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# Pressure Transient Analysis of an Injection/Fall-off Test using Analytical and Numerical Reservoir Modelling

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**ABSTRACT**

Pressure transient data obtained from an injection/fall-off test are analyzed using pressure transient analysis (PTA) to derive reservoir permeability (k) and skin factor (S). Geothermal pressure transients are commonly interpreted using analytical models which assumes that the fluid flow in the reservoir is isothermal. However, for geothermal reservoirs analysis of pressure transient data is complicated by non-isothermal reservoir conditions. Numerical models to simulate geothermal pressure transients are therefore needed in place of analytical model which was developed mainly for oil and gas reservoirs.

In this study the numerical reservoir simulator TOUGH2 was used to simulate the non-isothermal effects during injection/fall-off tests. The numerical PyTOUGH/TOUGH2 model set-up is demonstrated to represent homogeneous reservoirs, fissured or fractured reservoirs, and layered reservoirs. Pressure transient data generated by these models were used as simulated field data and analyzed using PTA software SAPHIR to derive k and S. A TOUGH2 model setup to run with the non-linear parameter estimation software PEST was also made to demonstrate an automated numerical pressure transient analysis method of the simulated pressure data. The results from SAPHIR (analytical) and TOUGH2-PEST (numerical) were compared to the model values to quantify the difference in k and S. The PTA result shows a good fit on the simulated pressure data for both analytical and numerical models. The numerical models correctly estimate the k and S but the analytical models resulted to a high k and S compared to the model values.

The numerical models were also used on a case study using field data from Leyte geothermal field, Philippines. Field data used are pressure fall-off transients from an injection/fall-off tests performed before and after acidizing of a well. The results of pressure transient analysis are examined to determine the effect of acidizing on the permeability and skin of the reservoir. The results of PTA on the actual field data shows a good fit on the analytical model but poor on the numerical model, both for the pre and post-acidizing injection/fall-off dataset. Numerical results indicate an increase in k but no change in k was obtained from analytical results. Skin factor indicate an increase for both analytical and numerical results. The numerical PTA result is not considered reliable for this PTA due to the poor model fit especially on the fall-off dataset. A number of improvements in the numerical PTA method were identified and is subject for future work.

## 1. INTRODUCTION

After the completion of drilling an injection/fall-off test is commonly performed as part of geothermal well testing to obtain pressure transient data from which reservoir permeability (k) and skin factor (S) of the well can be calculated (Benson and Bodvarsson, 1982). These parameters are important for assessing whether the well will produce at commercial levels. During injection/fall-off tests, the temperature of the injected fluid or injectate is invariably different from the temperature of the in situ reservoir fluid (Sigurdsson et al., 1983). The difference in the fluid temperature between the injectate and the reservoir results in non-isothermal reservoir conditions where the fluid and rock temperature-dependent properties such as density, viscosity, and compressibility vary (Cox and Bodvarsson, 1985). These variations affect the pressure response obtained during injection/fall-off test (Mangold et al., 1979).

Geothermal pressure transient analysis (PTA) using analytical models can give inaccurate derivation of k and S due to the limitations on its governing equation which assumes that the fluid flow in the reservoir is isothermal. Analytical PTA models cannot account the variations in fluid density, viscosity, and compressibility during injection/fall-off test as it only allows specification of one set of fluid properties. In order to simulate geothermal pressure transient, numerical models were developed using the numerical reservoir simulator TOUGH2 (Pruess, 1991). Numerical simulators such as TOUGH2 allows both the reservoir and injectate temperature to be specified (McLean and Zarrouk, 2015a). A standard model set-up was recently developed (McLean and Zarrouk, 2015b) for geothermal PTA using TOUGH2 and PyTOUGH (Croucher, 2011) to generate pressure transient data. The model was applied on a deflagration case study in New Zealand where a pre and post-deflagration pressure transient data was analyzed using analytical PTA SAPHIR$^{TM}$, numerical model TOUGH2, and TOUGH2 inverse modelling using PEST (McLean et.al, 2016). Different numerical model for PTA was recently developed (Guerra and O'Sullivan, 2018) to include dual-porosity and multi-layer models. The generated pressure transient data by the numerical models were analyzed using SAPHIR$^{TM}$ to determine how the analytical PTA handles model complexity that represents actual geothermal reservoirs such as homogeneous reservoirs, fissured or fractured reservoirs, and layered reservoirs. It has been concluded that all SAPHIR$^{TM}$ derived k and S values generated by different models are higher than the specified model values under non-isothermal condition. Analytical model also incorrectly introduced a reservoir boundary effect to match pressure data from some model cases (Guerra and O'Sullivan, 2018).

In this work, different numerical models representing homogeneous reservoir, fissured or fractured reservoir, and layered reservoir are used to simulate an injection/fall-off pressure data designed based from a completion test in Leyte geothermal field, Philippines.

The simulated pressure data are analyzed using analytical PTA software SAPHIR™ and TOUGH2 that utilize the inverse modelling capability of the software PEST (Doherty, 2005) to automate the non-linear regression. The PTA result on the simulated pressure data using analytical and numerical method will be compared to the model values. Particular focus will be on the shape of the derivative plot, reservoir permeability (k), and skin factor (S). A case study using an actual field data from an injection/fall-off tests performed before and after acidizing a well will also be conducted. The PTA results obtained from analytical and numerical method will be examined to determine the effect of acidizing on the permeability and skin of the reservoir.

## 2. BACKGROUND

After drilling is completed, the well is tested to gather baseline well test data such as temperature and pressure profiles, potential feed zones, injectivity index, reservoir permeability (k), and skin factor (S). A completion test is considered as one of the most important tests to be conducted to characterize the well and to determine how the well will be utilized. In this research, injection/fall-off tests are discussed as part of the completion test. A completion test will include a water-loss survey, an injectivity test, and a pressure fall-off test. Pressure transient data can be obtained during the pressure fall-off test.

### 2.1 Pressure transient analysis (PTA) of an injection/fall-off test

PTA is the analysis of pressure changes over time resulting from a change in the rate of production or injection. The measured pressure response from the well is used as a representation of the actual reservoir response and hence we treat the flow rate transient as input and pressure transient as output (Horne, 1995). The pressure response characterizes the ability of the fluid to flow through the reservoir to the well, which provides a description of the reservoir under dynamic conditions. From the PTA, it is possible to determine the following properties: reservoir permeability (k), reservoir heterogeneities (fractures, layering), reservoir boundaries, reservoir pressure, production potential (productivity index, skin factor), and well geometry (Bourdet, 2001).

Conventional PTA makes use of graphical representation or type curves to match the data (Figure 1) e.g. semi-log, MDH, and Horner plots. The Bourdet derivative introduced in 1983 using slope of the semi-log plot displayed on the log-log plot enhances the diagnostic capability, resolution, and reliability of modern PTA (Houzé, et.al, 2012). However, well test interpretation using conventional method has poor resolution and accuracy due to the fact that the results will rely mostly on the reader's interpretation (matching by eye) and maybe subjective depending on the reader's perspective. In addition, manual computation is prone to human error and takes a long time to perform.

With the development of computers in the mid 80's, type curve techniques become obsolete. Computer based software and the use of more complex analytical models for PTA became more popular. A sample of the application of PTA software (SAPHIR™) to analyze pressure transient data from an injection/fall-off test is shown in Figure 1. The left figure shows the pressure history matching while the right figure shows the pressure derivative matching. Analytical models for PTA are mainly developed for oil and gas industry, which means that they only work well in a low temperature environment and for simple reservoir structures. The use of analytical models to geothermal PTA is problematic due to many analytical assumptions which are violated in the geothermal environment (McLean et.al, 2016). Analytical models for geothermal PTA only allow the specification of constant fluid properties. It does not account for the non-isothermal effects during injection/fall-off test where there is a large difference in temperature between the cold injectate and hot reservoir.

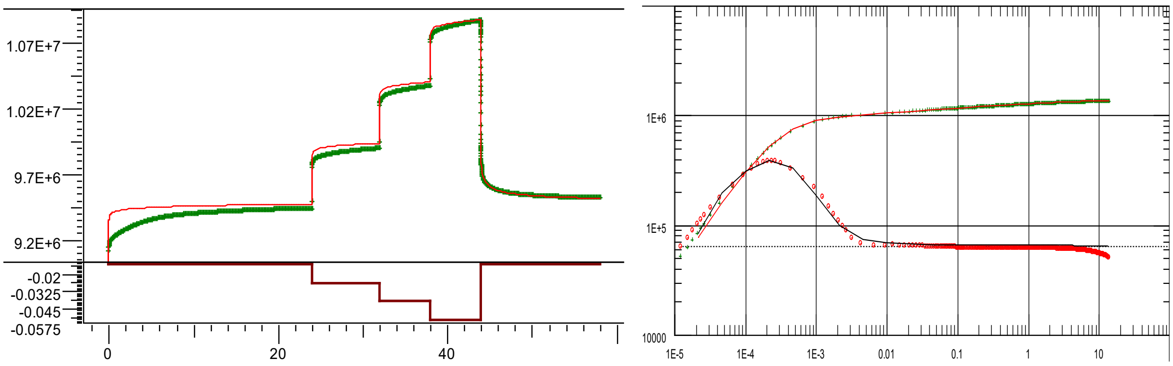



**Figure 1: Computer-based matching using the analytical PTA software SAPHIR™**

### 2.2 Effects of Non-isothermal reservoir conditions on analytical PTA using SAPHIR™

Recent study on the effects of non-isothermal reservoir condition on analytical PTA (Guerra and O'Sullivan, 2018) which focus on reservoir permeability (k) and skin factor (S) concluded that the non-isothermal effect on the derived k are less significant at lower temperature but more significant at higher temperature. The temperature effect on the derived k mirrors the dependence of the dynamic viscosity (μ) on temperature as shown in Figure 2. These effects demonstrate that the less viscous the fluid is, the faster the formation fluid will react to a local pressure disturbance. The non-isothermal effect on the skin factor (S) resembles a positive skin. The derived S is more sensitive to change for higher ΔT (difference between injectate and reservoir temperature) and less at lower ΔT. The skin effect also amplified using a positive model S but then countered with a negative model S. Overall, all SAPHIR™ derived k and S values are higher than the specified model values under non-isothermal condition. This was demonstrated using different numerical models including single-layer, multi-layer, and dual-porosity models.

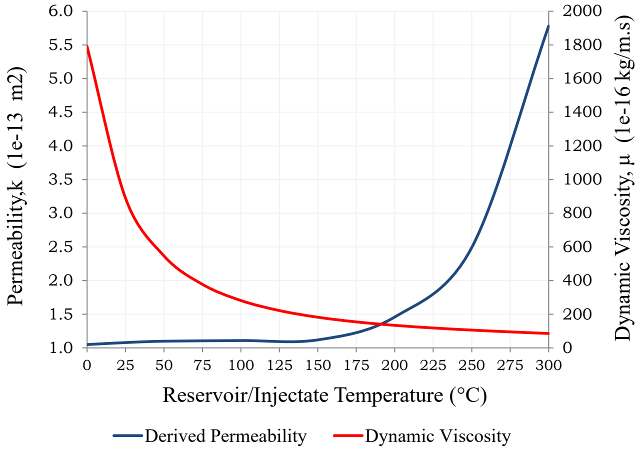



**Figure 2: Relationship of reservoir permeability and dynamic viscosity with respect to temperature (Guerra and O'Sullivan, 2018a)**

### 2.3 Numerical modelling of geothermal pressure transient

The issue of non-isothermal effects during an injection/fall-off test can be addressed with numerical reservoir simulator by allowing both the temperature and fluid properties of the reservoir and injectate to be specified. A standard model set-up has recently been developed for this purpose (McLean and Zarrouk, 2015a). This model represents an infinite, homogeneous uniform porous geothermal reservoir. The general setup is for a single-layer radial grid with well block, skin zone, and reservoir zone. Additional models have been developed to include multi-layer and dual-porosity model (Guerra and O'Sullivan, 2018). The model utilizes AUTOUGH2 (Yeh et.al, 2012), a University of Auckland version of TOUGH2 (Pruess, 1991). The model was written in python codes utilizing PyTOUGH (Croucher, 2011) to automate the use of TOUGH2.

Schematics of a single-layer and multi-layer model are shown in Figure 3. Key model parameters are given in Table 1. In a single-layer model, the reservoir is represented as a single-layer with radially symmetric mesh with well located in the center. The radius of the well block is 0.10795 meters derived from a standard 8-1/2" wellbore diameter for a 7" liner. The skin zone is composed of 50 blocks which are logarithmically spaced. The radial extent is 5 meters (at the 50$^{th}$ block) with layer thickness similar to the reservoir zone. The permeability of the skin zone is calculated depending on the skin factor input using the following equation.

$$k_s = \frac{k_r}{\left(1+\left(\frac{s}{\ln\left(\frac{r_s}{r_w}\right)}\right)\right)} \tag{1}$$

where $k_s$, $k_r$, S, $r_s$, $r_w$ are skin zone permeability, reservoir permeability, skin factor, skin zone radius, and well radius, respectively.

The reservoir zone consists of 100 blocks which are logarithmically spaced. The radial extent of the reservoir zone is 20 km (at the 150$^{th}$ block). The layer thickness is set to 100 meters. In reality, reservoir permeability varies over the depth of the reservoir so using a high value for layer thickness will tend to average the different permeability over the whole layer. Reservoir porosity is set to 0.1 while reservoir permeability will depend on the user input. Other parameters such as compressibility, volume, and heat capacity come from TOUGH2 default values.

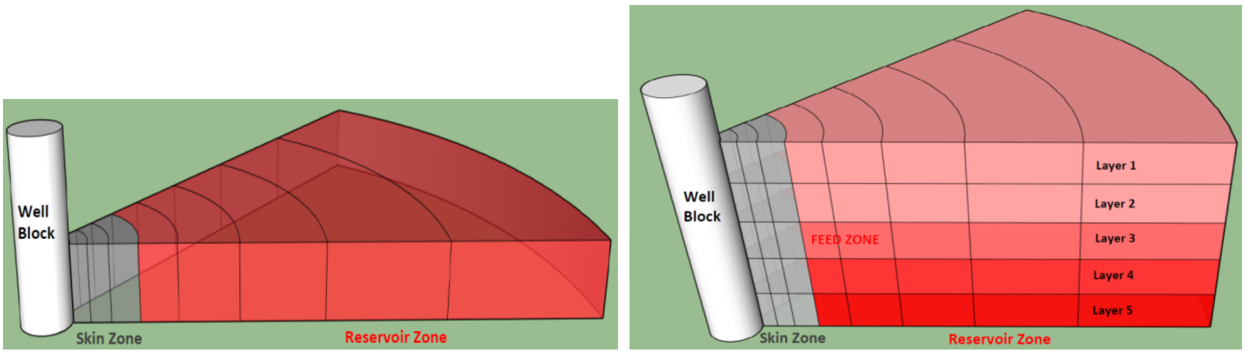



**Figure 3: Schematic of a single-layer radial grid model (left) and multi-layer radial grid model (right) (Guerra and O'Sullivan, 2018a)**

In the multi-layer model, the reservoir is represented by five layers and a radially symmetric mesh with the well located in the center and the major feed zone located in the 3$^{rd}$ layer. The major feed zone layer is represented by a high permeability blocks with other layers have very low horizontal permeability and moderate vertical permeability. The objective of using the multi-layer model is to account for the presence of different lithologic layers that may affect pressure transient data during injection/fall-off test. Using this model, we can investigate the effect of reservoir layering on pressure transient. The well block, skin zone, and reservoir zone is similar to a single-layer model but with five (5) layers.

**Table 1: Single-layer and Multi-layer radial grid model parameter (Guerra and O'Sullivan, 2018a)**

| SECTION | PARAMETER | VALUE |
|---|---|---|
| Well Block | well radius | 0.10795 m |
| | volume | 81.4 $m^3$ |
| | compressibility | $6 \times 10^{-8}$ $Pa^{-1}$ |
| | porosity | 0.9 |
| | permeability | *3 orders of magnitude higher than reservoir permeability* |
| Skin Zone | # of blocks | 50 |
| | width | 5 m |
| | porosity | 0.1 |
| | skin factor | 0 |
| Reservoir Zone | # of blocks | 100 |
| | radial extent | 20 km |
| | porosity | 0.1 |
| | permeability | *user input* |
| | layer thickness | 100 m |

The dual porosity model represents a reservoir that is made up of rock matrix blocks with high storativity but low permeability while the well is connected by natural fissures of low storativity but high permeability (Houzé, et.al, 2012). Instead of the fluid flowing through the matrix blocks, it has to enter the fissure system first. Figure 4 shows a representation of dual porosity reservoir model. The dual porosity model was applied to both single-layer and multi-layer radial grid model to represent fissure/fractured reservoirs. The model will enable us to investigate the pressure transient response when two different media are involved in the flow process: a higher permeability medium that produces fluid into the well, and a lower permeability medium that recharges the higher permeability medium. Dual porosity parameters (Table 2) are applied using MINC (Multiple Interacting Continua) method of TOUGH2.

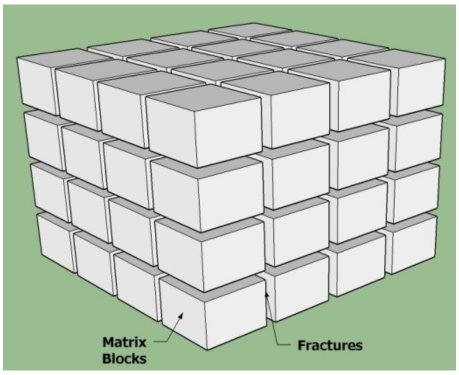



**Figure 4: Dual porosity reservoir model**

**Table 2: Dual porosity reservoir model parameter (Guerra and O'Sullivan, 2018a)**

| SECTION | PARAMETER | VALUE |
|---|---|---|
| Skin Zone and Reservoir Zone | Matrix rock permeability | 1e-18 $m^2$ |
| | Fractured rock porosity | 0.7 |
| | # of matrix | 3 |
| | Spacing | 25 m |
| | Volume | 0.01 $m^3$<br>0.19 $m^3$<br>0.80 $m^3$ |

## 3. PRESSURE TRANSIENT ANALYSIS OF THE SIMULATED PRESSURE DATA

The test models are set-up based on an injection/fall-off test program of a production well in Leyte geothermal field, Philippines. The program includes the injection/fall-off tests which is the focus of this study. The test is simulated using different numerical models, in each case generating a model pressure response.

### 3.1 Simulation of an Injection/Fall-off Test

An injection/fall-off test program will be simulated in the numerical model by injecting cold water (50°C) into a hot reservoir (260°C). The injection test had four increasing rates (5 bpm, 10 bpm, 15 bpm, and 20 bpm) followed by a two-rate pressure fall-off test by reducing the injection to 5 bpm for 8 hours. In an injection/fall-off tests, there are important data points for PTA during the fall-off test where the pressure is rapidly decreasing during the early-time transient behavior and slowly decreasing at a late-time behavior. Closely-spaced time steps are required if there is a rapid pressure change while longer time steps can be used when the pressure change is slow. In view of this requirement, the simulation run was divided into two-stages so that finer time stepping can be imposed at the start of the fall-off period (Figure 5).

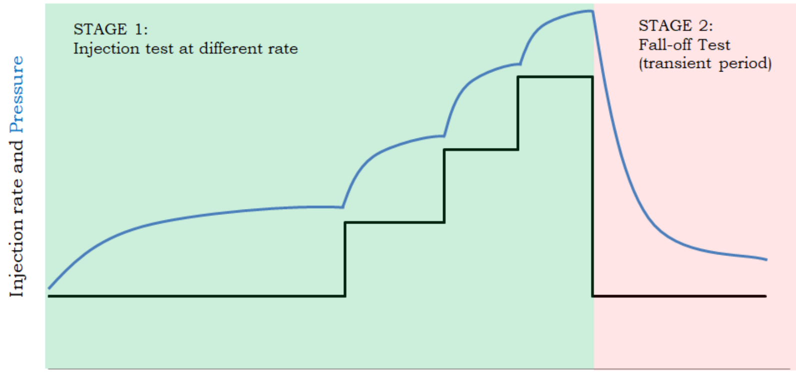



**Figure 5. Schematic of two-stage simulation process for accurate time-stepping (Guerra and O'Sullivan, 2018b)**

During the injection test, the simulation is set to have a constant time step of 60 seconds and a maximum step size of 60 seconds. Injection test data will not be analyzed so time stepping on this stage is not critical. For the fall-off test, the simulation is set to have a predefined time step beginning at 0.001 seconds and increasing by 1 order of magnitude thereafter until it reaches 10 seconds (maximum step size). Each time step is set to capture 10 data points before increasing. In this simulation, the closely-spaced time step is set at the beginning of Stage 2 where there is a rapid decrease in pressure observed. A longer time step is set at the time when the pressure is slowly decreasing. A predefined time step can be set in TOUGH2 using *dat.parameter[timestep]*. Injection mass flow rates (in kg/s) are computed based on the assigned temperature and its corresponding density.

### 3.2 Numerical reservoir models for geothermal pressure transients

Four numerical reservoir models which represent different types of geothermal reservoirs are used for the injection/fall-off test simulation:

- Single-layer, single porosity model (SLSP)
- Single-layer, dual porosity model (SLDP)
- Multi-layer, single porosity model (MLSP)
- Multi-layer, dual porosity model (MLDP)

The SLSP is a numerical model that has been used by various researchers for generating pressure transient analysis (Benson and Bodvarsson, 1982; McLean and Zarrouk, 2015a). This model represents a homogeneous uniform porous reservoir. The SLDP is similar to SLSP with the addition of matrix blocks to represent the dual porosity reservoir. This model represents a fissured/fractured reservoir. The MLSP is a multi-layer model with the feed zone located at the third layer. The permeability of other layers are set to permeabilities different from the feed zone. This model represents uniform porous layered reservoir. The MLDP is similar to MLSP but with the addition of matrix blocks to represent dual porosity reservoir. This model represents a fissured/fractured reservoir with layering of different reservoir permeability.

In this simulation, the models are assigned to have reservoir permeability of 30 mD with zero skin. For multi-layer model, the third layer is assigned with permeability of 30 mD while other layers have lower permeability than the feed zone. These values are chosen to give a pressure derivative plot that highlights the resemblance of the reservoir model that generates them (e.g. a dip and a hump on pressure derivative plot represents dual porosity reservoir).

### 3.3 TOUGH2 inverse modelling using non-linear parameter estimation PEST

Inverse modelling is a numerical procedure where values of the model parameters are inferred from measurements of some observable quantities (Tarantola, 2015). The technique involved successive forward simulations and systematic updating of parameters until certain criteria are met for matching the observed data (Villacorte and O'Sullivan, 2012). PEST can adjust input parameters until the response of the model is optimized. It can also be used with models written in any programming language and can be used for machines that operates with DOS, Microsoft Windows, or UNIX.

In this study, TOUGH2 inverse modelling is conducted using PEST to automate the non-linear regression. The input required by PEST includes template file, instruction file, and control file. Parameter data from which the initial guess will be inputted and the observation data is located in the control file. All measured data are set to have equal weights to remove biased on the model fit. The non-linear regressions of all models have two main variable parameters (reservoir permeability and skin). The number of adjustable parameters depends on the type of the reservoir model used (SLSP = 2, SLDP = 2, MLSP = 12, MLDP = 12). A number of different inversion were run using initial guess of 10x, 100x, 0.1x, and 0.01x from the actual model value that generates the pressure transient data. This is conducted in order to investigate which starting point of the adjustable parameters will give the best model fit and will obtained the closest value to the actual k and S. The optimization is set to 20 iterations only to limit the duration of PEST runs.

### 3.4 Results and discussion on the PTA of the simulated data

The analytical PTA software SAPHIR$^{TM}$ was used for the analytical analysis of the simulated pressure response generated by the four models (SLSP, SLDP, MLSP, and MLDP). The SAPHIR$^{TM}$ version used in this study is v5.20. All SAPHIR$^{TM}$ analyses were based on the reservoir fluid properties, not on the injectate fluid properties. The input parameters in SAPHIR$^{TM}$ such as well radius, porosity, pay zone, reservoir temperature, reservoir pressure, etc. are the same values used in the numerical model parameters. The model k and S were then estimated from the simulated pressure response generated by the models using TOUGH2 inverse modelling utilizing the non-linear regression parameter estimation PEST.

All four models are available for analytical analysis using SAPHIR$^{TM}$ and for inverse modelling using TOUGH2-PEST. Analytical PTA method uses the non-linear regression capability of SAPHIR$^{TM}$. For numerical method, an inverse modelling process of fitting models to the simulated data to estimate the model parameters is used using TOUGH2-PEST combination. An injection/fall-off pressure history plot and pressure derivative plot generated from the models are shown in Figures 6 to 9. Match from the analytical and numerical model are also displayed in the plots. For numerical model using different inversion, the initial guess with the best model fit is displayed.

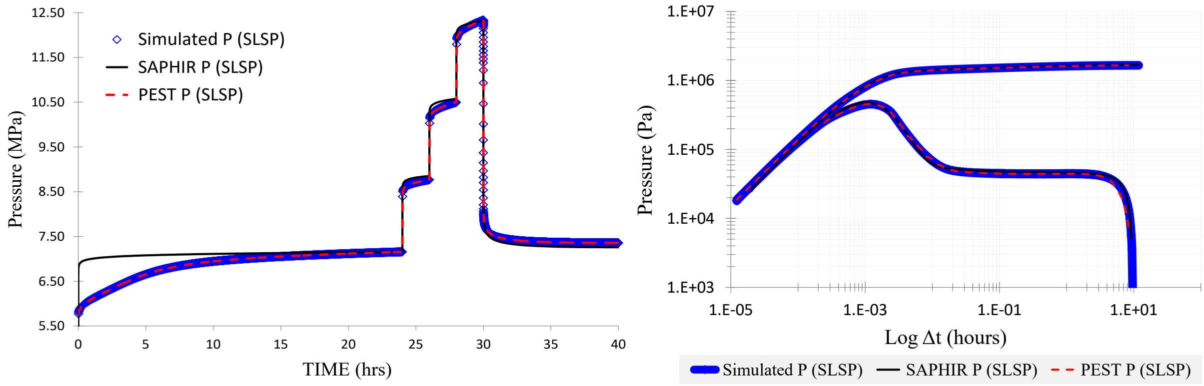



**Figure 6. Single-layer, single porosity model pressure history plot (left) and pressure derivative plot (right)**

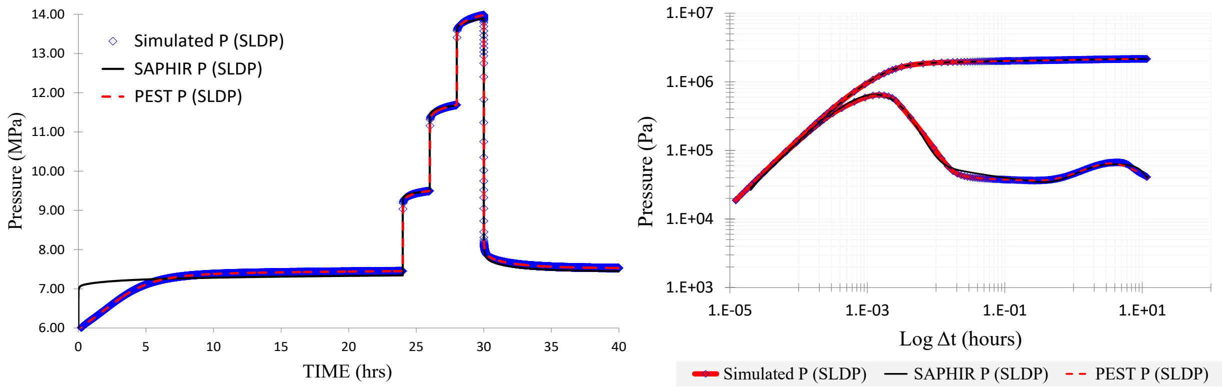



**Figure 7. Single-layer, dual porosity model pressure history plot (left) and pressure derivative plot (right)**

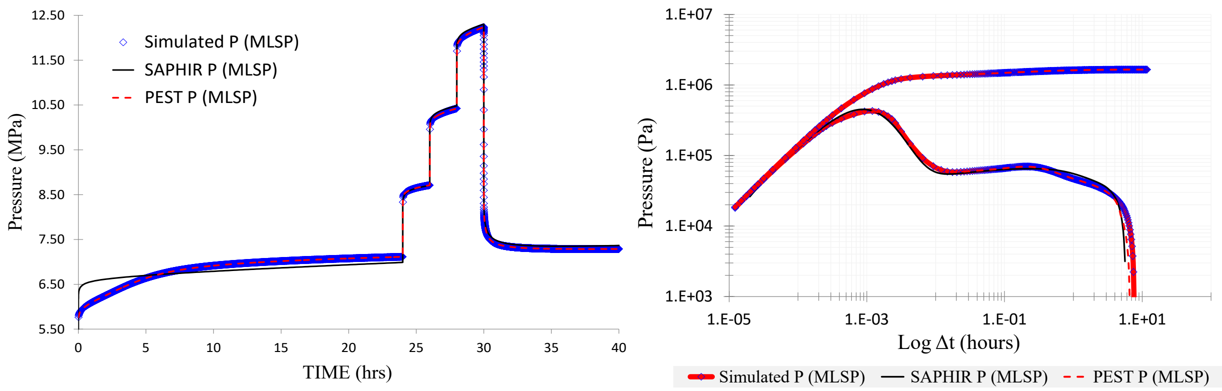
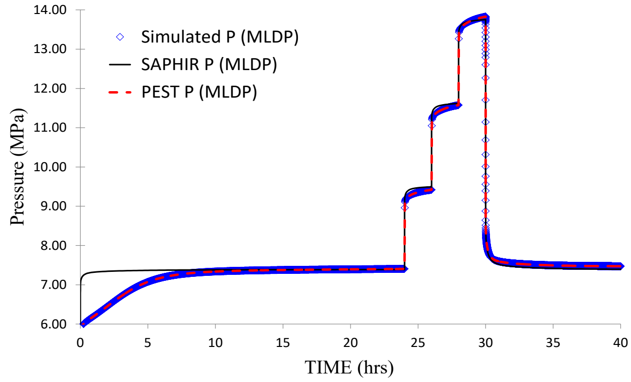



**Figure 8. Multi-layer, single porosity model pressure history plot (left) and pressure derivative plot (right)**



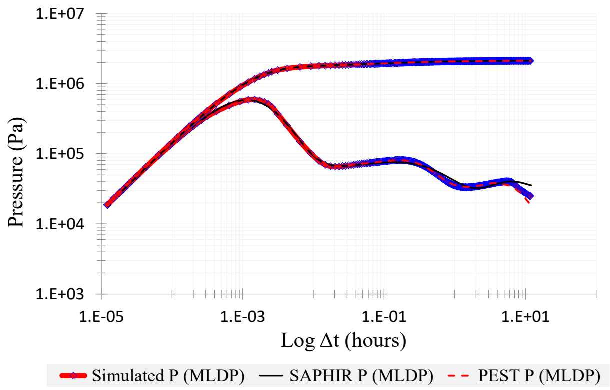




**Figure 9. Multi-layer, dual porosity model pressure history plot (left) and pressure derivative plot (right)**

In general, history plot and derivative plot of the four models shows a good model fit from analytical and numerical models except for the early time injection where the analytical model has difficulty matching. The derivative plot starts in the wellbore storage (WBS) flow regime with a unit slope before transitioning to a period of infinite radial acting flow (IARF) indicated usually by a zero slope line but may vary depending on the reservoir model used. The transition from WBS to IARF which normally last 1-1/2 log cycles characterizes the skin effect on the near wellbore. The change in slope after the IARF indicates the boundary effect of the reservoir. The skin factor is characterized based on the steepness of the derivative hump before IARF. The higher the steepness of the hump means a higher skin factor. Reservoir permeability is obtained from the period of IARF. Different reservoir model will have a different permeability line on the pressure response with respect to the logarithm of time. In SLSP, the derivative plot shows a flat IARF line. This resembles a homogenous reservoir where the derivative stabilizes and is flat at a level related to the permeability. In SLDP, the derivative plot shows a dip followed by a hump (S-shaped) in the IARF period. This resembles a dual porosity reservoir where the initial portion of the curve represents a homogeneous behavior resulting from the depletion of the most permeable medium (fissure system). A transition follows as the second media (matrix blocks) starts to provide pressure support in which the pressure in the two media tends to equilibrate. Another homogeneous behavior assumes again as a result of the depletion of both media. In MLSP, a transitional dip followed by a hump similar to dual porosity model is shown in the IARF period. This resembles a double permeability or layered reservoir where the lower permeability layer acts as the matrix blocks of the dual porosity system and can produced by cross flowing to the high permeability layer (fissure system) after depletion. The MLDP derivative plot shows a complex system in the IARF period. The pressure response behavior resembles a dual porosity reservoir with double permeability effect due to reservoir layering. Two S-shaped curves were shown in the IARF period which represents the combination of a dual porosity and double permeability response. All models show a boundary effect different from an infinite boundary from which the pressure response is generated. As discussed by Guerra and O'Sullivan (2017a), the non-isothermal effect on the reservoir boundary is caused by the pressure change at zones of different temperatures that resembles a permeability boundary. This is an effect of the thermal discontinuity due to non-isothermal reservoir condition during an injection/fall-off tests.

The estimated parameters obtained for all model fits are summarized in Table 3. The main parameter of interest is the reservoir permeability (k) and skin factor (S). The analytical reservoir model that is used to fit the pressure response is also included in Table 3. The numerical model fit displayed in Figure 6 to 9 comes from the initial guess of 10x of the model value as this inversion gives the best model fit. All estimated k and S using different inversion of 10x, 100x, 0.1x, and 0.01x is also tabulated in Table 3. For multi-layer models (MLSP and MLDP), the estimated k and S from the model fit comes from the x and y-axis of the third layer (feed zone) model grid.

**Table 3. Model parameters obtained from analytical (SAPHIR™) and Numerical (TOUGH2-PEST) method**

| Numerical Model | Model value | Analytical (SAPHIR™) | | | Numerical (TOUGH2-PEST) | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | | *Value* | *Difference* | *Reservoir model match* | *10x* | *100x* | *0.1x* | *0.01x* | *Difference* |
| *Reservoir Permeability (mD)* | | | | | | | | | |
| SLSP | 30 | 69.0 | **130%** | Homogeneous | 30 | 30 | 30 | 30 | **0%** |
| SLDP | 30 | 49.4 | **65%** | Double porosity | 30 | 30 | 30 | 30 | **0%** |
| MLSP | 30 | 45.6 | **52%** | Double permeability | 30 | 36 | 30 | 30 | **0%** |
| MLDP | 30 | 39.7 | **32%** | Double permeability | 30 | 36 | 14 | 10 | **0% - 66%** |
| *Skin Factor* | | | | | | | | | |
| SLSP | 0 | 10 | **10** | Homogeneous | 0 | 0 | 0 | 0 | **0** |
| SLDP | 0 | 8.5 | **8.5** | Double porosity | 0 | 0 | 0 | 0 | **0** |
| MLSP | 0 | 7.5 | **7.5** | Double permeability | 0 | 0 | 0 | 0 | **0** |
| MLDP | 0 | 9.3 | **9.3** | Double permeability | 0 | 0 | -2 | -3 | **0 - 3** |

### 3.5 Observation on the comparison of k and S between analytical and numerical method (simulated data)

Reservoir permeability (k) derived from the analytical method is higher than the actual model value with percent difference ranging from 32% to 130%. In numerical method, the estimated k perfectly matched the model values at different inversion except for

MLDP with percent difference ranging from 0% to 66%. The 66% comes from the 0.01x inversion. The MLDP model has 50 parameters with 12 of them being adjusted by PEST to match the model pressure response. Given that MLDP has a large number of parameters compared to other models, simulation for MLDP takes a lot of time and iteration. Since the optimization is set to 20 iterations only, parameter estimation is limited. PEST can possibly match the model k if set to more than 20 iterations. The optimization for all models is set to 20 iterations only to limit the simulation runs and for consistency. Result on MLDP suggests that it is better to overestimate the initial guess than to underestimate.

Skin factor derived from analytical method is higher than the model value ranging from 7.5 to 10. This discrepancy is attributed to the non-isothermal effect on the derivative hump which resembles a positive S that analytical model was not able to account. Numerical method was able to match the S for all models at different inversion except for MLDP at 0.1x and 0.01x inversion. Similar to the estimated k of MLDP that was not perfectly matched, additional iteration for the simulation is needed to match the model S or just overestimate the initial guess rather than underestimate. Numerical models are able to account the non-isothermal effect and for this reason the results from numerical method was able to match the model S.

## 4. CASE STUDY: PRE AND POST-ACIDIZING INJECTION/FALL-OFF TESTS OF WELL X IN LEYTE GEOTHERMAL FIELD, PHILIPPINES

### 4.1 General acidizing process

Acidizing is a chemical stimulation method that is used to increase or regain the production loss of a well due to mineral blockage/deposition inside the production casing or within the formation. Mineral deposition includes amorphous silica, calcite, anhydrite, and sulfides. The main objective of the acid treatment is to dissolve these minerals to regain the effective wellbore diameter and to restore the permeability within the formation (Malate et.al, 1998). Mineral deposition within the formation is normally interpreted as positive skin which suggests that there is a near wellbore damage.

Acidizing is carried out either pumping the acid from the wellhead, or by injecting the acid through a pipeline or a coiled tubing. Acid injection from the wellhead is normally used if the target mineral to dissolve is within the production casing. Acid injection through a tube is used to accurately target the depth of concern, normally at the permeable zones to dissolve minerals within the formation.

### 4.2 Pre and Post-acidizing injection/fall-off tests of Well X

Well X is a production well located in Leyte geothermal field, Philippines. After four years of its production, a decline in MW output of the well was observed. Blockages inside the wellbore were also recorded at several depths. Based on the root cause analysis, mineral blockage is the most likely cause of the output decline of well X. A mechanical clearing method within the wellbore was conducted using broaching tools where 3 out of 4 permeable zones were successfully cleared out. The output improved initially by 1 MW but it returned to its pre-broaching output after a few weeks of utilization. A bullhead acidizing (acid injection at the wellhead) was then programmed to clear the well of silica deposition within the production casing that was not cleared-out during the broaching operation and those deposited in the surrounding formation. The acid stimulation is expected to regain the well's loss output due to mineral blockages inside the wellbore.

Prior to acid injection, an injection/fall test was conducted to gather baseline welltest parameters such as injectivity index, reservoir permeability (k) and skin factor (S). The injection test was carried out using injection rates of 10 bpm, 15 bpm, and 20 bpm. Pressure fall-off test was carried out by reducing the injection rate from 20 bpm to 5 bpm. A surface read-out pressure-temperature-spinner (PTS) tool was used to record the pressure response inside the wellbore at the specified setting depth. During the 20 bpm injection of the pre-acidizing injection test, it was observed that the pressure response is similar to the 15 bpm injection. This indicates a problem with the pump utilized during the tests. Based on the pre-acid pressure history plot, the water pump encountered a problem while transitioning from 15 bpm to 20 bpm.

After the acid injection, a post-acidizing injection/fall-off test was conducted to check the effect of acidizing on the injectivity index, k, and S of the reservoir. Similar injection rates were utilized for this test with no problem encountered on the pumps. Similar setting depth for the PTS tool was used for consistency on the obtained pressure response. Figure 10 shows the downhole pressure obtained and the pumprates used during the pre-acidizing and post-acidizing injection/fall-off test.

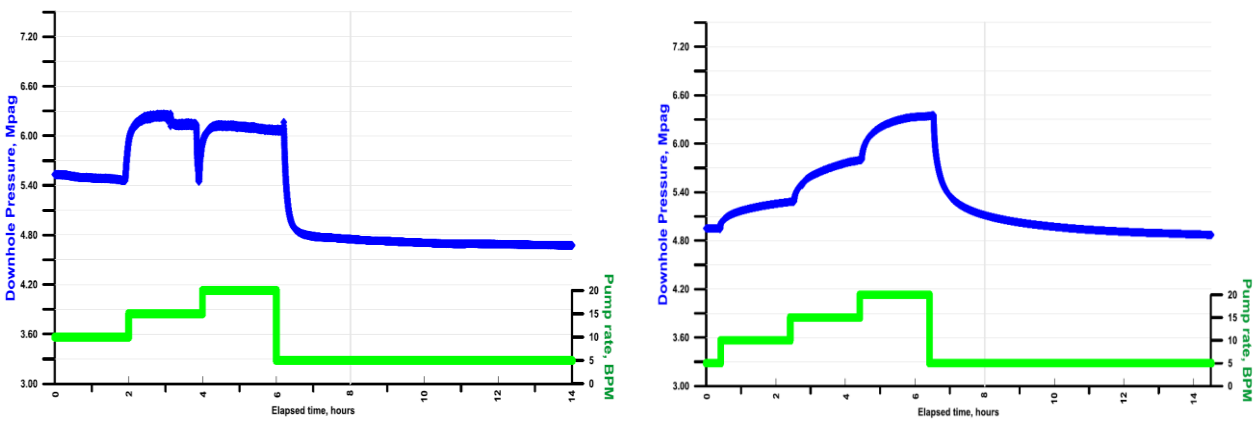



**Figure 10. Downhole pressure during pre-acidizing (left) and post-acidizing (right) injection/fall-off test**

### 4.3 Results and discussion on the PTA of the actual field data

Pressure transient analysis (PTA) for the pre and post-acidizing was conducted in order to determine the effect of acidizing. PTA is undertaken using both the analytical models (SAPHIR™) and the two numerical models corresponding to the dual porosity system discussed in Section 3. Both the pre and post-acidizing injection/fall-off test lasted for about 14 hours. Only the pressure fall-off (PFO) dataset of 8 hours is subjected to PTA. Based on the observation on the shape of the pressure derivative on the pre-acidizing test (Figure 11) in the context of published derivative shapes (Horne, 1995; Houzé, et.al, 2012), the dip and rise (S-shaped) resembles both the dual porosity reservoir response, and a single sealing fault boundary response. The pressure derivative of the post-acidizing test included in Figure 11 shows a rise in the pressure response higher than the derivative hump of the skin. The shallow dip and the rise in the pressure derivative seen in the pre-acidizing plot is also evident in the post-acidizing data hence similar model was used for the post-acidizing PTA.

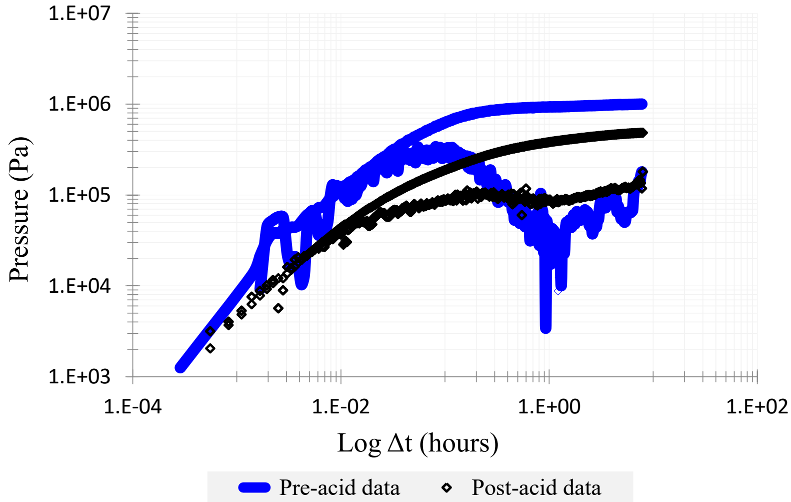



**Figure 11. Pressure derivative plot for pre-acid and post-acid pressure fall-off datasets**

The field dataset of pre and post-acidizing injection/fall-off tests together with the analytical and numerical model fit is shown in Figure 12. The pressure derivative model fit using analytical models is shown in Figure 13. The estimated parameters obtained for all the model fits are summarized in Table 4. The parameters for comparison are the reservoir permeability (k) and skin (S).

For analytical method, the dual porosity reservoir with infinite boundary, and homogeneous reservoir with fault boundary were used. Both analytical models show a good fit in the fall-off period for both the pre and post-acidizing datasets. However the data for the injection period was not perfectly matched. Since the reservoir permeability (k) and skin (S) will be obtained in the derivative plot (Figure 13), the fall-off period dataset was prioritized to fit than the injection dataset. With the analytical method, both the fall-off dataset and derivative plot obtained a good model fit.

For the numerical method, two numerical reservoir models were used, namely, the Single-layer dual-porosity model (SLDP), and the Multi-layer dual-porosity model (MLDP) both of which have infinite boundary. Unfortunately, the model with the lowest value of objective function after the PEST inversion for both the numerical models (SLDP and MLDP) were unable to perfectly match the field datasets. It is presently unclear why this method is not performing satisfactorily enough for this real world data. Nonetheless future improvements will be implemented with the TOUGH2-PEST setup which include adding the pressure derivative data as part of the observation, putting more weights in the pressure fall-off data so that PEST prioritizes matching of that part of the test, adding reservoir pressure and boundary parameters as adjustable parameters, using different initial guesses for the parameters and setting more inversion iterations in PEST.

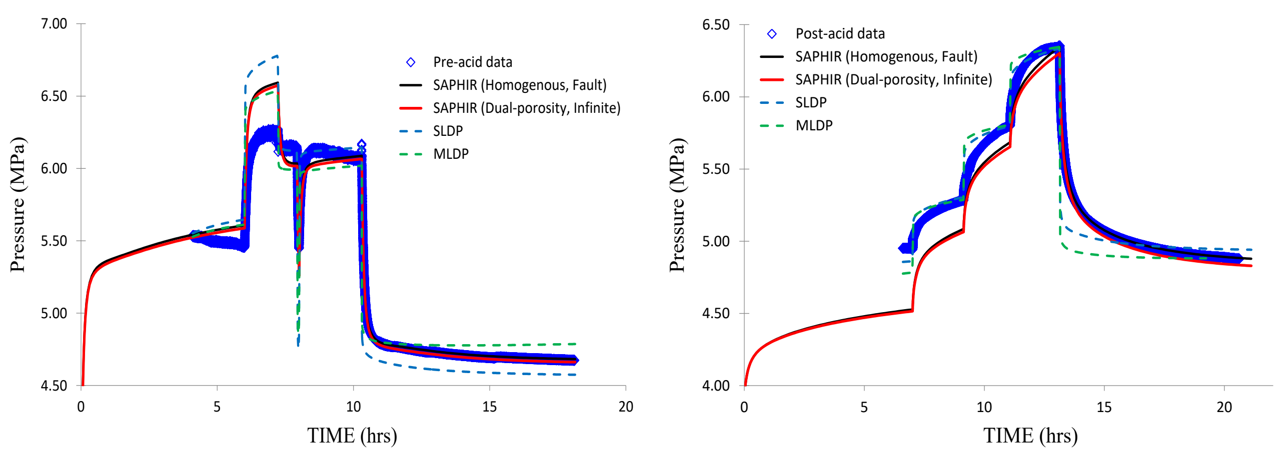



**Figure 12. Field dataset of pre-acidizing (left) and post-acidizing (right) injection/fall-off tests**

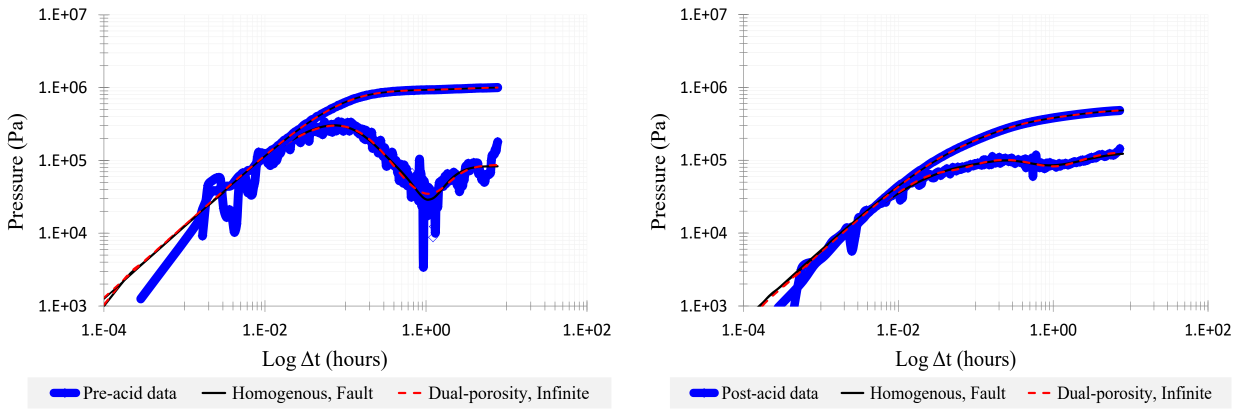



**Figure 13. Pressure derivative match of analytical models for pre-acidizing (left) and post-acidizing (right) fall-off datasets**

**Table 4. Model parameters obtained from analytical (SAPHIR™) and numerical (TOUGH2-PEST) PTA method**

| Parameter | Analytical (SAPHIR™) | | | | Numerical (TOUGH2-PEST) | | | |
|---|---|---|---|---|---|---|---|---|
| | Model | Pre-acid | Post-acid | Change | Model | Pre-acid | Post-acid | Change |
| k (mD) | Homogeneous, fault boundary | 37.15 | 37.20 | 0.13% | | | | |
| | Dual porosity, Infinite boundary | 30.61 | 28.30 | -8% | SLDP | 42.54 | 55.91 | 31% |
| | | | | | MLDP | 66.14 | 87.86 | 33% |
| Skin | Homogeneous, fault boundary | -1.56 | -4.80 | 208% | | | | |
| | Dual porosity, infinite boundary | -2.76 | -6.25 | 126% | SLDP | -1.54 | -3.38 | 119% |
| | | | | | MLDP | -0.45 | -1.92 | 323% |

### 4.4 Observation on the comparison of k and S between analytical and numerical method (field data)

Only the dual porosity infinite boundary of analytical model is available for comparison on the numerical models using single-layer dual porosity (SLDP), and multi-layer dual porosity (MLDP). The numerical model results for reservoir permeability (k) shows an overall increase of around 30%. In contrast, the analytical result shows almost no change in permeability. For the skin factor (S), the analytical method obtained the much lower skin factor compared to numerical, both for pre and post-acidizing dataset. This is different from the previous PTA result using simulated data which concludes that analytical model derived S is higher than the numerical model S due to the fact that analytical models do not take into account the non-isothermal effects which resembles a skin effect. However, both analytical and numerical result on S agrees that there is an improvement in the reservoir skin after acidizing. Based on the injectivity index plot (Figure 14), there is an increase of 50% in the injectivity index of well X after acidizing. This suggests a possible improvement in reservoir permeability (k) or skin (S) or both.

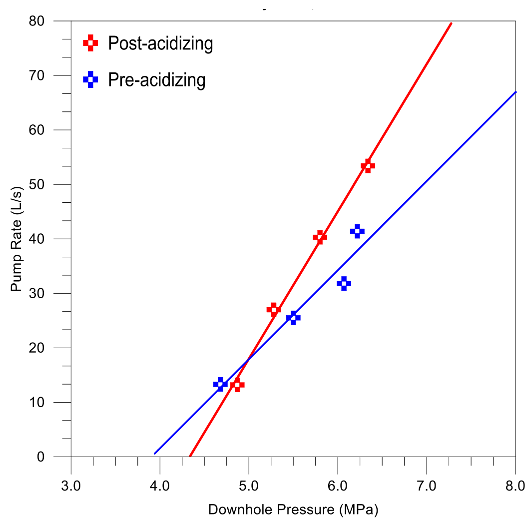



**Figure 14. Pre and post-acidizing injectivity index plot**

It is recognized that the numerical results are not considered reliable for this PTA due to the poor model fit of numerical models to the fall-off dataset both for pre and post-acidizing tests (Figure 12). Clearly, more work is needed with the data fitting approach or even in the numerical model setup itself before the numerical method presented in this paper can be used reliably for real world PTA problems.

## 5. CONCLUSION

The results of PTA on the simulated pressure transient data shows a good fit on both the analytical and numerical models. Derivative plot shows an infinite acting radial flow that resembles the type of reservoir it was modelled. All models are set to have an infinite boundary but the analytical model introduced a different boundary effect to match the simulated pressure transient data. This is attributed to the non-isothermal effect caused by the pressure change at zones of different temperatures that resembles a permeability boundary. Reservoir permeability (k) obtained from analytical method using SAPHIR$^{TM}$ are higher than the model value with a percent difference of 32% to 130%. The numerical method using TOUGH2-PEST was able to match the model k at different inversion (10x, 100x, 0.1x, and 0.01x) except for MLDP with a difference of 0% to 66%. Skin factor obtained from analytical method are higher than the model value with a difference of 7.5 to 10. This is attributed to the inability of analytical models to account for the non-isothermal reservoir condition which resembles a skin effect. Numerical method was able to match the model skin (S) at different inversion except for MLDP at 0.1x and 0.01x. Due to the large number of parameters of MLDP compared to other models, PEST needs an iteration of more than 20 to match the model k and S. The optimization for all models is set to 20 iterations to limit the simulation runs and for consistency. The PTA result shows that analytical method was not able to match the model k and S despite having a good model fit on the injection/fall-off dataset and pressure derivative dataset of the simulated pressure data. The difference in k and S are attributed to the non-isothermal effects during an injection/fall-off tests that analytical models cannot account. Since geothermal injection/fall-off tests will always have a non-isothermal condition due to the large difference between the reservoir and injectate temperature, it is recommended to use numerical PTA method to account for the non-isothermal effects.

The results of PTA on the actual field fall-off data shows good fit on the analytical model but poor on the numerical model. The field dataset is from the pre and post-acidizing injection/fall-off tests. The analytical model that is used to fit the actual field dataset is the homogenous reservoir with fault boundary and dual porosity reservoir with infinite boundary. Only the dual porosity with infinite boundary is subjected for comparison on the numerical models (SLDP and MLDP). Numerical results indicate an increase in the reservoir permeability (k) of around 30% but no change in permeability was obtained from the analytical result. Skin factor indicates an improvement in both analytical and numerical results. It is recognized that the numerical results are not considered reliable for this PTA due to the poor model fit of the numerical models to the fall-off dataset both for pre and post-acidizing tests. A number of improvements in the numerical model and numerical data fitting were identified and is the subject for future work.

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