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Well Logging Analysis and Wellbore Simulation of Well SV-26 in Svartsengi Iceland

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ABSTRACT

Reservoir engineering datasets is important in order to have a successfull exploration program. Some of these datasets are obtained from well testing during drilling and recovery. This paper will focus on the analysis of such testing and will take an example of well SV-26 in Svartsengi, Iceland. Analysis of downhole pressure and temperature data in a 2500 m deep, results in a static water table at 425 m, a boiling point with depth zone to 700 m, and near isothermal 240°C single-phase water reservoir to total depth. Two major feedzones are identified at 1225 and 2200 m TVD (total vertical depth) and the well pressure pivot point is located at 1350 m TVD and at 77 bar-g. Multistage injection and production test analysis result in a cold well injectivity index of 11 kg/s/bar and a hot well productivity index of 28 kg/s/bar. Both indicate a very good reservoir. Detailed hydrological models of injection and production transient pressure data show well skin in the negative territory and reservoir permeabilities in the 10-1000 mD range. Higher model values arise from models calibrated against well data collected before running the 7” slotted liner. This may suggest that the lower cold water injectivity index relates to liner holes viscosity effects. A numerical flowing wellbore model was able to capture these properties; the bottomhole and wellhead pressure with flow and the dynamic temperature and pressure profiles with depth. The model predicts a shallow to deep feedzone ratio at 2:1. The modelled wellhead output curve infers a much higher maximum flowrate than the tested maximum of 47 kg/s, thereby taking well capacity close to 10 MWe.

1. INTRODUCTION

Logging analysis in a geothermal well is one of the means to obtain reservoir engineering datasets. In this paper, well SV-26 in Svartsengi in Rekjanes peninsula, SW of Iceland will be discussed. Svartsengi is a geothermal area that has been in development since the early 70s. The first well was drilled in 1971 continued with the first geothermal exploitation in 1976 (Björnsson and Steingrímsson, 1992). The power plant is currently producing 76 MWe of electricity and some additional 300 MW of heat (Georgsson, 2017).

The area is located in an active rift zone which is the extension of Mid-Atlantic ridge. It was situated in a basaltic rich surface with a sequence of lava flows and hyaloclastite underneath. The reservoir was initially in liquid-dominated phase with temperature between 230-240 °C and salinity corresponding to 2/3 that of seawater. With the continuous production, there is an expansion of two-phase zone due to pressure drawdown of the system ((Björnsson and Steingrímsson, 1992).

2. WELL LOGGING ANALYSIS

Well SV-26 was located in the southeast of the Svartsengi power plant. It was drilled in a directional inclination to reach 2537 m measured depth (MD). The drilling was finished in March 1st, 2016 (Weisenberger, 2016). All the well design parameters and measurement which are in m MD was processed with ICEBOX program to be converted in true vertical depth (TVD) unit as shown in Figure 1 (Arason et al., 2004).

The well is then continuously tested and logged through various kinds of tests to obtain the reservoir parameters during and after the well completion. The temperature loggings were conducted during and after the drilling, with one of the main reason is to predict the locations of the feedzones in the well. Aside from the temperature loggings, other loggings were also conducted such as pressure, XY-caliper, dual neutron, gamma resistivity and cement bond log (CBL) loggings.

Here, the focus is on the temperature and pressure loggings. These data are plotted against depth in TVD and compared to well design to better understand the properties of the well and the reservoir as shown in Figure 1 a and b. The temperature and pressure loggings in the well were conducted during different states of the well, such as during injection, warming up period, static condition and also during discharge condition. The measurement points are also tightly spaced with generally 0.5 m distance between measurement points to provide a more accurate interpretation in the logging analysis.

From the analysis of temperature and pressure logging, as shown in Figure 1 a and b, the temperature logging in injection and static well, prediction of the feed points of the reservoir in the well could be made.

Analysis of loggings while the well was injected on February 25th and 27th show that there is a feedzone at 1225 m TVD. Well logging on February 25th was conducted during injection of 20 kg/s that made the pressure in 1225 m TVD is higher than those in the reservoir. In that case, the feedzone acts as an outflow with partial loss which causes slight changes of the tempertaure as seen in the graph. While the later logging was conducted during injection of 15 kg/s of cold water which causes the well pressure in the 1225 m TVD feedzones is lower than the reservoir that’s why hot reservoir fluid flowing into the well that causes sudden changes in temperature. This logging also shows total lost circulation (TLC) zone at 2200 m TVD where all of the injected fluid is flowing out to the reservoir.

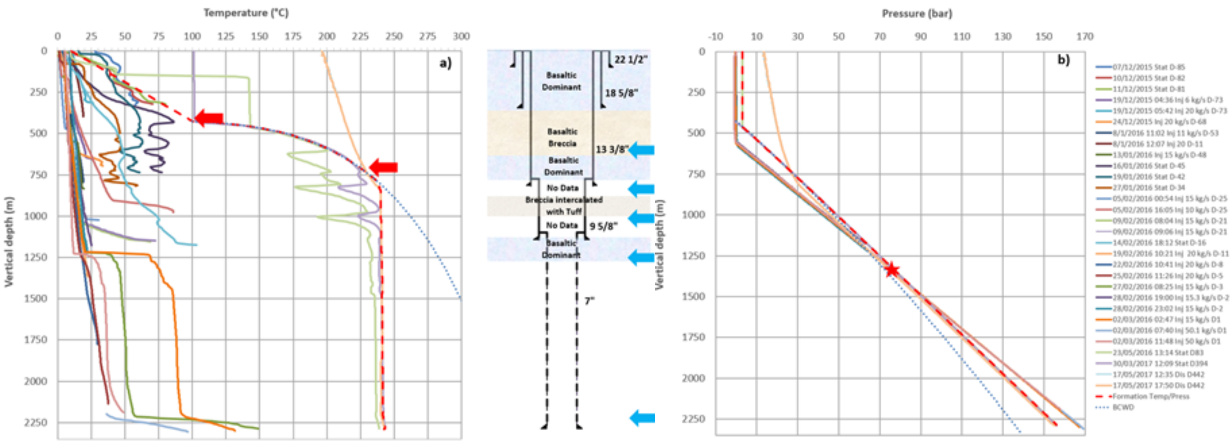

Figure 1: a) Temperature logging and b) pressure logging analysis and well design of well SV-26

The feed points also can be inferred from static well loggings as shown from loggings dated May 23rd, 2016 and March 30th, 2017. From the loggings, there are some feed points could be located in 625, 825 and 1000 m TVD that now behind the cemented casing. The lower temperature of those depths is because they are the feedzones that have been massively cooled by the injection and at that time contain cold water and drilling fluid.

From the graph, it is predicted that the fluid entering the well in a 240 °C liquid phase condition. Interzonal flow happens in the well between the depth of 1200 m TVD where the casing ends until the bottom of the well. It is categorized by isothermal line in the well that heat up more quickly than the other part. As the shallower part of well has lower pressure than the deeper part, the reservoir fluid in the well begins to boil between on 700 m TVD. It is indicated where the graph started to coincide with boiling point curve with depth (BCWD). This is also supported by the pressure logging result where all pressure loggings showing higher measured pressure than pressure in the BCWD.

From the pressure analysis, we can see the location of static water which is in 425 m TVD. Aside from that, we can also predict the pivot point of the well in 1350 TVD. Pivot point is a certain depth in the well where the pressure does not change along the injection or warm up survey. The pressure in the pivot point is the best indication of the real pressure of the reservoir which is 77 bar-g. When the result is crosschecked with the temperature loggings and the well design, the pivot point is located between two major feedzones 1225 and 2200 m TVD which usually happens in wells with more than one major feedzone (Grant et al., 1982).

According to Kutasov and Eppelbaum (2005), people usually determine the formation temperature based on to the bottom downhole temperature in the well, but this method does not necessarily provide the best estimation as drilling and injection alter the reservoir temperature in the well. One of the methods that are used to estimate the formation temperature is using Horner plot that has been widely used in petroleum engineering in the early 50s. The Horner method assumes that the well is cooled for the time (t_p), and the temperature is measured several times (Δt) after the circulation stopped. The formation temperature is estimated by plotting the data in a Horner plot and extrapolated to $\Delta t = \infty$, or $(tp + \Delta t)/\ \Delta t = 1$. The Horner plot is based on heat conduction equation.

$$(\rho C)\frac{\delta T}{\delta t} = K\nabla^2 T \quad (1)$$

That is why this method only governs the cooling and warming when conduction is the dominant mechanism in a well and therefore the method is less valuable when applied to zone of fluid loss or another permeable zone (Grant et al., 1982).

The formation temperature estimation in this paper uses BERGHITTI program that was developed by ISOR that works based on Horner method (Marteinsson, 2017). In Figure 1 a, one can see that the formation temperature is around 240 °C where the resulted value from BERGHITTI is almost the same as the temperature logging conducted in the well (March 30th and May 17th 2017). This is because when the loggings were conducted, the well already heats up for more than a year where it is already in equilibrium with the formation temperature of the reservoir.

3. INJECTION AND PRODUCTION TEST

Along with temperature and pressure logging interpretation, it is of interest to analyse the injection and production tests that were conducted in well SV-26. The purpose of conducting such test, is mainly to estimate the permeability of the well through injectivity or productivity indexes. Before conducting multistage injection or production tests, first of all, the location of the feedzones in the well should be estimated (Haraldsdottir, 2017). As injectivity, productivity or effective permeability value is bound to a certain feedzone only. That is why prediction of major feedzones as conducted in the previous chapter is of importance.

The value of reservoir flow in or out of the well does not necessarily imply a small or large value of permeability. The permeability could be estimated by the change of pressure in the intended measured feedzone when different injection rates are applied to the system. As mentioned before, placing of measuring devices in the exact location of the feedzone is important as placing the pressure gauge in the wrong level of the well may cause irregular or oscillatory result in the data analysis (Grant et al., 1982).

In well SV-26, two multistage injection test was conducted after the drilling was completed. The first multistage injection test was conducted on February 28th, 2016 and the second was conducted on March 2nd, 2016. A multistage production test was conducted more than a year later on May 17th, 2017.

3.1 First Multistage Injection Test

The first multistage injection test was conducted on February 28th, 2016 before the 7’’ slotted liner was installed in the well (Weisenberger et al., 2016). The pressure measurement was placed in 1225 m TVD in the shallower feedzone in the well as shown in Figure 1 (see chapter 2).

Initial injection rate of 15.3 kg/s corresponds to pressure of 64.4 bar, while the first stage injection rate of 50 kg/s corresponds to pressure of 66.3 bar and second stage injection rate of 15 kg/s correspond to of 63.7 bar. The three-stage multistage injection test is then plotted in a pressure versus injection rate graph as shown in Figure 2.

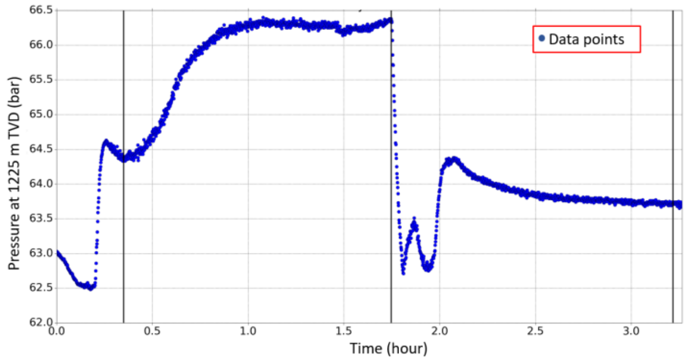

Figure 2: The first multistage injection test of well SV-26 before running the liner (February 28th 2016)

After the data were plotted, a linear trendline is made in the graph. Injectivity index is the ratio between the change of injection rate into the well which causes a certain change in well pressure or can be generated from the slope of the resulted trendline which is 14.3 kg/s/bar as shown in Figure 3.

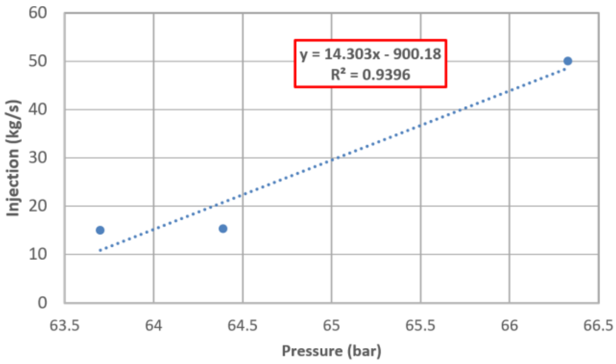

Figure 3: Injectivity index estimation of well SV-26 based on the first multistage injection test

The multi-stage injection test is then modelled with WELLTESTER program developed by ISOR to obtained reservoir properties such as transmissivity, storativity, skin factor and other parameters. For the model calibration, several initial model parameters are assumed and will be inverted by WELLTESTER. Other parameters that have to be assumed are porosity, dynamic viscosity, total compressibility of the reservoir, etc. The WELLTESTER program provides many kinds of condition for the modelling but in this paper, homogenous porosity of the reservoir, boundary condition which refers to a constant pressure, constant skin value for the well and also constant wellbore storage would be assumed as the reservoir condition for the modelling.

Figure 4 a and b show the result of the modelling which uses logarithmic scale for the pressure changes and the timescale together with derivative for the pressure response multiplied by time difference since the beginning of the steps. Modelling using derivative plot is commonly used to determine the best-fitted model for a certain measured data. Figure 4 a and 4 b show the modelling of the first step and the second step respectively. The reservoir properties obtained from the modelling will be discussed in the later part of this paper.

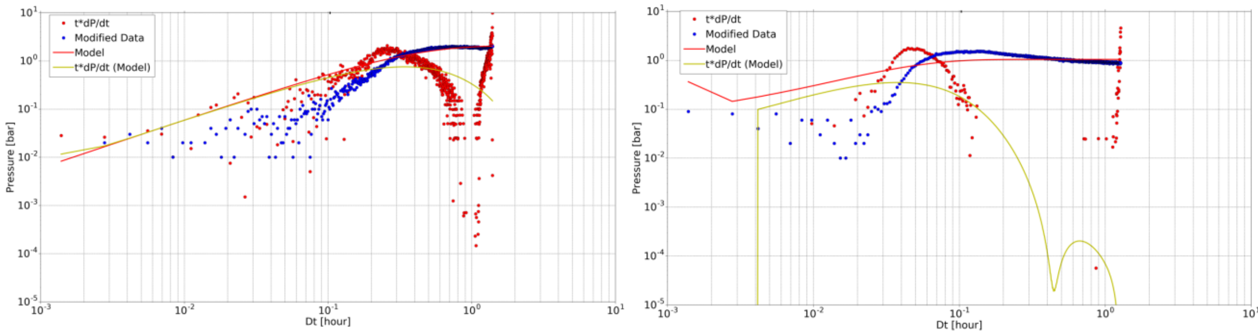

Figure 4: The modelling result of the first multistage injection test a) first step b) second step

3.2 Second Multistage Injection Test

The second multistage injection test was conducted on March 2nd, 2016 or 1 day after the drilling was completed. The pressure tool was placed in 2200 m TVD close to the bottom of the well where TLC happen (see Figure 1 in chapter 2). The well is initially injected with 15 kg/s water which corresponds to well pressure of 157.0 bar, then it was injected with flow rate 50 kg/s which corresponds to pressure 158.4 bar. The injection was decreased again to 15 kg/s which corresponds to well pressure of 155.1 bar and lastly, the injection was increased again from which corresponds to pressure of 158.3 bar. All the pressure measurement was plotted against time as shown in Figure 5.

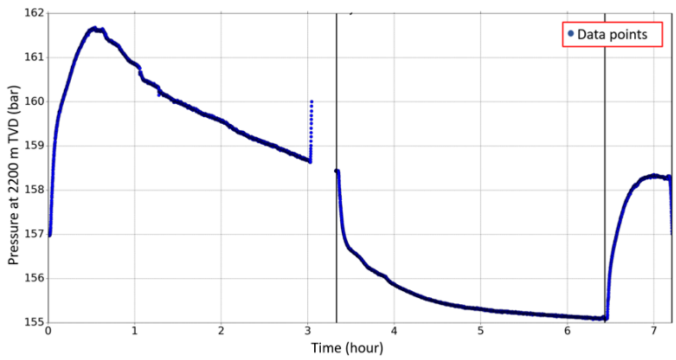

Figure 5: The second multistage injection test (March 2nd 2016)

The stabilized pressure of each steps are plotted against their correspond injection rate, as shown in Figure 6. A linear trendline is then made to generate a linear equation of y = 11.38x – 1756.4 which means that the injectivity index for the second multistage test is 11.4 kg/s/bar.

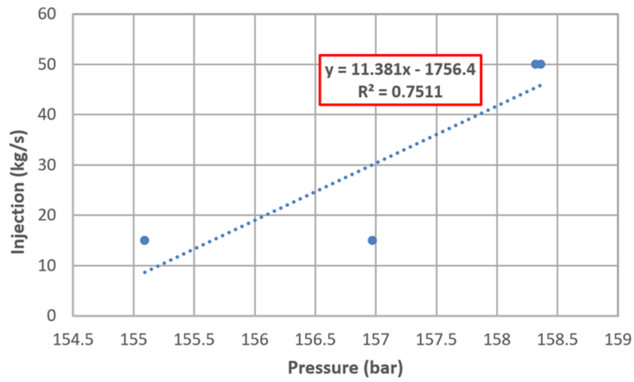

Figure 6: Injectivity index estimation of well SV-26 based on the second multistage injection test

The second multistage injection test is also modelled with the same properties as applied in the first multistage injection test in WELLTESTER program. The modelling result is shown in logarithmic pressure and timescale with its data and modelled of measured points and its derivative with Figure 7 a showing the first step, Figure 7 b showing the second step and Figure 7 c showing the third step. The parameters obtained are shown in Table 1.

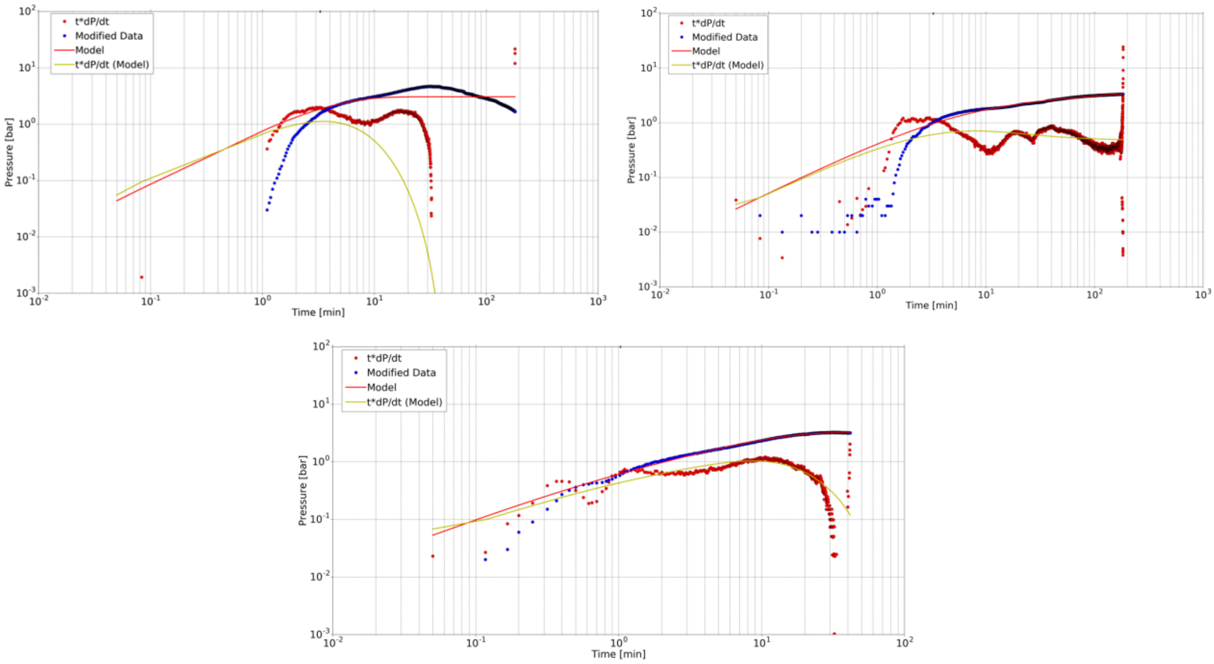

Figure 7: The modelling result of the second multistage injection test a) first step b) second step c) third step

3.3 Multistage Production Test

The multistage production/discharge test basically has the same characteristic as injection test, one difference is the direction of the flow. While the injection test injects a certain mass to the geothermal system, production test discharges a certain mass of the reservoir fluid out of the system. The production test in well SV-26 was conducted on May 17th, 2017, or 422 days after the drilling was completed (Thorgilsson, et al., 2017). The one year interval between drilling completion and the production test is to give the well to heat up and has enough energy to self-discharge, as it was cooled during drilling and injection test.

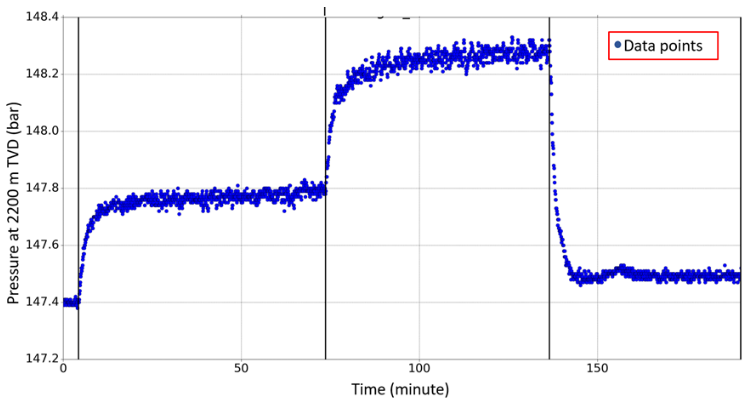

Figure 8: Multistage production test (May 17th 2017)

The pressure tool was lowered to depth of 2200 m TVD. The production test was begun by controlling the valve opening with initial opening corresponded to discharge flowrate of 46.5 kg/s and downhole pressure of 147.39 bar, then to 37.1 kg/s flow rate and downhole pressure of 147.84 bar, flowrate of 22.8 kg/s corresponds to downhole pressure of 148.25 bar and last flowrate of 24.3 kg/s responsibles for pressure of 147.5 bar. All the pressure measurement was plotted against time as shown in Figure 8.

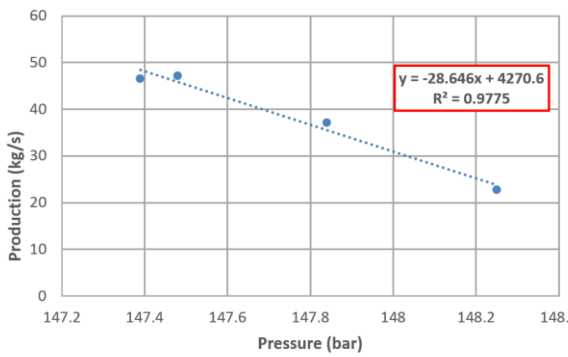

Figure 9: Productivity index estimation of well SV-26 based on the second multistage production test

The same method was applied as the injectivity test where the stabilized pressure was plotted against the production flow rate and a linear trend line with its equation are generated from the graph. As shown in Figure 9, the resulted equation is y = -28.646x + 4270.6. It should be noted here, that the negative value in the generated equation means that it has opposite direction with the injectivity test which means that a certain amount of mass was extracted from the system. The productivity index value is then concluded to be 28.6 kg/s/bar.

The multistage productivity test is also modelled with the same method as the injectivity modelling. The same type of reservoir conditions was also chosen for the modelling, with homogenous porosity, constant pressure boundary, constant wellbore storage and constant skin value. The graphs obtained from the modelling were shown in Figure 10 a, Figure 10 b and Figure 10 c for the first, second and third step respectively. The parameters obtained are shown in Table 1.

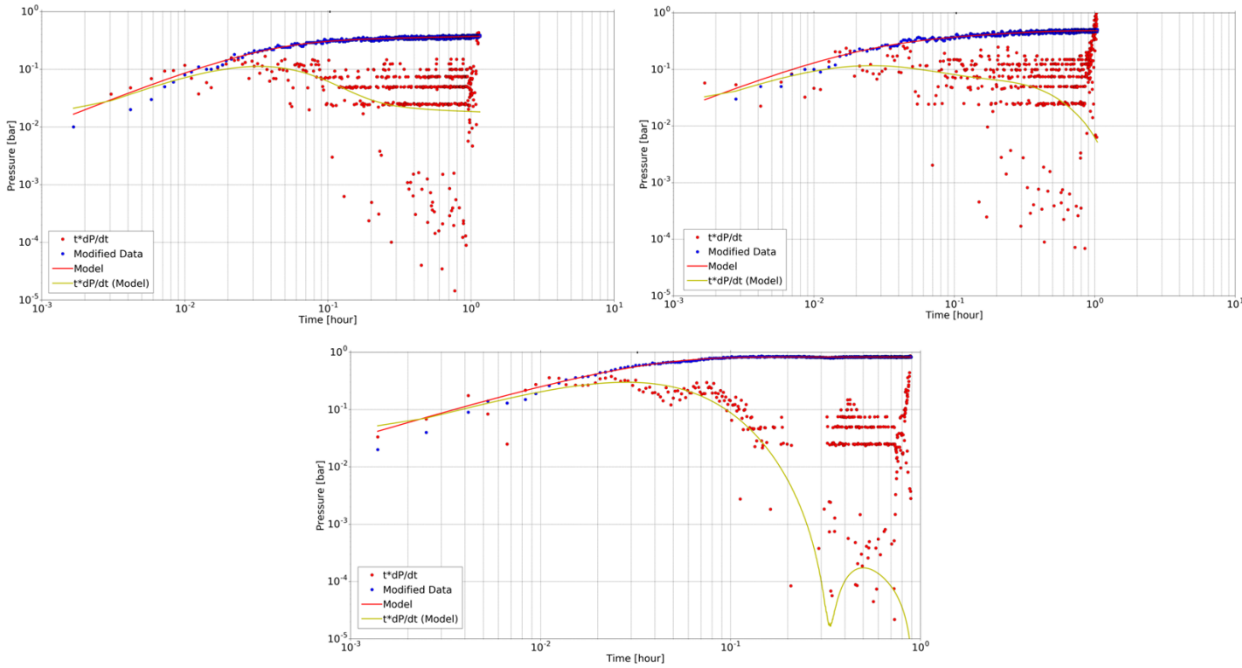

Figure 10: The modelling result of the multistage production test a) first step b) second step c) third step

3.4 Hydrological Model Summary

As shown in the Table 1, the second step of the first multistage injection test modelling resulted in a very high value of injectivity index (33.6 kg/s/bar) compared to the first step (17.1 kg/s/bar) which resulted in average injectivity index of 25.35 kg/s/bar. The modelling result of the first injectivity index does not really give a satisfying result as the coefficient of variation (CV) of the result is very high in a degree of hundreds. This may be the result of disturbed pressure measurement by changing of temperature in the well due to stimulation.

TABLE 1: Reservoir parameters based on well testing analysis with homogenous model of WELLTESTER

Parameter	Injection Test 1 without liner		Injection Test 2 with liner			Production Test 1 with liner		
	Step 1	Step 2	Step 1	Step 2	Step 3	Step 1	Step 2	Step 3
Transmissivity (m^3/ Pa s)	$1.32x10^{-7}$	$1.88x10^{-7}$	$9.76x10^{-8}$	$6.02x10^{-8}$	$1.02x10^{-8}$	$4.34x10^{-7}$	$2.18x10^{-7}$	$1.61x10^{-7}$
Storativity (m/Pa)	$5.96x10^{-8}$	$1.87x10^{-10}$	$8.71x10^{-10}$	$7.00x10^{-8}$	$7.66x10^{-8}$	$7.06x10^{-7}$	$1.38x10^{-6}$	$1.76x10^{-7}$
Radius of Investigation (m)	13.5	10	84.39	258.92	28.69	131.66	25.55	10.00
Skin Factor	0.50	-7.65	-0.91	-3.11	-4.59	4.64	-0.49	-0.70
Wellbore Storage (m^3/ Pa)	$2.09x10^{-4}$	$6.94x10^{-6}$	$2.39x10^{-5}$	$3.77x10^{-5}$	$1.61x10^{-5}$	$3.27x10^{-5}$	$2.63x10^{-5}$	$2.76x10^{-5}$
Reservoir Thickness (m)	403	1.26	6.41	515.30	564.18	5156.55	10064.43	1284.25
Infectivity Index (l/(s bar))	17.1	33.6	11.47	10.31	10.75			
Productivity Index (l/(s bar))						25.31	29.71	29.39
Effective Permeability (m^2)	$3.67x10^{-14}$	$1.67x10^{-11}$	$1.74x10^{-12}$	$1.34x10^{-14}$	$2.07x10^{-15}$	$9.61x10^{-15}$	$2.47x10^{-15}$	$1.43x10^{-14}$

Different from the first injectivity test, the average injectivity index from the WELLTESTER program for the second multistage injection test which is 10.8 kg/s/bar gives a similar result to the previous linear model estimation that gives 11.4 kg/s/bar. The first step gives rather different values compare to the later steps especially in the storativity, reservoir thickness and effective permeability but the first step also has very high values of CVs that's why one should focus more on the result of the second and third step.

The transmissivity of all steps in the second injectivity test gives the value in order of 10^{-8} which is very common for Icelandic geothermal reservoir. The storativity value of the second and the third step also showing values in order of 10^{-8} which is common for liquid-dominated geothermal reservoir while two phase values give value in order of 10^{-5} (Haraldsdóttir, 2009). The effective permeability of the second and third step also resulted in the value order of 10^{-14} and 10^{-15} (1 and 10 milli-Darcy) which is a quite good permeability. The first injectivity test infer effective permeability in the degree of 1000 milli-Darcy which is much higher than in the second test. The difference may relate to the 7" slotted liner not yet been run into the well during the first test. The skin values point to more negative values with more steps meaning that well is cleaned with more injection because it removes all the cutting and drilling mud that might block the feedzone to the reservoir.

The multistage production test modelling resulted in average productivity test of 28.11 kg/s/bar which is similar to the previous estimation of 28.6 kg/s/bar. Comparing to the second injectivity test which was conducted in the same feedzone, the modelling result also gives quite similar results. For example, the effective permeability also gives result in order of 10^{-14} and 10^{-15} m^2 (1 and 10 milli-Darcy) while the transmissivity and the storativity infer in higher values. This is might be due to more than a year interval between the second injection test and the productivity test that gives the well time to heat up and forming larger steam phase than when it's first measured in the injectivity test. The higher productivity compared to the injectivity index also may be affected by the liner holes viscosity effect. It means that when the well is colder, the reservoir fluid will have lower viscosity that makes it more difficult to enter the liner holes and vice versa, when the well is hot with higher viscosity it will be easier to enter the holes.

4. WELLBORE SIMULATION

In this chapter, wellbore simulation will be conducted for well SV-26 to generate output deliverability curve as well as to estimate the relative contribution of two major feedzones in the well. As discussed in chapter 2 of this paper, two major feedzone are found in the well at 1225 and 2200 m TVD. A multistage injectivity test was conducted on the shallow feedzone while a multistage injectivity test and a multistage production test were conducted in the deep feedzone of the well.

The wellbore simulation was conducted with HOLA program developed by Björnsson et al. (1993) with parameters inputted including well design, the reservoir and well properties and most importantly the estimated feedzones properties of the well. In this simulation, heat loss of the system by conduction will be ignored.

The input parameters for the program are obtained from the previous chapters of this paper. Some parameters have to be guessed and changed by trial and error by comparing the result with the measured data from the well. The measured data that will be used for trial and error is the data obtained from multistage productivity test as shown in Table 2.

TABLE 2: Result of multistage productivity test

Parameters	Flowrate (kg/s)	Bottom pressure (bar)	Wellhead pressure (bar)
Initial	46.5	147.4	13.8
Step 1	37.1	147.8	13.8
Step 2	22.8	148.3	13.8
Step 3	47.1	147.5	13.7

Several attempts of trial and error were conducted by changing the feedzones parameters especially the ratio of the productivity of the shallow and the bottom feedzones of the well. The ratios of productivity between the shallow and the deep feedzones that were tried are 1:1, 1:2, 2:1 and 2.5:1. The result of the productivity index and output deliverability are shown in Figure 11, Figure 12, Figure 13 and Figure 14 for productivity ratio of 1:1, 1:2, 2:1 and 2.5:1 respectively.

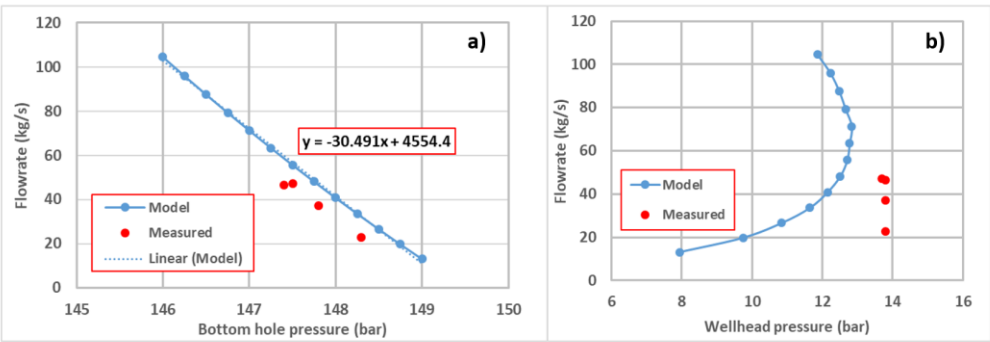

Figure 11: (a) Bottom hole pressure vs discharge flowrate (b) Wellhead pressure vs discharge flowrate result from ratio of shallow and deep feed zone of 1:1

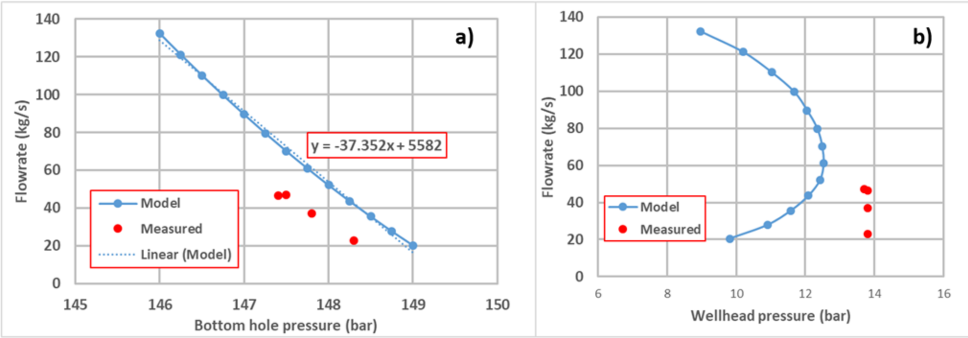

Figure 12: (a) Bottom hole pressure vs discharge flowrate (b) Wellhead pressure vs discharge flowrate result from ratio of shallow and deep feed zone of 1:2

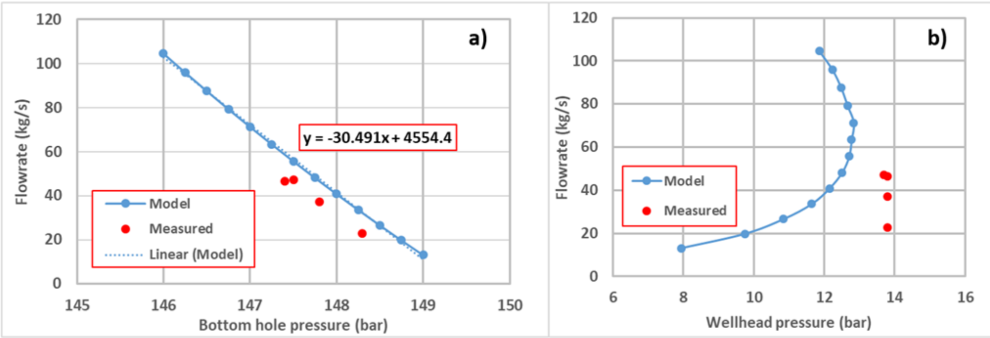

Figure 13: (a) Bottom hole pressure vs discharge flowrate (b) Wellhead pressure vs discharge flowrate result from ratio of shallow and deep feed zone of 2:1

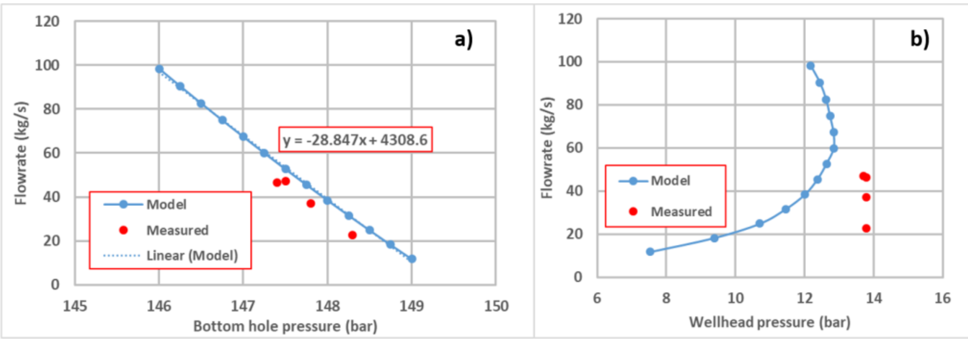

Figure 14: (a) Bottom hole pressure vs discharge flowrate (b) Wellhead pressure vs discharge flowrate result from ratio of shallow and deep feed zone of 2.5:1

All of the picture above especially the productivity of bottomhole pressure were compared with productivity index that previously estimated as shown in Figure 23. In the figure, the resulted productivity index is 28.7 kg/s/bar. Comparing with the resulted bottom hole pressure vs flowrate that are generated from HOLA program, the 4th trial with ratio between productivity of shallow and deep feedzone of 2.5:1 gives the best result with productivity index of 28.9 kg/s/bar.

All of the picture above especially the productivity of bottom hole pressure were compared with productivity index that previously estimated as shown in Figure 9. In the figure, the resulted productivity index is 28.7 kg/s/bar. Comparing with the resulted bottomhole pressure vs flowrate that are generated from HOLA program, the 4th trial with ratio between productivity of shallow and deep feedzone of 2.5:1 gives the best result with productivity index of 28.9 kg/s/bar.

Generating the output deliverability curve that fit the model perfectly is a delicate process. The measured wellhead pressure of the well produce variety of discharge flowrate with only small changes in wellhead pressure which means that the well and reservoir has a very good permeability. The assumption of good permeability of the reservoir is also supported with the fact that the change of the bottomhole pressure is very small with the different discharge flowrate. The almost vertical measured curve is rather hard to be fitted with trial and error with HOLA program even after changing various parameters such as ratio of productivity of the feedzones, enthalpy of the reservoir fluid and even the type of velocity method provided in the program (Orskiszewsky and Björnsson). The best fitted result can be obtained from the program is in the ratio of productivity between shallow and deep feedzones of 2.5:1 as it produces the closest values with the measured values as well as result in the most vertical curve compared to the others.

The almost vertical wellhead output curve also means that the well can actually deliver much higher flowrate than the maximum measured flowrate of 47 kg/s. In Figure 14, which shows the best model, the well can produce some 100 kg/s flowrate of reservoir fluid with wellhead pressure of 12 bar. Assuming 20% of dryness and a conversion of steam to power of 2 kg/s/MWe, the well can produce electricity of 10 MWe.

After the best ratio of productivity is obtained, the resulted modelling data and the measured data for dynamic pressure and temperature with depth are plotted with HOLA program. The resulted plot is shown in Figure 15 together with the well design and mass contribution of each feedzone. From the plot we can see that the flowrate contribution of the shallow and the deep zone is 30.7 kg/s and 14.9 kg/s or 2:1. The end result of ratio of mass flowrate gives rather a different ratio than those of the productivity of the feedzone. This is because the mass flowrate contribution is not only controlled by the productivity of the feedzone but also the difference between the pressure of reservoir and the well.

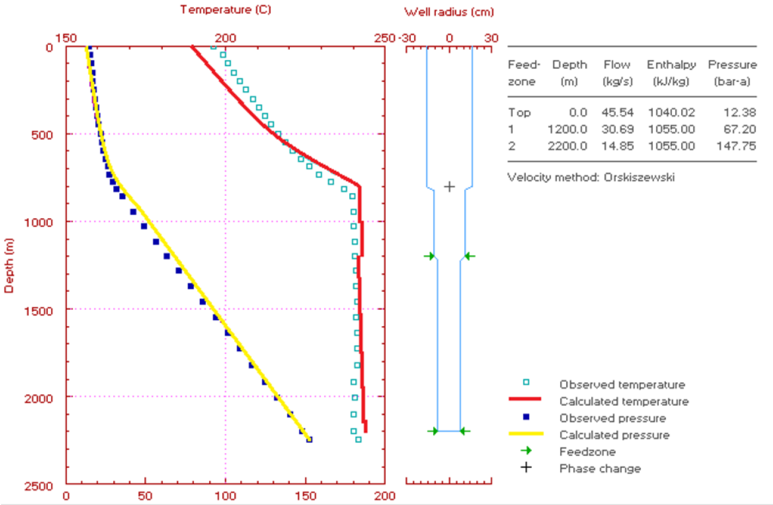

Figure 15: Measured and modelled pressure and temperature data from production test

5. CONCLUSION

Downhole temperature and pressure measurement are one of the most important tools for predicting reservoir parameters condition that will be used later for the next development, resource assessment and modelling of the reservoir system. In this paper, interpretation of downhole pressure and temperature logging was conducted for well SV-26 in Svartsengi, Iceland while the well was being drilled, injected, static and discharge. From the logging analysis, one can obtained a lot of information such as the location of major feedzones which are in 1225 and 2200 m TVD, location of the static water table which is in 425 m TVD, location where the reservoir fluid start to boil which starts from 700 m TVD, the pivot point location in 1350 m TVD which corresponds to 77 bar reservoir pressure and also initial temperature that is predicted to be around 240 °C.

The injection and production tests were conducted to estimate the injectivity and the productivity as well as other reservoir parameters. Two injections test and one production test previously were conducted in well SV-26 were modelled with WELLTESTER program. The average injectivity index for the first injection test is 25.4 kg/s/bar, while the average injectivity index for the second test is 10.8 kg/s/bar and the average productivity index is 28.1 kg/s/bar.

The injectivity and production indexes indicate a very good reservoir permeability. The transmissivity of the reservoir based on the second injectivity test is in the degree of 10^{-8} which is usual for geothermal reservoir in Iceland while the storativity is in the degree of 10^{-8} which indicate a liquid dominated reservoir. Both the transmissivity and the storativity are getting higher in the production test which indicate heating up in the well where more steam are gathering in the well. The skin value also point to more negative values within each step within an injection or production test which indicates that the well is being stimulated and resulted in better permeability. Effective permeability before running the liner has 1000 milli-Darcy compared to one after it was run which significantly decrease to 1-10 milli-Darcy. It could be explained by liner holes viscosity effect in which the colder fluid will have more difficulty entering the liner holes than the hotter fluid which has higher viscosity.

The wellbore simulator was conducted with HOLA program to generate well output curve and to estimate the contribution of the feedzones in the well. The modelling were conducted with trial and error by changing the productivity of the shallow and the deep feedzones of the well and try to fit with the measured productivity from the bottom pressure and wellhead pressure. The best fit was generated from productivity ratio of the shallow and the deep feedzone of 2.5:1 which resulted in flowrate ratio of 2:1 between the shallow and the deep feedzone. The difference of the productivity and the resulted flowrate is due to other factor also control the flowrate for example the difference between reservoir pressure and well pressure. The resulted almost vertical wellhead output curve suggest that the well can produce high flowrate up to 100 kg/s. Assuming the dryness of 20% and conversion steam to power of 2 kg/s/MWe infer in capacity of the well to be 10 MWe.

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