of 414 m prior to the injection/falloff test because the Amerada tool cannot be lowered to a deeper depth due to possible sediment accumulation in the bottom of well. The initial static temperature and pressure measured at this depth were 87 ^{o}C and 512.3 psig (35.3 barg), respectively. A complete record of pressure vs. time is shown in Figure 4. The data for the first 60-minute period shown in Figure 4 corresponds to lowering the Amerada to a depth of 414. The injection was started at 60 min, and continued for 725 minutes. The duration of the falloff was 655 minutes. The flow rate data during injection were obtained by numerically differentiating the cumulative injection rate data, measured at every 5 minutes during the injection period. The temperature of the injected fluid was about 65 ^{o}C. Figure 5 shows the injection and cumulative injection rate vs. time data. As can be seen from Figure 5, the total amount of water injected during the injection period is about 770 m^3, and the injection rate is roughly constant at a value of 65 m^3/h prior to falloff. The injectivity index for the BD-2 well was computed as 2.2 (m^3/h)/psi, which indicates "high" injectivity at the BD-2 well.

To identify the flow regimes exhibited by the data, pressure-derivative data for the falloff period were investigated (Figure 6). Here, and throughout, the pressure-derivative refers to the derivative of pressure (or pressure change) with respect to the natural logarithm of falloff time (Bourdet et al., 1983), and is calculated by using the method of smoothing splines (Onur and Saddique, 1999). Because the quality of pressure-derivative data beyond 100 minutes is not very good, only the derivative data for the first 100-minute period of the falloff are shown in Figure 6. The derivative data in the time period from 3 min. to 18 min. indicate wellbore storage and skin effects, though we do not observe a unit slope line on both pressure change and derivative at early times. Nearly a constant derivative (or zero slope line) value in the time interval from about 18 min. to 28 min. is indicative of radial flow period. From this radial flow period, we computed flow capacity *kh* as 37 darcy-m (using an injection rate of 65 m^3/h and water viscosity of 0.324 cp at 87 ^{o}C) and skin factor, S = -2. The decline of pressure-derivative data more than one order of magnitude after 28 min (Figure 6) can be due to a high-conductivity communicating fault near the well (Abbaszadeh and Cinco-Ley, 1995; Kuchuk and Habashy, 1997) or radial composite reservoir for which the outer zone mobility is much larger than the inner zone mobility. The geological data based on our knowledge suggest a constant pressure boundary model, which is likely to be due to a high-conductivity communicating fault near the well. Based on the work of Abbaszadeh and Cinco-Ley (1995) and Kuchuk and Habashy (1997), the deviation from radial flow occurs at a dimensionless time value $t_{Df} \approx 0.25$, where this dimensionless time defined as,

$$t_{Df} = 2.637 \times 10^{-4} \frac{(kh/\mu)}{(\phi c_t h) d_f^2} t \qquad (1)$$

when the pressure transients reach the fault plane. In Eq. 1, d_f is the distance to the fault in ft and t is in h. All parameters in Eq. 1 are in oil-field units.

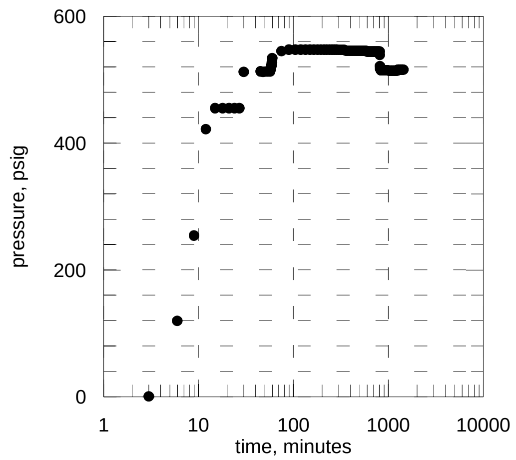

Figure 4: Pressure vs. time data for the injection/falloff test at the BD-2 well.

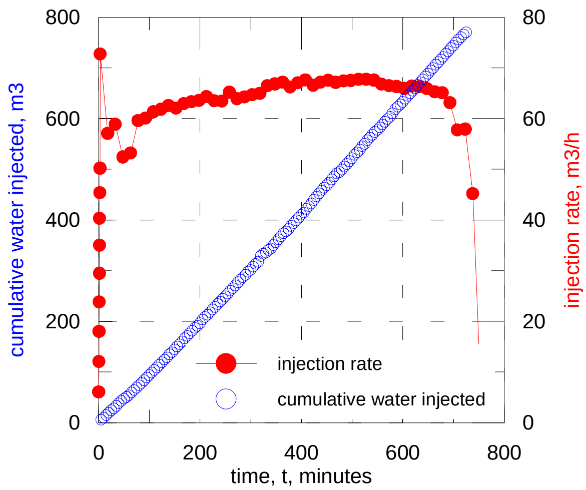

Figure 5: Cumulative water injected and injection rate vs. time data for the injection/falloff test at well BD-2.

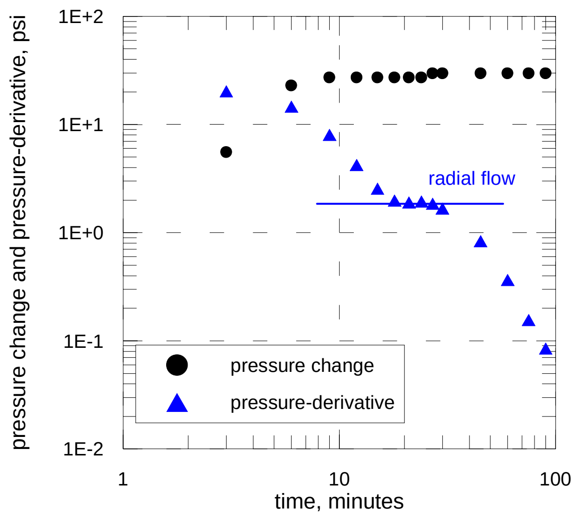

Figure 6: Pressure and derivative data for the falloff period at the BD-2 well.

As can be seen from Figure 6, pressure-derivative deviates from radial flow at a time about 28 minutes. Using this time value in Eq. 1 and considering the fact that the dimensionless deviation time is about 0.25, when the pressure transient reaches the fault plane, we computed the distance to the fault as d_f = 174–307 m. As we have uncertainty in the thickness of the feed zone as well as in the porosity (ϕ) and total compressibility (c_t), we gave a range for the estimate of the distance to the fault, d_f. The porosity of the system is believed to change between 2-5% (Satman et al., 2001), while the total compressibility of the system to change between 1.82x10^{-5} to 2.12x10^{-5} 1/psi (assuming consolidated sandstone and pure water at 80^{o}C, see Horne, 1995 for correlations for rock compressibility and water compressibilities), and thickness of the feed zone to change between 64 m to 200 m. Based on structural map shown in Figure 2, the estimated values of the distance to the fault (d_f = 174-307 m) seem to indicate Agamemnon fault (AI in Figure 2) or the fault denoted by CII in Figure 2. Because the dips of these faults are around 75^{o}, we find that the distance between the BD-2 well and Agamemnon fault is 200 m at 400 m below SL, whereas the distance between the BD-2 well and the fault CII is 296 m at 400 m below SL. These values fall in the range of d_f estimated from Figure 6.

Next, using a simple homogeneous model, we performed nonlinear regression analysis based on matching both the injection and falloff pressure data by accounting the entire flow rate history to estimate flow capacity *kh*, the skin factor (S) and the wellbore storage coefficient (C). The estimated values for these parameters (and their associated 95% absolute confidence intervals given as ±) are as follows: *kh* = 47±16 darcy-m, S = 0.5±3.5, C =4.x10^{-4}±1.2x10^{-4} bbl/psi. The *kh* and skin (S) values are in agreement with those estimated from the analysis of falloff period data alone. The root mean square (rms) error for the history match of entire measured pressure data was 3.9 psi, which is reasonable for the Amerada gauges. Shown in Figure 7 is the history match of measured pressure data with model pressure data.

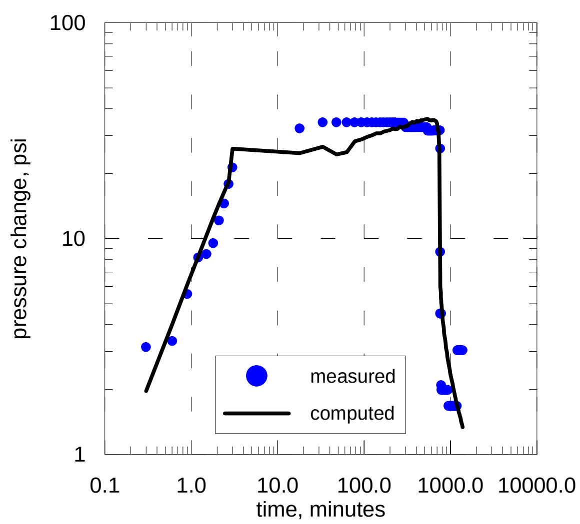

Figure 7: History match of pressure vs. time data for the injection/falloff period at the BD-2 well.

2.2 Well BD-5

The BD-5 well is the deepest well in the field. It has a depth of 1100 m, and it was completed with casing of diameter 9

5/8 inches down to the depth of 595.5 m. From the depth of 610 m to 1100 m, the well is open hole with a diameter of 8 1/2 inches. A slotted pipe with a diameter of 7 inches was set from 584.54 m to the bottom of the well to prevent sediment accumulation (Yilmazer et al., 1999).

Prior to the injection/falloff test, the Amerada tool was lowered to a depth of 590 m and the static measurements of pressure and temperature were taken. The static temperature and pressure measured at this depth were 105 °C and 760 psig (52.4 barg), respectively. A complete record of pressure and temperature data recorded during the injection/falloff test is shown in Figure 8. Injection was started about 50 min. after setting the tool at 590 m. Cumulative and instantaneous injection flow rate histories during the injection period are shown in Figure 9. The duration of injection was 24 hours, while the duration of falloff was 22.5 hours. Due to operational problems, the temperature of injected water could not be kept as constant during the entire injection period. For the first 150-minute period, the wellhead temperature of injected water was 65°C, afterwards it was 98°C, which is clearly reflected by the temperature data recorded at 590 m (Figure 8).

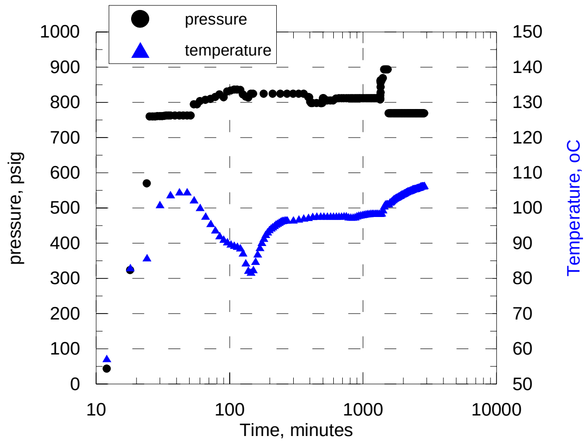

Figure 8: Pressure and temperature vs. time data at 590 m for the injection/falloff test at well BD-5.

The injectivity index for the BD-5 well was computed as 0.25 (m^3/h)/psi, which indicates low injectivity for the BD-5 well. As the quality of pressure data was not good, we did not looked at the derivative data for model identification. Using a simple homogeneous model (with $\phi c_t = 7.63\times10^{-7}$ 1/psi and μ = 0.288 cp @ T = 98 °C), we performed nonlinear regression analysis based on matching both the injection and falloff pressure data, by accounting the entire flow rate history, to estimate flow capacity *kh*, the skin factor (S) and the wellbore storage coefficient (C). The estimated values for these parameters (and their associated 95% absolute confidence intervals given as ±) are as follows: kh = 6.5 ±4.5 darcy-m, S = 1.3±6.7, C = 0.23±0.30 bbl/psi. The root mean square (rms) error for the history match of entire measured pressure data was 11.9 psi, which is high, but acceptable for the Amerada gauges. Shown in Figure 10 is the history match of measured pressure data with the model pressure data. As the temperature data were measured during the test at a depth of 590 m (Figure 8), one can estimate the “static” temperature at this depth from a Horner plot of temperature data during falloff. This analysis yielded a temperature of 110.8 °C (Onur et al., 2002).

Because it was observed that the injectivity of the well was decreasing after a year of injection in 2001, it was decided to conduct another injection/falloff test at the BD-5 well to evaluate the injectivity in November 2001. In this test, the Amerada tool (bourdon tube gauge) was set to a depth of 750 m to record pressure vs. time data. The injection rate prior to falloff period was 31.3 m^3/h, though there was no continuous record of injection rate with time during injection. The wellhead temperature of injected water at the onset of falloff was about 85°C, but it changed from 20 °C to 85°C during the injection period. During injection, wellhead pressure was changed from 220 to 260 psig. The duration of the injection period was 318 minutes. The duration of falloff is the same as that of injection period. The injectivity index for the BD-5 well was computed as 0.13 (m^3/h)/psi, which indicates that the injectivity of the well decreased by a factor of almost 2 over the one year period.

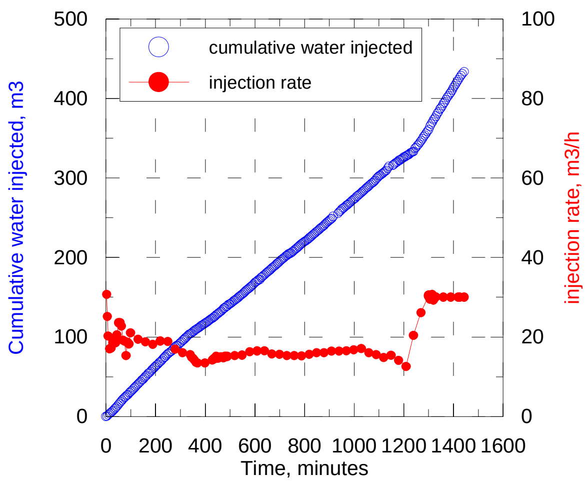

Figure 9: Cumulative water injected and injection rate vs. time data for the injection/falloff test at well BD-5.

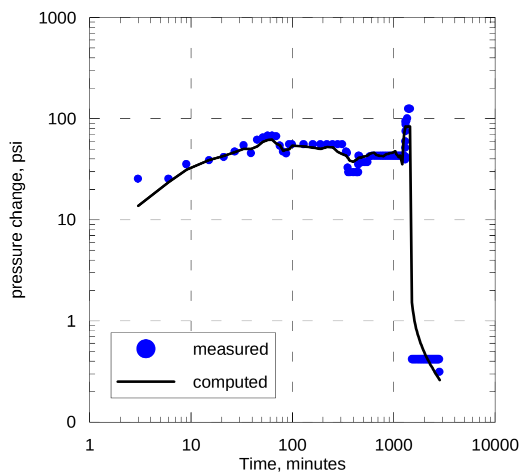

Figure 10: History match of pressure vs. time data for the injection/falloff period at the BD-5 well.

Because there was no continuous record of injection rate, we did not attempt to history match pressure data for both the injection and falloff period. Instead, we analyzed only the pressure data for the falloff period. The pressure change and derivative data for the falloff period are shown in

Figure. 11. The early-time derivative behavior from 0.5 min. to 4 min is typical of wellbore storage and skin effects, though derivative data do not exhibit a unit-slope line. In the time interval from 4 min. to 9 min, derivative data exhibit a radial flow period. After performing the standard semilog analysis of pressure data (not shown here) in this time interval, we computed kh = 4 darcy-m (using a viscosity value at μ = 0.331 cp @ T = 85 ^oC) and S = 8 (using ϕc_t = 7.63×10^{-7} 1/psi). Note that this kh value is in good agreement with the value of kh = 6.5 darcy-m obtained from the analysis of injection/falloff test at the same well in 2000. The high value of skin computed explains the poor injectivity of the BD-5 well, observed in 2001. The sharp decrease in derivative data from 9 min to 15 min. could be due to the outer fluid bank, which has high mobility (or low viscosity) due to fluid at a higher temperature surrounding the well. The original static temperature of this well was measured as 118 ^oC at a depth of 700 m (Yilmazer et al., 1999). The increase in derivative from 15 min. to 30 min and then decrease in derivative data which lie on a straight line with –1 slope in the time interval from 30 min to 150 min can be due to a high-conductivity communicating fault near the well. Based on the work of Abbaszadeh and Cinco-Ley (1995), one can estimate the distance to the fault from the slope of a Cartesian plot of $d\Delta p/\mathrm{dln}(t)$ vs. $1/t$. The slope of this straight line (assuming a negligible fault skin factor) is given by

$$d_f = 0.00193 \frac{kh}{\mu} \sqrt{\frac{m_s}{q\phi c_t h}} \qquad (2)$$

which is given in oil-field units. In Eq. 2, m_s represents the slope of straight line on a Cartesian plot of $d\Delta p/\mathrm{dln}(t)$ vs. $1/t$. Figure 12 shows a Cartesian plot of pressure-derivative vs. $1/t$ data for the falloff test at well BD-5. Using the slope value of m_s = 2.1 psi-h, and kh = 4 darcy-m determined from radial flow analysis, and considering a range for ϕc_t as 5.0x10^{-7}-1.1x10^{-6} 1/psi, a range for h = 35–100 m, and a range for μ = 0.33 – 0.24 cp, we estimated d_f = 35-134 m. As can be seen from the structural geological fault map given in Figure 2, there is a fault (denoted by DIV in Figure 2) near the BD-5 well. Assuming a dip angle of 75^o towards the west, the distance of the well to this fault is around 160 m.

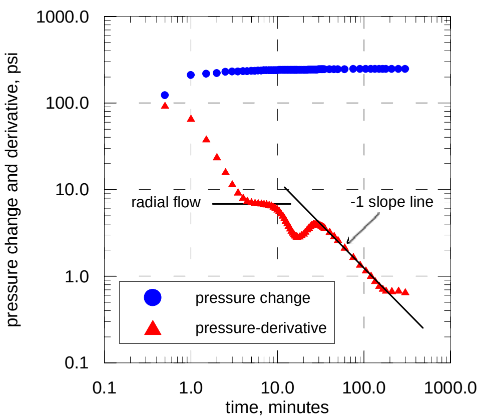

Figure 11: Pressure and derivative data for the falloff test in 2001 at the BD-5 well.

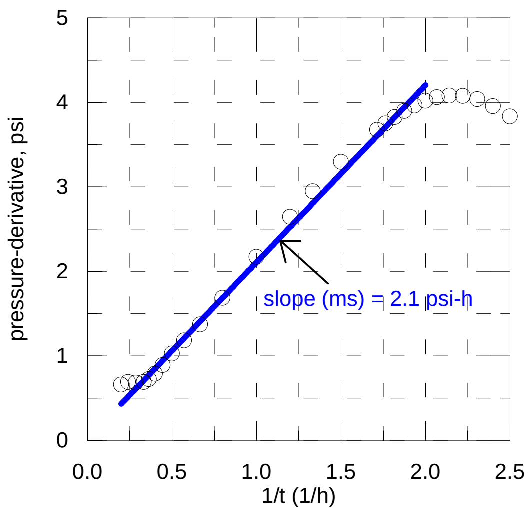

Figure 12: Pressure-derivative of field data vs. reciprocal of falloff time.

3. DRAWDOWN TESTS AT WELLS BD-6 AND BD-7

Here, we present the analyses of drawdown tests conducted at wells BD-6 and BD-7 in April and May 2001. Both wells were equipped with line-shaft pumps, which were set at a depth of 150 m. To measure pressures during the drawdown tests below the pumps, we used a capillary tube containing nitrogen (N_2) gas, lowered to a depth below the pump, as shown in Figure 13. The pressure (P2) recorded at the digital manometer represents the liquid pressure at the level of the bottom of the capillary tube.

3.1 Well BD-6

The BD-6 well has a depth of 606 m, and it was completed with casing of diameter 9 5/8 inches down to the depth of 295 m. From the depth of 298 m to 606 m, the well is open hole with a diameter of 8 1/2 inches. A slotted pipe with a diameter of 7 inches was set from 281 m to the bottom of the well to prevent sediment accumulation (Altay, 1999). Altay (1999) indicates that the producing interval is about 120 m. Recorded well head temperatures during production in 2001 changed between 135 ^oC and 138 ^oC.

The pressure measurements during the drawdown test were taken at a depth of 178 m from the wellhead using the capillary tube shown in Figure 13. The water production rate during the 2-hour drawdown test was kept constant at a value of about 49.5 m^3/h. The initial well head temperature was 135.3 ^oC, and the initial pressure prior to drawdown test was 223.65 psig. The viscosity of water at 135 ^oC is 0.21 cp.

Figure 14 presents the pressure change and pressure-derivative data for the drawdown test. The early-time derivative behavior in the first 150 seconds is quite interesting. The derivative data from 20 seconds to 65 seconds seem to fit well to a straight line with –1/2 slope, which is indicative of spherical flow regime. This may indicate that the well is producing from an open interval, which has a smaller thickness than the total thickness of the "reservoir." Unfortunately, we do not have information from well logs and water loss tests to verify this because the feeding zone(s) were not identified at this well, when it was drilled. In addition, we do not have accurate information about the total thickness of the producing formation at well BD-6. We cannot also explain the sharp decrease in derivative data in the time interval from 65 seconds to 150 seconds by the standard models used in well test analysis. The derivative data beyond 150 seconds exhibit two distinct radial flow regimes; one in the time interval from 150 s. to 310 s., and the other from 900 s to 4000 s. From the semilog plot of pressure vs. time data (Fig. 15), the slope ratio of these two radial flow regimes is around 2, the slope of the second radial being twice that of the first radial. The doubling of slope can be explained by several models; a non-communicating fault near the well, or radial composite model for which the inner zone mobility is twice that of the outer zone, or a transient double porosity model. As the latter two models, based on our knowledge of the geological data available, are not acceptable, we assume that this doubling of slope is due to a non-communicating fault near the well and perform analysis based on this model to estimate parameters.

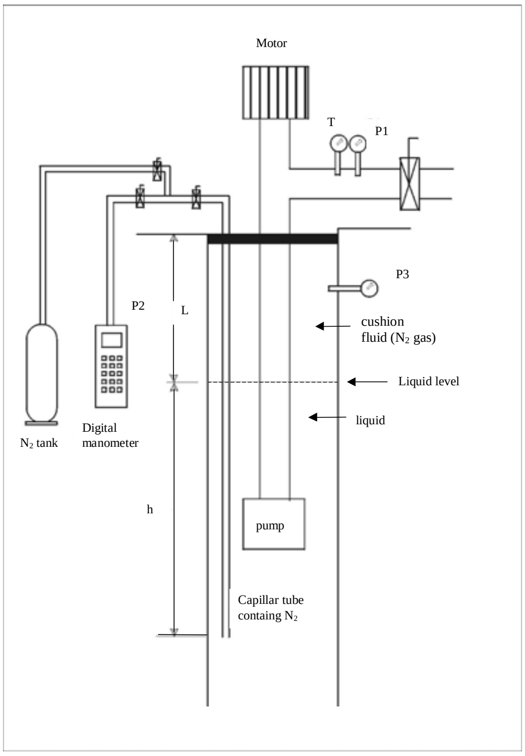

Figure 13: Schematic for the measurement of pressure-below the pump (modified from Aksoy, 2001b).

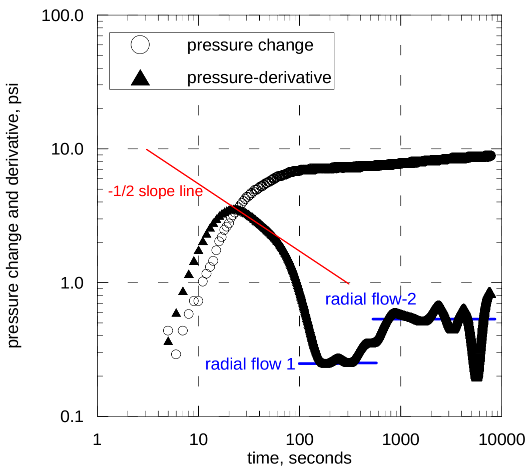

Figure 14: Pressure and pressure-derivative data for the drawdown test at the BD-6 well.

From the early-time semilog straight (radial flow-1) line shown in Figure 15, we computed kh = 116 darcy-m and the skin factor, S = 0.8. If one uses the slope of late-time semilog straight line (radial flow-2) to compute flow capacity, the flow capacity is computed as kh = 58 darcy-m. From the intersection time (t*) of the early- and late-time semilog straight lines (Figure 15), the distance to the fault was computed from the well-known formula (Earlougher, 1977)

$$d_f = 0.01217\sqrt{\frac{kht^*}{\phi c_t h\mu}} \tag{3}$$

as d_f = 100-154 m (using h = 120 m, and considering a range for ϕc_t from $5.0\text{x}10^{-7}$ to $1.06\text{x}10^{-6}$ 1/psi). Eq. 3 is in oil field units. As can be seen from the structural map shown in Figure 2, the BD-6 well is located between the two intersecting faults denoted by CII and DII. The distances between the BD-6 well and the faults CII and DII at a depth of 480 m below SL are 163 and 141 m, respectively. From a single well test, we cannot determine whether the fault exhibited by the pressure response of BD-6 well is the fault CII or the fault DII.

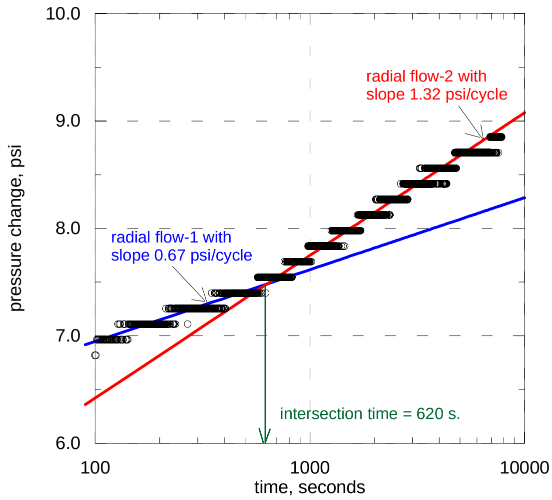

Figure 15: Semilog plot of pressure change vs. time data for the drawdown test at the BD-6 well.

3.2 Well BD-7

The BD-7 well has a depth of 700 m, and it was completed with casing of diameter 9 5/8 inches down to the depth of 332 m. From the depth of 334 m to 700 m, the well is open hole with a diameter of 8 1/2 inches. A slotted pipe with a diameter of 7 inches was set from 322.5 m to the bottom of the well to prevent sediment accumulation (Altay, 1999). Altay (1999) indicates that the producing interval is about 120 m. Recorded well head temperatures during production in 2001 changed between 118 ^{o}C and 120 ^{o}C. The original temperature of this well in 1999 was reported as 136.03 ^{o}C (Altay, 1999).

The pressure measurements during the drawdown test were taken at a depth of 178 m from the wellhead using the capillary tube shown in Figure 13. The water production rate during the 2.5-hour drawdown test was kept constant at a value of about 70 m^3/h. The initial well head temperature was 117.9 ^{o}C, and the initial pressure prior to drawdown test was 180 psig. The viscosity of water at T = 118 °C is 0.24 cp.

Figure 16 presents the pressure change and pressure-derivative data for the drawdown test. As can be seen from Figure 16, the early-time derivative data for the first 80 seconds indicate straight line with 1/2 slope, which is indicative of a high-conductivity vertical fracture intersecting the well. Figure 17 shows a Cartesian plot of pressure change vs. $\sqrt{t}$, which exhibits a well-defined straight line with slope of 3.63 psi/s$^{1/2}$. Also note that derivative data exhibit radial flow period in the time interval from 100 s. to 150 s, though its duration is not long. From this radial flow, we computed kh = 3.3 darcy-m. An estimate of the fracture half-length can be computed from the slope obtained in a Cartesian plot of plot of pressure change vs. $\sqrt{t}$ (Earlougher, 1977). Assuming h = 100 m and considering a range for ϕc_t from 5.0x10^{-7} to 1.06x10^{-6} 1/psi, we computed fracture half-length to be 15-22 m. Derivative data in the time interval from 150 s. to 500 s. exhibit a straight line with –1 slope, which may indicate a high conductivity communicating fault near the well. Performing a straight-line analysis on a Cartesian plot of derivative data vs. 1/t and using Eq. 2, we estimated the distance to the fault d_f = 21-50 m. This result seems to support the fault denoted by DI in Figure 2. These results may indicate that the BD-7 well is connected to a communicating fault via a fracture (or a network), and the well is very close to a communicating fault. Finally, we should note that derivative data exhibit another radial flow period in the time interval from 2000 s. to 9000 s. From this radial flow, we computed flow capacity kh = 121 darcy-m. This high kh value probably represents the flow capacity beyond the fault.

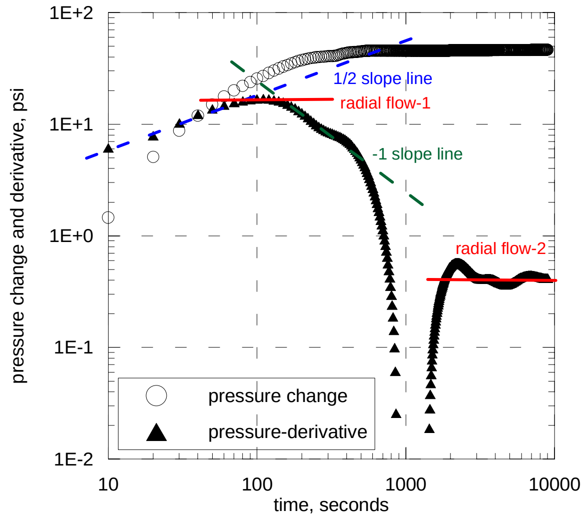

Figure 16: Pressure and pressure-derivative data for the drawdown test at the BD-7 well.

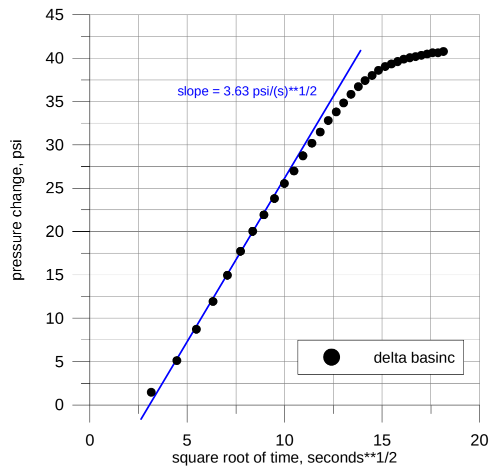

Figure 17: Square root of time plot for pressure data for the drawdown test at the BD-7 well.

4. CONCLUSIONS AND RECOMMENDATIONS

In this work, we analyzed four pressure transient tests conducted in the Balcova-Narlidere geothermal field, Turkey, to estimate permeability-thickness product and to identify the flow characteristics of the system. Based on our analyses of well-test pressure data obtained from four "deep" wells; BD-2, BD-5, BD-6 and BD-7, our specific conclusions can be summarized as:

(i) The flow capacity of the formation near the BD-2 well is in the range 31-62 darcy-m, and derivative data indicate that the well is located near a high-conductivity communicating fault.

(ii) The flow capacity of the formation near the BD-5 well is in the range 2-11 darcy-m, and derivative data indicate that the well is located near a high-conductivity communicating fault.

(iii) The flow capacity of the formation near the BD-6 well is in the range 58-116 darcy-m, and derivative data indicate that the well is located near a sealing fault.

(iv) The flow capacity of the formation near the BD-7 well is 3.3 darcy-m, and derivative data indicate that the well is intersected by a fracture (or a fracture network) connecting the well to a high-conductivity communicating fault zone having kh = 121 darcy-m.

After conducting these tests and analyzing them, we observed that major sources of uncertainty were the estimates for the thickness of the "reservoir" and feed zones intersecting the wells as well as porosity-compressibility product. Also, we observed that pressure gauges with high accuracy and resolution were needed because of the high permeability and strong recharge observed in the field. Therefore, we recommend that these observations be taken into an account before designing and conducting pressure transient tests in the Balcova-Narlidere geothermal system.

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