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Numerical Pressure Transient Analysis of CO_2-Containing Geothermal Reservoirs during Draw-Down Buildup Testing

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ABSTRACT

Pressure transient testing in geothermal reservoirs involves a complex process of heat transfer and flow of multiphase fluids. Many geothermal reservoirs also contain considerable amounts of non-condensable gases (NCG), especially CO_2. Those conditions further complicate the analysis of geothermal well test data as the current pressure transient analysis (PTA) methods are mainly developed for single-phase flow and slightly compressible fluids. The purpose of this paper is to examine the suitability and accuracy of commonly used analytical PTA methods under multi-phase and multi-component conditions. Various numerical models were created to simulate geothermal reservoirs containing single-phase and two-phase mixture of water-CO_2 during draw-down build-up tests. The corresponding pressure responses from the numerical models were then analysed using analytical models to estimate reservoir properties. The results were investigated to assess the accuracy of the interpretation. The parameters used to analyse the pressure transient analysis were subjected to sensitivity analysis to identify their effect on the characteristic appearance of the pressure derivative plot shapes. The results obtained show that conventional analytical methods using pressure derivative can be reliably used to some extent in CO_2-containing reservoirs when no flashing takes place. However, several factors and variables that might mislead the interpretation of PTA data. The results are an attempt to lay the groundwork for future use of PTA in CO_2 rich geothermal fields.

1. INTRODUCTION

Accurate determination of geothermal reservoir parameters is important to formulate a strategy on how to exploit geothermal resource in the most economical way, and pressure transient testing is one of the essential tools for identifying these parameters. In general, geothermal PTA is a crucial step to evaluate well condition, determine the feed zones, and obtain reservoir parameters. Since the well test analysis methods were mainly developed for petroleum and groundwater applications where the reservoir is single phase, has relatively low temperatures and simple geological structures, applying the existing methods should be carried out with caution. This is because the geothermal reservoirs are non-isothermal, highly fractured, and the fluid properties are dependent on thermodynamic conditions; e.g. composition, pressure, temperature, and gas/liquid saturation (O'Sullivan et al. 2005), particularly during phase changes (flashing and condensation). Numerous studies in the past (Bourdet et al., 1983; Earlougher, 1977; Horne, Satman, & Grant, 1980; O'Sullivan, 1981; Ramey, 1988) have been conducted to address these issues, either by an analytical/semi-analytical method or numerically.

Most geothermal PTA still relies on analytical model software for analysing pressure transient testing that has been developed for petroleum application. This practice must be done with caution, especially for a far more complex geothermal reservoirs (two-phase or CO_2-containing geothermal reservoirs) as it might mislead the resultant interpretation. The limitation of an analytical model and the requirement for a numerical approach for complex systems has been recognised, and several studies have been conducted in the past using a numerical simulator such as TOUGH2 (O'Sullivan et al. 2005; McLean & Zarrouk, 2015a; McLean & Zarrouk 2015b, McLean et al. 2016, Kaya et al. 2019).

This work aims to investigate the accuracy of commonly used PTA methods for single-phase geothermal reservoirs with dissolved CO_2 reservoir. The effect of the variables on the PTA results and the characteristic appearance on the shapes of the derivative plots are also examined in this work. Base numerical models were set up by using TOUGH2 to represent geothermal reservoir conditions and to generate a series of drawdown/buildup test data, in the presence of various skin, boundary, phase and component conditions. The pressure responses were computed, and the model parameter's effect on the results was identified. The numerical model parameters were compared with the results of analytical model using SAPHIR™ software to investigate the accuracy of the analytical methods.

2. BACKGROUND

2.1 Previous Studies on Numerical PTA in Geothermal

The need for numerical modelling for PTA has been recognised for a long time. This is because the analytical models are based on diffusivity equation which does not match the geothermal datasets (Earlougher, 1977). There are many factors of geothermal reservoirs that violate the assumption of analytical models due to the high temperature and complexity of geothermal reservoirs. The geothermal reservoirs are non-isothermal and highly fractured, and the fluid properties are dependent on thermodynamic conditions; e.g. composition, pressure, temperature, and saturation (O'Sullivan et al., 2005), particularly during phase changes.

Horne et al., (1980) studied the effect of a two-phase boundary at a constant radial distance from a well caused by the flashing of hot water during production from or water injection into a two-phase reservoir. Garg and Pritchett (1984) developed an interpretation method for pressure transient data from two-phase geothermal reservoirs and employed the numerical result from a reservoir simulator to generate guidelines for calculating mobility-thickness product from pressure transient data. O'Sullivan (1987) used MULKOM

(TOUGH2) simulator to study the effect of fractured media compared to uniform porous media in pressure drawdown/build-up and injection test. In 2005, O'Sullivan et al. developed an Automated Well Test Analysis System (AWTAS) to simulate complex non-isothermal situations. McLean & Zarrouk (2015b) studied the application of pressure derivative method in geothermal and its common issues that might be encountered, such as downflow, slow valve closing, and two-stage pump shutdown. McLean and Zarrouk (2017) further developed a practical framework for numerical modelling of PTA datasets to investigate the effect of cold-water injection into the hot reservoir. Kaya et al. (2019) developed a radial numerical models, that create a layout for the present study, and investigated the suitability of commonly used PTA methods on single-phase CO2 containing geothermal reservoirs.

2.2 CO_2 Effect on Geothermal Well Test

CO_2 is one of the non-condensable gases (NCG) and some of the geothermal reservoirs contains significant amount of NCG. The presence of CO_2 can significantly affect the thermodynamic conditions and the results of a well test. Several studies have been conducted to investigate the effect of CO_2 presence during well tests. O'Sullivan *et al.* (1985) and Pritchett *et al*. (1981) studied the effect of CO_2 on fluid flow in geothermal reservoirs and the pressure response during well test. They showed that even with very small addition of CO_2 will results in large changes in the pressure drop during constant-rate drawdown tests.

During drawdown period, the presence of CO_2 will cause two effects: First, the degassing of CO_2 will make a rapid pressure drop at an early time. Secondly, the lower flowing enthalpy with CO_2 presence will cause a slower decline of the temperature and pressure at later times. It is found out that even if the reservoir properties are correctly identified as two-phase, a significant error in deducing *kh* from the slope of semilog pressure plot could still be made if the accurate information regarding of CO_2 content is not available.

2.3 Numerical and Analytical Model Software Utilisation

The AUTOUGH2 simulator was chosen in this work for numerical calculations of non-isothermal flows of multicomponent, multiphase fluids in porous media (Pruess et al., 1999; Yeh et al., 2012). The PyTOUGH scripting library was used for the automation of TOUGH2 simulation (Croucher, 2011). TIM, graphical tool (Yeh et al., 2013) was utilised for visualising the results from TOUGH2 simulations.

The analytical PTA software used was SAPHIR™, a commercial well test analysis software by KAPPA Engineering. SAPHIR™ can determine the reservoir's characteristics and properties by generating a derivative plot from pressure history data and match it with KAPPA's database (Houze et al., 2008).

3. NUMERICAL MODEL SET UP

3.1 Model Geometry

The geothermal reservoir is represented by a single layer (1D) radial model with a constant thickness of 600 m (Figure 1). The radial grid consists of 100 elements composed of 1 well block, 14 skin blocks, and 85 reservoir blocks. The central block representing the well has a radius of 0.1 m. A very fine grid structure in the region that is close to well block is implemented by using logarithmic radial block spacing. A large size of reservoir was considered, with the reservoir radius of 132 km to simulate the infinite-acting radial flow. As shown by McLean and Zarrouk (2017), the pressure response is insensitive to the grid block refinement in the skin zone and reservoir zone. Thus, in this study, the number of the grid blocks was kept constant.

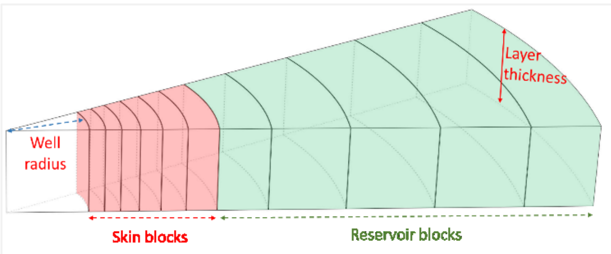


Figure 1: Schematic illustration of radial model geometry (after McLean and Zarrouk, 2017)

3.2 Model Parameter Set Up

The model parameters used are summarised in Table 1.

The effect of the CO_2 component was investigated by using the EOS2 module of TOUGH2. The primary variables input for EOS2 single-phase condition are as follow (Pruess et al., 1999):

- Pressure
- Temperature
- Partial pressure of CO_2

The initial reservoir temperature and pressure used was 250°C and 80 bar, respectively. The partial pressure of CO_2 is dependent on temperature and mass fraction of CO_2 in the fluid. According to Henry's Law, the partial pressure of NCG is proportional to the mole fraction of the gas in the aqueous phase:

$$P_{CO_2} = \frac{18}{44} K_h X_{CO_2} \tag{1}$$

Where Henry's Constant, K_h is calculated using a correlation from Battistelli et al., (1997), which extends the temperature range of Henry's constant correlation up to 350°C.

Table 1: Base model parameters

Well block properties	
Radius (r_w)	0.1 m
Porosity	0.9
Permeability	10000 mD
Rock compressibility	6E-8 Pa^{-1}
Skin zone properties	
Block number	14 blocks
Skin zone span (r_{skin})	3.875 m
Porosity value	0.1
Permeability	2 mD
Skin factor	14.63
Reservoir zone properties	
Radius	132 km
Block number	85 blocks
Porosity	0.1
Permeability	10 mD
Layer thickness	600 m

The linear model of relative permeability value was used for this study, with the $S_l = 0.3$ and $S_v = 0.05$

4. DRAWDOWN/BUILDUP TEST

4.1 Test Set-Up

The models were subjected to drawdown/buildup tests with a single drawdown rate of 25 kg/s for 48 hours, and a buildup period of 192 hours. The parameters used in the experiment were examined in the single-phase pure water model first (utilising *water, water with tracer Equation of State* / EOS1) to see if the model set up was correct before being tested in the more complex water-CO_2 model. Manual sensitivity analysis for the single-phase model was conducted for the parameters shown in Table 2. The vapour saturation results from the drawdown are monitored to ensure that the set of parameters used will not cause boiling. Manual sensitivity analysis for the water-CO_2 mixture model is conducted (by utilising the *water, CO_2 equation of state* module / EOS2) for each of the parameters given in Table 3, to see the effect of different parameter values on the pressure derivative and the analytical model's results obtained by utilising the SAPHIR™ software.

Table 2: Parameters tested for drawdown/buildup test (EOS1)

Parameter	Base Model Parameter	Value Range
Layer thickness (m)	600	250, 500, 600
Well radius (m)	0.1	0.1, 0.2, 0.3
Skin zone permeability (mD)	2 (skin factor value of +14.63)	2, 1, 22, 100, no skin zone

Table 3: Parameters tested for drawdown/buildup test (EOS2)

Parameter	Value Range
CO_2 content (%wt)	0%, 0.9%, 1%

4.2 Single-phase (EOS1) Model

4.2.1 Layer thickness

The base model used 600 m layer thickness for the radial model, but other thickness values were also tested (i.e. 250 m and 500 m). Since the models with small layer thickness have smaller volumes, they give more rapid pressure drop during drawdown, thus making them more susceptible to flashing. TOUGH2 simulation results demonstrate this fact. As can be seen in Figure 2, the smallest model thickness case (250 m) flashed during drawdown, resulting in a different pressure response profile when compared to the base model and 500 m thick model.

In the tables presented in this study, the following notation was used; the reservoir permeability "k (mD)", the difference in permeability between the actual TOUGH2 model input and the analytical model result "Δk (mD)". The skin factor (measure of damage or enhancement to the near wellbore rock face during drilling, operation or stimulation of the well) estimated using the pressure derivatives "Skin", and the difference in skin factor value between TOUGH2 model input and analytical model results "Δskin"

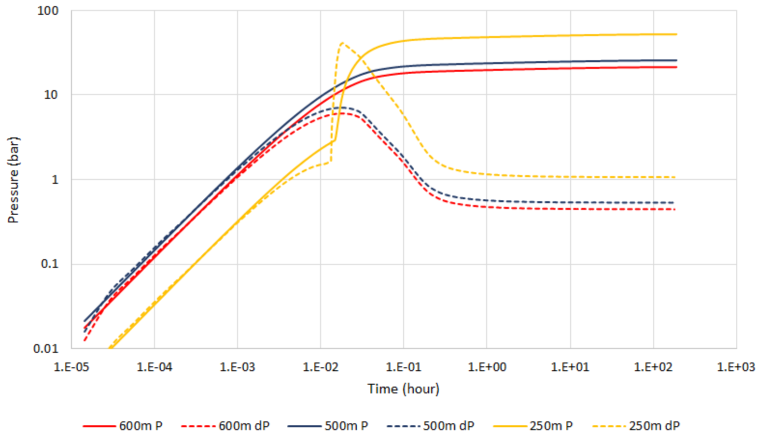


Figure 2: Effect of different layer thickness

Table 4: Reservoir properties estimated by SAPHIR's analytical model for different layer thickness

Thickness (m)	*k* result (mD)	Δ*k*	Skin value	Δskin value
600	10.1	0.1	15.5	0.87
500	10.1	0.1	15.4	0.77
250	Flashed	Flashed	Flashed	Flashed

Pressure derivative plot of the drawdown/buildup test (Figure 2) illustrates that the result is sensitive to the layer thickness. Table 4 shows a very close match to the parameter inputted to TOUGH2 (compared to the injection/falloff test that always overestimates the skin value (Kaya et al., (2019)). This is due to there being no significant temperature change during drawdown/buildup test, unlike the injection case where much cooler water is injected to the reservoir.

4.2.2 Wellbore radius

The base reference model uses a 0.1 m well radius, with the other values tested at 0.2 m and 0.3 m. Changing the well radius with a smaller value will shift the pressure derivative plot to the right, while still retaining the overall shape (Figure 3). This is expected, as increasing the well radius will increase the total well volume, which will increase wellbore storage. The reservoir properties estimated by SAPHIR's analytical model are summarized in Table 5. It can be seen that the reservoir permeability and skin values for the three models do not differ much.

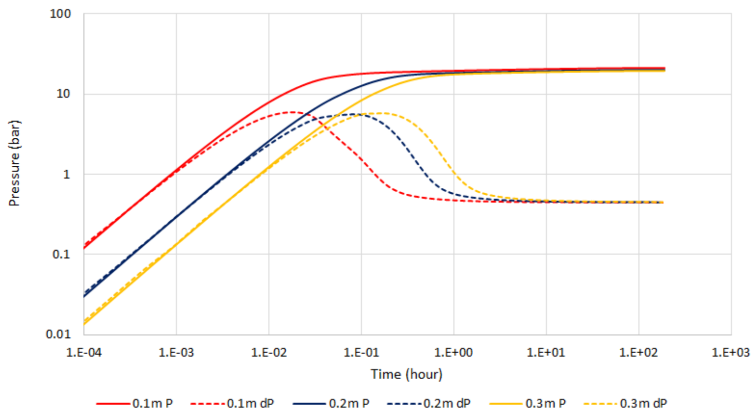


Figure 3: Effect of different wellbore radius

Table 5: Reservoir properties estimated by SAPHIR's analytical model for different wellbore radius

Wellbore radius (m)	*k* result (mD)	Δ*k*	Skin value	Δskin value
0.1	10.1	0.1	15.4	0.77
0.2	9.95	0.05	14.9	0.53
0.3	10.3	0.3	15.5	1.28

4.2.2 Skin factor value

The effect of changing skin zone conditions is simulated by changing the permeability value of the skin blocks. Figure 4 illustrates that changing the skin zone condition will affect the hump after the wellbore storage period on the pressure derivative plot with the higher the skin value (positive skin value) the bigger the hump. The overall unit slope of wellbore storage period and flat line of infinite acting flow is relatively unaffected by the changing skin condition. As the drawdown/buildup test for the single-phase reservoir does not involve a significant temperature change, the skin values are estimated reasonably well, and the difference between SAPHIR's analytical model and TOUGH2 input is very small for both the permeability and skin values (Table 6).

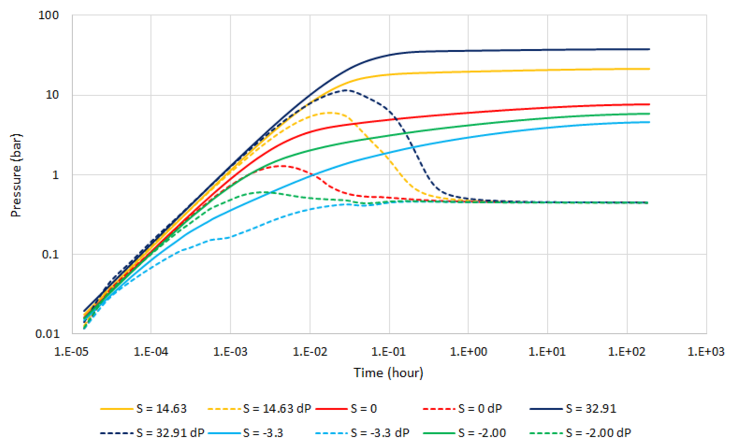


Figure 4: Effect of different skin factor value

Table 6: Reservoir properties estimated by SAPHIR's analytical model for different skin zone permeability

Skin permeability (mD)	Actual skin factor value	*k* result (mD)	Δ*k*	Skin value	Δskin value
2 (base model)	14.63	10.1	0.1	15.4	0.77
1	32.9	10.1	0.1	34.6	1.7
22	-2	9.95	0.05	-1.99	0.01
100	-3.3	9.95	0.05	-3.34	0.04
No skin block	0	9.95	0.05	0	0

The results for the single-phase EOS1 model shows that the model setup and the parameters used are adequate to be utilised in the model for the investigation of CO_2 effects. The well radius of 0.1 m was chosen as the well radius parameter, as it is the realistic value commonly used in the open hole part of a real geothermal well. The skin zone permeability value of 2 mD (skin factor value of 14.63) was used to represent the damaged zone inside the reservoir due to drilling using mud or mineral deposition. The well block compressibility used for the base model parameter in the CO_2 experiment was 6×10^{-8} Pa^{-1}, but for the real geothermal PTA dataset, this value should be calculated from the available data from the well test.

4.3 Water-CO_2 (EOS2) Model

The effect of dissolved CO_2 content on drawdown/buildup test was investigated as the presence of CO_2 inside geothermal fluid will alter its flashing point and increase the pressure drop rate during drawdown. Thus, the gas saturation of each experiment was carefully monitored to see if the flashing occurs during drawdown.

As the water at 250°C flashes at 39.759 bar, and the lowest pressure reached during drawdown test was 58.751 bar, the maximum allowable CO_2 partial pressure that will not cause the water to flash is 58.751 – 39.759 = 18.992 bar. That CO_2 partial pressure corresponds to the CO_2 content of ~0.98%wt of CO_2. Therefore, the range of parameter values chosen were 0%, 0.9%, and 1%. The 1% CO_2 model was included to see the effect of CO_2 flashing to pressure derivative plot.

The pressure derivative plot and the analytical model result are shown in Figure 5 and Table 7**,** respectively. The log-log plot of pressure derivative for models with dissolved CO_2 and no flashing give similar pressure response and indistinguishable pressure derivative curve (Figure 5). The similar results is also observed for reservoir properties estimated by SAPHIR's analytical model, as the permeability values given by SAPHIR are the same for both models but the skin factor value for 0.9% CO_2 is slightly higher due to the different fluid compressibility input to SAPHIR (Table 7**)**.

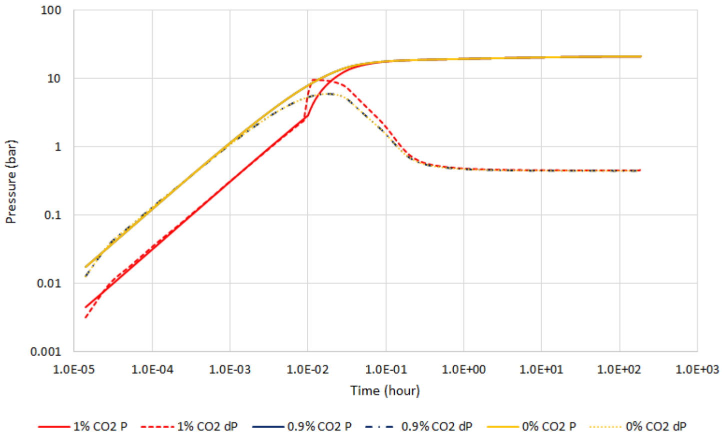


Figure 5: Effect of different CO_2 content

Table 7: Reservoir properties estimated by SAPHIR's analytical model for different CO_2 content

CO_2 content (% weight)	CO_2 partial pressure	*k* result (mD)	Δ*k*	Skin value	Δskin value
0%	0 bar	9.95	0.05	15.1	0.77
0.9%	18.271 bar	9.95	0.05	17.8	3.17
1% (flashed)	20.301 bar	flashed	flashed	flashed	flashed

4.4 CO_2 Release during Drawdown

A numerical experiment was conducted to investigates the pressure response of single-phase models containing CO_2 that underwent drawdown until the release of CO_2. Table 8 summarises the model CO_2 content and at what pressure the CO_2 will be released. Figure 6 shows the pressure history plot of the three models. The 1% CO_2 model pressure history is indistinguishable with the EOS1 model, but the 1.5% and 1.9% model the pressure dropped further during drawdown, and on 1.9% CO_2 model even showed fluctuation during buildup.

Table 8: Condition of models underwent drawdown until CO_2 released

CO_2 content (by weight)	Lowest pressure reached during drawdown	Boiling point pressure of water @ 250°C	Partial pressure of CO_2	CO_2 release pressure
1%	58.751 bar	39.759 bar	20.301 bar	60.061 bar
1.5%	57.810 bar	39.759 bar	30.452 bar	70.211 bar
1.9%	57.830 bar	39.759 bar	38.753 bar	78.331 bar

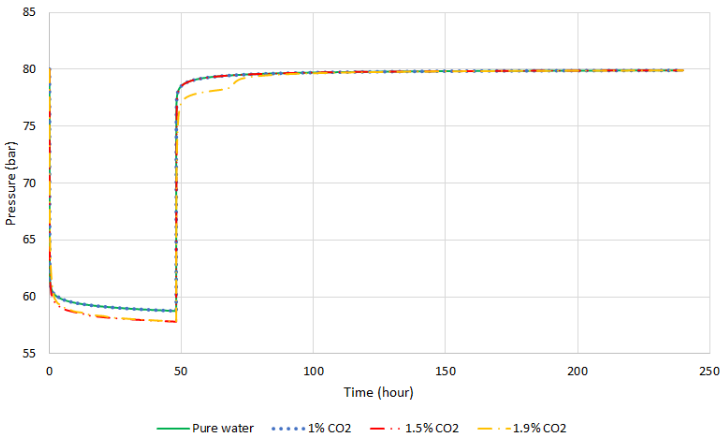


Figure 6: Pressure history plot of drawdown/buildup test for different CO_2 content

Figure 7 illustrates the log-log pressure and pressure derivative plot results for the models. Even though the shape and profile of the pressure derivative plots are different, the 1% and 1.5% CO_2 model derivative plot still converge on the flat line of infinite-acting flow region. The 1.9% CO_2 model, however, still shows fluctuation during infinite-acting flow region. As SAPHIR™ cannot generate exact matches for the pressure derivative plots, the infinite-acting flow region on the later time of buildup can still be considered for match purposes to get a rough estimation of parameters. Semilog approach was also performed to see whether this approach can give realistic estimation for the reservoir properties for these cases. Table 9 summarises the reservoir properties estimated by the pressure derivative and semilog method.

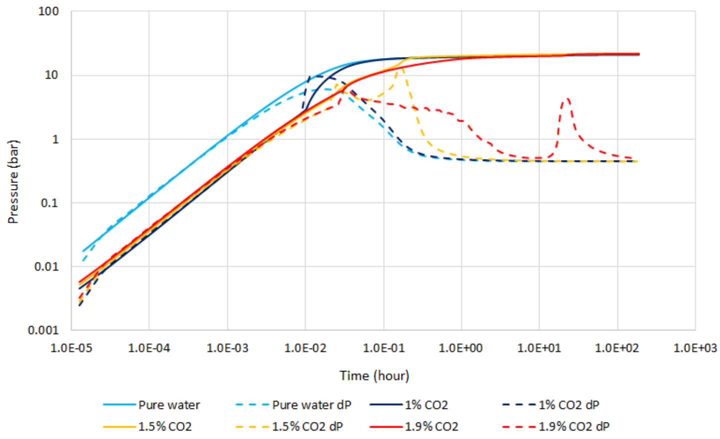


Figure 7: Effect of different CO_2 content that underwent drawdown until the CO_2 released (modified from Kaya et al., 2019)

Table 9: Reservoir properties estimated by SAPHIR's analytical model in the CO_2 released during drawdown

Model	Pressure derivative match		Horner plot - buildup		Semilog plot - drawdown	
	k (mD)	skin	*k* (mD)	skin	*k* (mD)	skin
1% CO_2	9.95	14.7	9.83	14.9	10.1	15
1.5% CO_2	9.95	16.2	10	16.3	10.4	17.3
1.9% CO_2	8.71	14.6	8.11	11.7	8.43	13.9

The semilog plot results for drawdown are presented in Figure 8. As the CO_2 is released from the geothermal fluid during drawdown, the pressure derivative on semilog plot shows some fluctuation, and the fluctuation becomes more apparent in 1.9% CO_2 model, rendering the flat line unobservable. The highlighted region marks when the CO_2 started to be released due to pressure drop.

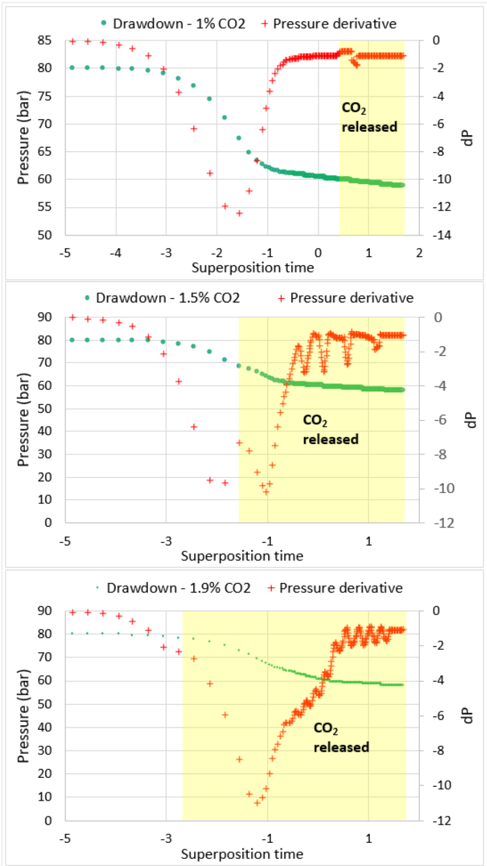


Figure 8: Semilog plot for 1%, 1.5%, and 1.9% CO_2 model drawdown

4.4 Higher Production Flowrate during Drawdown

An experiment was set up to observe the effect of CO_2 release when the reservoir pressure drop below boiling point pressure at reservoir temperature during drawdown. The model parameters are similar to previous parameters shown in Section 4.1, apart from the production rate and CO_2 content changed to 60 kg/s and 1.9%wt, respectively. The lowest pressure reached during drawdown was 22.55 bar, which is way lower than vapour saturation of pure water at 250°C. Figure 9 shows the pressure derivative plot of TOUGH2 simulation and matching attempt by using SAPHIR's analytical model. The analytical model can only match the early unit slope and some parts of the latter flat line of infinite-acting flow region. However, this results in close estimations of reservoir permeability and skin value between SAPHIR model matching and actual value inputted to TOUGH2 as shown in Table 10.

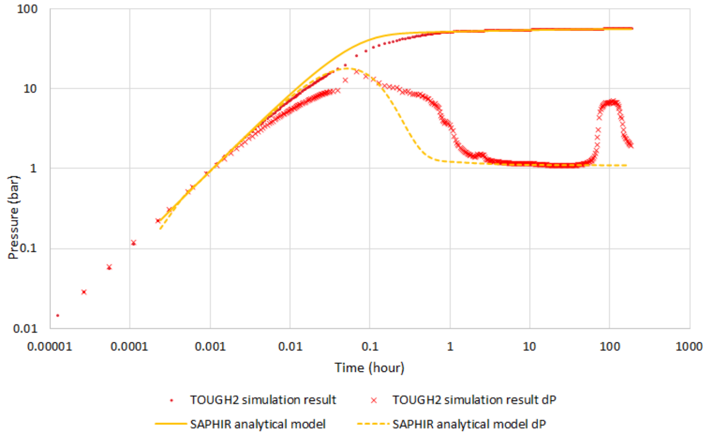


Figure 9: Pressure derivative plot result and SAPHIR analytical model matching

Table 10: Reservoir properties estimated by SAPHIR's analytical model in the CO_2 released and water flashed during drawdown

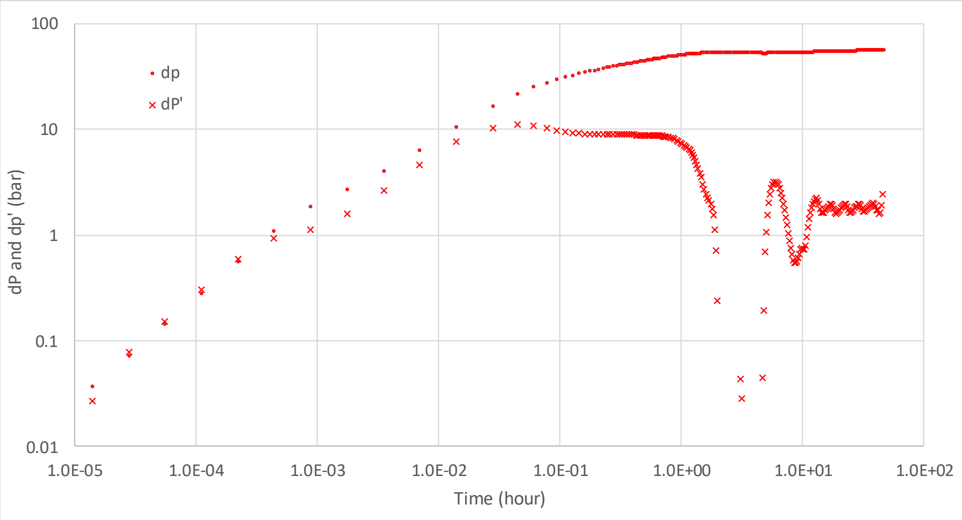
Pressure derivative match (buildup)		Horner plot – buildup (result from SAPHIR)		Semilog plot – drawdown (result from SAPHIR)	
k **(mD)**	**skin**	***k*** **(mD)**	**skin**	***k*** **(mD)**	**skin**
9.69	17	9.42	16.2	6.03	7.42

Table 10 shows that the reservoir properties estimated by using buildup data gives a close result to actual value inputted to TOUGH2, while the result from drawdown semilog plot underestimates both the reservoir permeability and skin factor value. This is probably due to the presence of high amount of gas phase in the mixture during drawdown. On the other hand, during buildup the mixture returns into compressed water, thus the result from buildup semilog gives a closer value.

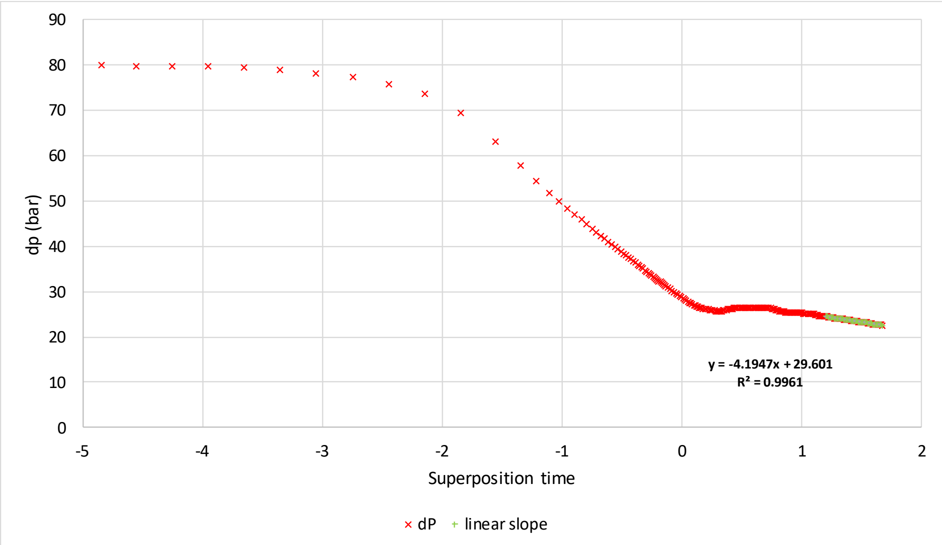
To investigate this, a manual calculation using MDH plot for drawdown was carried out. The reservoir permeability was then calculated with regards to two-phase properties and CO_2 presence based on the total (or flowing) kinematic viscosity approach by O'Sullivan et al. (1985). The semilog plot and the calculation results are shown in Figure 10 and Table 11**,** respectively. It is interesting to note that as the CO_2 is released and water flashed during drawdown, the pressure derivative never stabilises to reach the flat line.

Table 11: Reservoir permeability calculation using MDH plot calculation in the CO_2 released and water flashed during drawdown

Reservoir permeability (mD)	
Using two-phase properties	**SAPHIR**
6.03	9.86



(a)



(b)

Figure 10: a) log-log plot b) MDH plot for the drawdown test

5. CONCLUSIONS

This work investigated the reliability of the results of commonly used PTA for drawdown/buildup tests under multiphase and multicomponent conditions for geothermal reservoir with dissolved CO_2. The effect of several model parameters on the PTA analysis and characteristic appearance of the derivative plots were also assessed. The following findings were observed:

Layer Thickness

The pressure derivative is sensitive to the change of layer thickness as the change in layer thickness will shift the pressure derivative curve up and down. There is no significant difference in reservoir properties estimated by SAPHIR's analytical result between models tested. However, for the model with smaller layer thickness is susceptible to flashing during drawdown due to its volume.

Wellbore radius

Changing the well radius with a smaller value will shift the pressure derivative plot to the right, while still retaining the overall shape. However, for all of the tested well radius values give a close match between TOUGH2 input parameter and SAPHIR analytical model result.

Skin factor value

The higher skin factor value (positive skin) will create bigger hump after the unit slope, while negative skin value (higher permeability value in skin zone blocks) show smaller hump. The overall unit slope of wellbore storage period and flat line of infinite acting flow is relatively unaffected by the changing skin condition.

CO_2 content

The presence of CO_2 in the reservoir does not affect the pressure response during the pressure transient test, as long as the CO_2 is dissolved inside geothermal fluid. Thus, the model with dissolved CO_2 and no flashing gives similar pressure response and indistinguishable pressure derivative curve to the pure water model. The reservoir properties (permeability and skin factor values) estimated by analytical model are similar for the pure water models and the models with dissolved CO_2.

If the pressure during drawdown is lower than the sum of CO_2 partial pressure and water boiling point pressure, the CO_2 will be released from the fluid and alter the pressure response. The pressure derivative plot is not recognizable by SAPHIR, but as the early and late time of buildup still shows unit slope and flat line, the reservoir properties can still be estimated. The attempt to calculate the reservoir properties with semilog plot also gave a close estimation of actual the value inputted to model.

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