INVESTIGATION OF PRESSURE TRANSIENT ANALYSIS METHODS FOR CO_2-RICH GEOTHERMAL RESERVOIRS

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ABSTRACT

Many geothermal reservoirs contain considerable amounts of non-condensable gases (NCG), particularly CO_2. Thus, the analysis of geothermal well test is often complicated by multi-phase and multi-component effects as pressure transient analysis methods are mainly developed for single-phase flow and slightly compressible fluids.

This work aims to investigate the suitability of commonly used pressure transient analysis methods under various phase and component conditions. A series of numerical models were constructed for a geothermal reservoir containing a mixture of water and CO_2 incorporating the production/injection record and the corresponding pressure response. The pressure response of the numerical models was analysed using commercial software to generate the pressure derivative plot and to estimate the reservoir properties, and explore the accuracy of the interpretations. The parameters used to analyse the pressure transient tests were also subjected to manual sensitivity analysis to identify their effect on the characteristic appearance of the pressure derivative plot shapes for realistic interpretations of the reservoir characteristics.

The results obtained show that conventional analytical methods using the pressure derivative can be reliably used to some extent in CO_2-containing reservoirs. However under different multiphase conditions, well test derived properties should be interpreted with great caution.

1. INTRODUCTION

Pressure transient testing is one of the essential tools for identifying the in situ properties of the reservoir. A well-executed test combined with the utilisation of modern pressure transient analysis (PTA) techniques can help in evaluating the field potential during the exploration stage and monitor the well and reservoir performance and in understanding the causes of performance deviation in the development (production) stage.

Pressure transient testing in geothermal reservoirs involves a complex process of heat transfer and flow of multicomponent fluid mixtures in the reservoir, including boiling, condensation and dissolution. However, conventional analytical well test analysis methods developed for petroleum and groundwater applications do not account for some of these phenomena. Since there is a lack of PTA methodology for analysing non-isothermal, multi-phase, multi-component systems, geothermal well testing analysis still relies on conventional analytical methods (Grant, 2011; McLean & Zarrouk, 2015). Applying the existing methods should be carried out with caution for complex systems such as two-phase or CO_2-containing geothermal reservoirs as it can result in misleading interpretations.

Numerical simulators such as TOUGH2 can model these physical processes, including the phase transitions from a single-phase (vapour or liquid) into a two-phase mixture and also the presence of non-condensable gases (NCG) such as CO_2. Therefore the integration of numerical models with PTA techniques allows us to assess the accuracy of these methods under certain conditions and evaluate their applicability and limitations.

The purpose of this work is to investigate the suitability of commonly used PTA methods under multiphase and multicomponent conditions. Then, investigate the effect of different variables on the PTA results and the characteristic appearance of the shape of the derivative plot. Several numerical models were constructed of a geothermal reservoir containing a mixture of water and CO_2 incorporating the production/injection record and the corresponding pressure response. The pressure response of the numerical model was analysed by SAPHIR™, to generate the pressure derivative plot, estimate the reservoir properties, and explore the accuracy of the interpretations. The parameters used to analyse the pressure transient tests were also subjected to manual sensitivity analysis to identify their effect on the characteristic appearance of the derivative plot for realistic interpretations of the reservoir characteristic.

2. BACKGROUND

2.1 Previous studies on PTA in geothermal

The analytical models for PTA are mainly developed for petroleum and groundwater applications where the reservoir has a low temperature and simple geological structure. However, 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 the two-phase boundary 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. O'Sullivan et al. (2005) developed an Automated Well Test Analysis System (AWTAS) to simulate complex non-isothermal situations. McLean and Zarrouk (2017) developed a practical framework for numerical modelling of PTA datasets to investigate the effect of cold water injection into hot reservoir.

2.2 Effects of CO_2 on geothermal well test

Geothermal reservoirs contain naturally occurring non-condensable gasses (NCG) which are mainly derived from host rock of the geothermal system. The most dominant gas commonly found in geothermal fluids is CO_2, accounting for ~90% of the total NCG by volume (Bertani & Thain, 2002). The presence of CO_2 may considerably affect the production behaviour of a geothermal well. Even the very small addition of CO_2 can result in substantial changes in the pressure drop during constant rate drawdown test (O'Sullivan et al., 1985; Pritchett et al., 1981). For the most common types of geothermal well tests (i.e. drawdown/build-up tests, injection/fall-off tests) in which expansion and compression of NCG can occur, analytical models may not perform well.

2.3 Numerical and Analytical Model Software Utilised

This study uses the AUTOUGH2 simulator 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 setup and simulation (Wellmann et al., 2012). The TIM graphical tool was utilised for assisting in visualising the results from TOUGH2 simulations (Yeh et al., 2013).

The analytical PTA software used was SAPHIR™, which can generate a pressure derivative plot from pressure history data to estimate the reservoir's characteristics and properties (Houze et al., 2008).

3. NUMERICAL MODEL SET UP

3.1 Model Geometry

The reservoir is represented as a single layer with a thickness of 600 m and uses a radially symmetric grid structure (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. The width of the remaining elements increases by a constant factor of 1.1. To simulate the infinite-acting flow, the reservoir size was made very large, with the reservoir radius of 132 km. As shown by McLean and Zarrouk (2017), the pressure response is insensitive to the grid block refinement in the skin zone and reservoir zone, and in this study, the number of the grid blocks was kept constant.

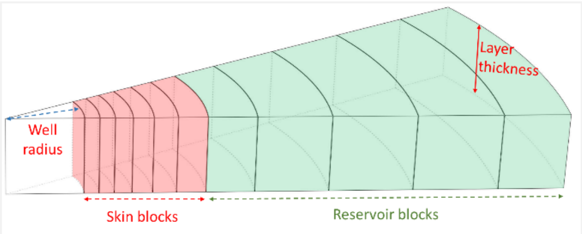

Figure 1: Schematic illustration of radial model geometry (after McLean and Zarrouk, 2017)

3.2. Model Parameter Set Up

The model parameters used are summarised in Table 1 below:

Table 1: Model parameters

Well block properties	
Radius (r_w)	0.1 m
Porosity	0.9
Permeability	10000 mD
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 relative permeability functions were used, with the S_l = 0.3 and S_v = 0.05.

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

- Single-phase conditions:
Pressure, temperature, partial pressure of CO_2
- Two-phase conditions:
Gas phase pressure, gas saturation, partial pressure 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:

$$P_{CO_2} = \frac{18}{44} K_h X_{CO_2} \quad (1)$$

Where the 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.

4. INJECTION/FALLOFF TEST

4.1. Test setup

The models were subjected to an injection/falloff test with a single injection rate (25 kg/s) for 24 hours, and a falloff period of 96 hours. The parameters used in the experiment were used 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. Manual sensitivity analysis for the water-CO_2 mixture model is conducted for each of the parameters given in Table 3.

Table 2. Parameters for injection/falloff 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
Well block presence	With well block	With well block, no well block
Well block compressibility (1/Pa)	6×10^{-8}	1×10^{-4}, 1×10^{-20} (extreme) 3×10^{-8}, 6×10^{-8}, 9×10^{-8}
Skin zone permeability(mD)	2	1, 2, 22, 100, No skin block
Injectate temperature	134 °C	50°C, 134°C, 250°C

Table 3: Parameters for injection/falloff test (EOS2).

Parameter	Base model parameter	Range tested
CO_2 content (% wt)	1.98%	0%, 1%, 1.98%, 2%
Injectate temperature	134°C	50°C, 134°C. 250°C
Well block compressibility (1/Pa)	6×10^{-8}	3×10^{-8}, 6×10^{-8}, 9×10^{-8}
Skin blocks permeability (mD)	2	1, 2, 10, 22, 100

The analytical model in SAPHIR™ can only specify one fluid property, and several previous studies concluded that it is appropriate to use thermophysical properties of water at reservoir temperature, even though in the real situation, the water temperature during reinjection of cold water varies (McLean & Zarrouk, 2017; O'Sullivan & McKibbin, 1989). However, as the water compressibility varies with the change in CO_2 content, a manual sensitivity analysis is conducted to see the effect of different fluid compressibility values on the reservoir properties estimations. The compressibility of geothermal fluid containing CO_2 was calculated using the following equation (Kaya et al., 2005):

$$C_C = \frac{44}{18}\frac{\rho_W}{\rho_S}\frac{P_S}{K_h^2 X_{CO_2}} \tag{2}$$

Where C_C is the fluid compressibility (1/Pa) of the fluid containing the CO_2, ρ_W and ρ_S is density (kg/m^3) of liquid water and density of water vapour, P_S is the boiling pressure (Pa) of steam, K_h is the Henry's constant, and X_{CO_2} is the mass fraction of CO_2.

4.2. Results for single-phase EOS1 model

To obtain realistic predictions for practical pressure transient analysis problems that involve multicomponent, multidimensional flow effects over a broad range of space and time scales, numerical models were set up, and the various aspects of model design and reservoir parameters were investigated. By understanding the sensitivity of model results to various reservoir parameters and the model geometry used to simulate pressure transient tests, this section attempts to provide the best alternative for model grid structure and model parameters to obtain a generic model of a reservoir that is suitable for the investigation of pressure transient analysis.

Manual sensitivity analysis is individually performed for each model parameter by using the pressure derivative plot and SAPHIR's analytical model results for the single-phase model. Results are shown for sensitivity of results to layer thickness (Figure 2 & Table 4), well radius (Figure 3 & Table 5), well block compressibility value (Figure 4 & Table 6), skin zone permeability value (Figure 5 & Table 7) and injectate temperature (Figure 6 &
Table 8). The sensitivity analysis for the pressure derivative plots shows a similar trend to that observed by McLean and Zarrouk (2017) from their experiments, while the analytical model results give a close match to reservoir permeability. The skin factor, however, is overestimated due to the base model's injectate temperature of 134°C. In the tables; "***k* (mD)**" represents the reservoir permeability; "**Δ*k* (mD)**" is the difference in permeability value between TOUGH2 model input and the analytical model result; "**Skin**" is the skin factor estimated by SAPHIR™; and "**Δskin**" is the difference in skin factor value between TOUGH2 model input (calculated as 14.63 for the base model parameters) and analytical model results.

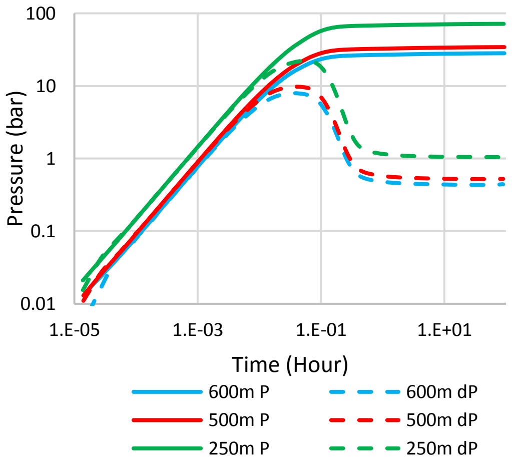

Figure 2. Effect of different layer thickness.

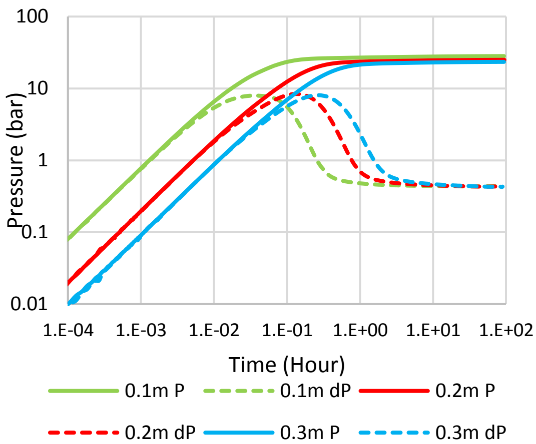

Figure 3. Effect of different well radius.

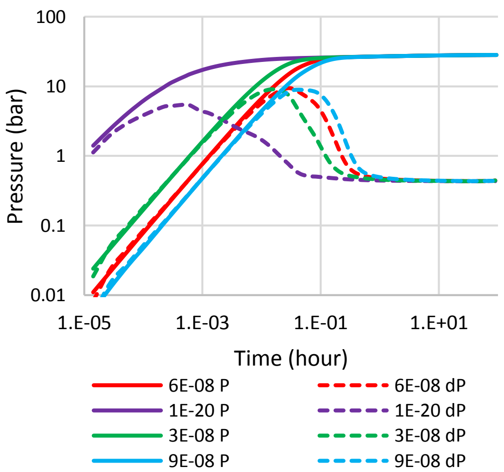

Figure 4. Effect of different well block compressibility on the pressure derivative.

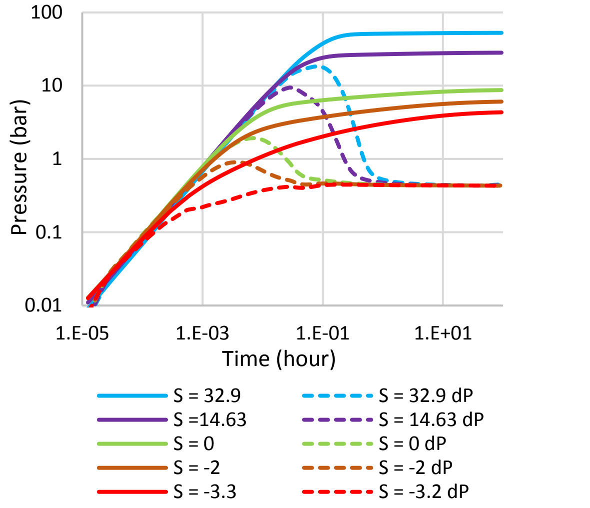

Figure 5. Effect of different skin factors on the shape of the pressure derivative.

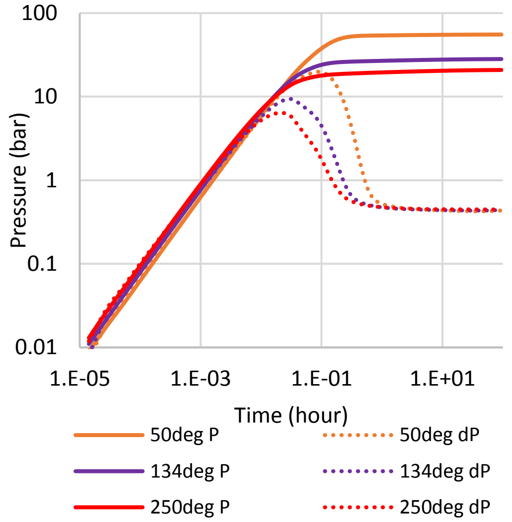

Figure 6. Effect of different injectate temperature.

Table 4. Different layer thickness

Thickness (m)	*k* (mD)	Δ*k* (mD)	Skin	Δskin
600	10	0	23.6	8.97
500	10.5	0.5	25.5	10.87
250	10.2	0.2	26.2	11.57

Table 5. Different well radius

Radius (m)	*k* (mD)	Δ*k* (mD)	Skin	Δskin
0.1	10	0	23.6	8.97
0.2	10	0	21	6.64
0.3	10.5	0.5	20.7	6.49

Table 6. Different well block compressibility

Compressibility (1/Pa)	*k* (mD)	Δ*k* (mD)	Skin	Δskin
3E-08	9.96	0.04	23.4	8.77
6E-08	10	0	23.6	8.97
9E-08	10.4	0.4	24.8	10.17

Table 7. Different skin factor

Actual skin factor value	Analytical model result			
	k result (mD)	Δ*k* (mD)	Skin factor	Δskin
32.9	9.95	0.05	50.7	17.8
14.63	10	0	23.6	8.97
0	10.5	0.5	2.14	2.14
-2.00	10.4	0.4	-1.05	0.95
-3.29	10.4	0.4	-3.09	0.21

Table 8. Different injectate temperature

Injectate temperature	*k* result (mD)	Δ*k* (mD)	Skin factor	Δskin
50°C	10.4	0.4	58.8	44.17
134°C	9.96	0.06	25.8	11.17
250°C	9.95	0.05	17.5	2.87

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 due to 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. The base model injectate temperature used was 134°C, as it is a typical temperature of separated geothermal water (Kaya et al., 2018).

4.3. Water-CO_2 (EOS2) model

The partial pressure of CO_2 can be calculated using Equation (1), and the maximum CO_2 content that will keep the CO_2 dissolved inside geothermal fluid under reservoir conditions can be estimated. For the reservoir pressure of 80 bar and a temperature of 250°C, the maximum CO_2 content is ~1.98% by weight. Beyond 1.98%, the CO_2 will be released as free CO_2 inside the reservoir resulting in two-phase effects. Therefore, 1.98%wt of CO_2 was used as the base model parameter. The 2% CO_2 model was included to see the effect of free CO_2 inside the reservoir on the pressure response. The pressure derivative plot and the reservoir properties estimated by the SAPHIR™ analytical model are given in Figure 7 and Table 9.

Pressure derivative plot shows that models with dissolved CO_2 give similar pressure responses and indistinguishable pressure derivative curves (Figure 7) for various CO_2 %wt content. However, for the model with free CO_2, the pressure derivative curve initially follows the same unit slope of wellbore storage, then after the hump, the pressure derivative decreases and reaches a flat line of infinite acting flow at a much lower pressure derivative value compared to the dissolved CO_2 model. The pressure history plot of the 2% CO_2 model reveals that during the very early time of injection, the reservoir pressure decreases instead of increasing due to the free CO_2 compressed into the reservoir fluid (Figure 8).

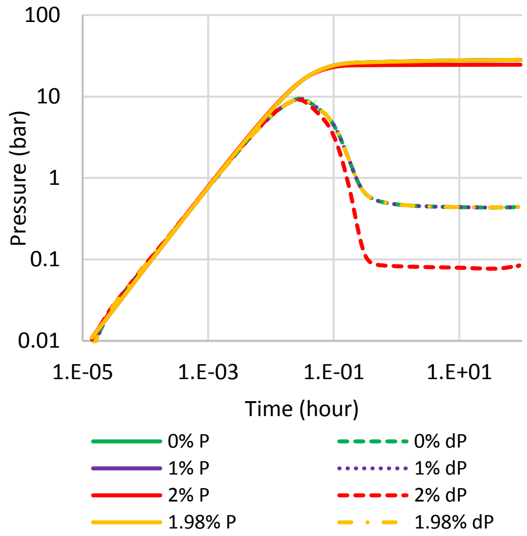

Figure 7: Pressure derivative plot showing the effect of varying CO_2 content.

Table 9: SAPHIR's analytical model results: effect of varying CO_2 content.

CO_2 content (%wt)	CO_2 partial pressure (bar)	*k* result (mD)	Δ*k* (mD)	Skin value	Δskin value
0%	0	9.96	0.04	23.4	8.77
1%	20.301	9.96	0.04	25.8	11.17
1.98%	40.019	9.96	0.04	25.4	10.77
2% (free CO_2)	40.061	No match	No match	No match	No match

Even though models with dissolved CO_2 show indistinguishable pressure derivative plots, SAPHIR™ estimates different skin factor values for each model. This is due to the difference in the fluid compressibility values inputted to SAPHIR, as the fluid compressibility will vary depending on the CO_2 content. SAPHIR™ could not generate any match for the 2% CO_2 model, thus the reservoir properties cannot be estimated.

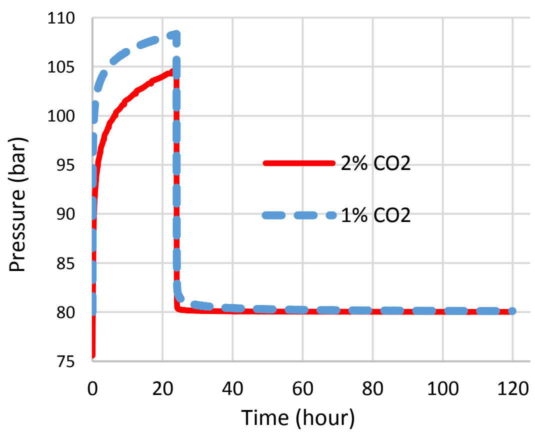

Figure 8: Pressure history plot: comparison of model with free CO_2 (2%) and dissolved CO_2 (1%).

4.3.1. Semilog calculation for the model initially having free CO_2

The 2% CO_2 model gave a pressure derivative plot result that cannot be matched by the SAPHIR analytical model. To further investigate this peculiar result, a semilog analysis of the numerical model results during the pressure falloff period was carried out by using the Horner plot. The Horner plot and the reservoir properties result are given in Figure 9 and Table 10 respectively. The semilog calculation gives a significantly exaggerated reservoir permeability and skin factor.

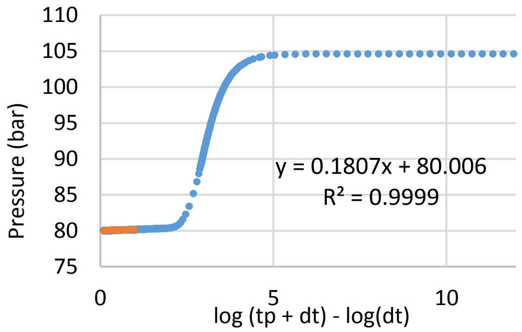

Figure 9: Horner plot for 2% CO_2 model (pressure falloff period).

Table 10: Reservoir properties estimated by a semilog Horner plot.

Reservoir permeability	Skin factor
137 mD	150

4.4. Injectate temperature

McLean and Zarrouk (2017) found that injecting water with a temperature lower than reservoir temperature will result in a larger derivative hump that can be misinterpreted as a high skin factor. McLean and Zarrouk's experiment was repeated using the 1.98% CO_2 model to see if the same effect is also observed for the single-phase case with the dissolved CO_2. Figure 10 shows the pressure derivative plot for models with different injectate temperatures. A similar result as with McLean and Zarrouk's experiment was observed: the larger temperature difference results in greater hump, while the late time is unaffected. This result is consistent with the result in Figure 7, where the models with dissolved CO_2 (no free CO_2) show exactly the same pressure response as the single-phase model.

Table 11 shows the reservoir properties estimated by SAPHIR's analytical model. As expected, the result for 50°C model has its skin factor value significantly overestimated, while the 250°C model (same temperature between injectate and reservoir) only has a minor difference in its skin factor value from the original value assigned to the model.

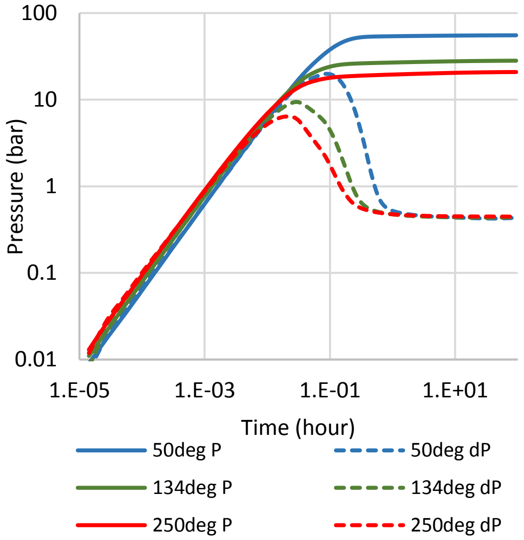

Figure 10. Pressure derivative plot: effect of varying injectate temperature.

Table 11. SAPHIR's analytical model result: effect of varying injectate temperature.

Injectate temperature	*k* result (mD)	Δ*k* (mD)	Skin factor	Δ skin
50°C	10.4	0.4	58.8	44.17
134°C	9.96	0.06	25.8	11.17
250°C	9.95	0.05	17.5	2.87

4.4.1. Effect of changes in injectate temperature to the presence of free CO_2

As the semilog calculation for the model with free CO_2 gives significantly overestimated reservoir properties, an experiment was carried out to investigate whether the skin factor exaggeration is caused by the presence of CO_2 only or the temperature difference between hot reservoir and injectate. The experiment was carried out by varying injectate temperature of models with 2% CO_2; one was injected with 250°C water, and the other was injected with 134°C water. Figure 11 shows the pressure derivative plot with the 0% CO_2 model results also shown for comparison.

As can be seen from Figure 11, injecting cooler water increases the size of derivative hump after the wellbore storage period, however, in the models with 2% CO_2, the flat infinite-acting region are still shifted down further compared to the 0% CO_2 model. Semilog calculation with the Horner plot was performed to estimate the reservoir properties for the 2% CO_2 model with an injection temperature of 250°C. Results show that even if the reinjection fluid temperature is equal to the reservoir temperature, the reservoir permeability and skin factor values are overestimated when free CO_2 phase is present in the reservoir (Table 12).

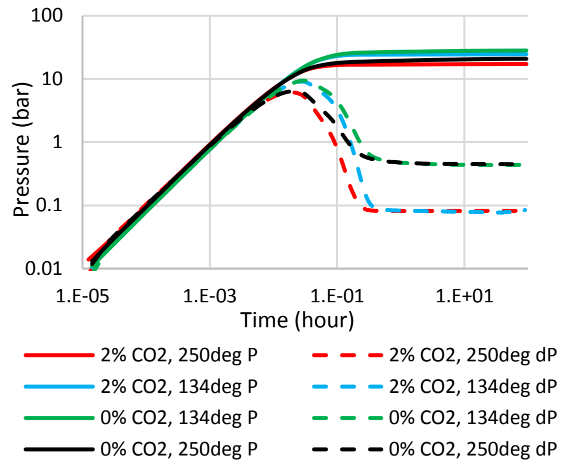

Figure 11. Pressure derivative plot: effect of varying injectate temperature on model with free CO_2.

Table 12. Reservoir properties estimated by semilog calculation.

Model	*k* (mD)	Skin factor
134°C Injectate	137	150
250°C Injectate	54.4	95.9

4.5. Well block compressibility value

As the wellbore was represented with a highly porous and permeable block in the TOUGH2 model, it is important to assign a large enough compressibility value in the well block to represent the movement of the fluid level in the wellbore during reinjection. McLean and Zarrouk (2017) found that the pressure response for single-phase pure water model is sensitive to the well block compressibility value assigned, and an experiment was carried out to see the effect of different well block compressibility values on our models with dissolved CO_2. The well block compressibility values tried are shown in Table 3. Models with extremely small (10^{-20} Pa^{-1}) and extremely large ($10^{-4}Pa^{-1}$) value of well block compressibility were also tested to see the effect on the pressure response. The pressure derivative plot presented in Figure 12 shows that the model results are sensitive to the well compressibility, and the higher compressibility shifts the derivative plot to the right. Assigning an extremely small well block compressibility shifts the pressure derivative plot to the left and made the unit slope characteristic of wellbore storage period unrecognisable (Figure 12). Assigning extremely large well block compressibility caused an atypical pressure response, possibly due to numerical instability. The analytical models gave accurate results since the estimated permeability values are similar to the TOUGH2 model input permeability (Table 13). The difference in the skin factor is due to the cooler injectate temperature.

Table 13. SAPHIR's analytical model result: effect of varying well block compressibility.

Well Compressibility (Pa^{-1})	*k* (mD)	Δ*k* (mD)	Skin	Δskin
3×10^{-8}	9.96	0.04	25.4	10.77
6×10^{-8}	9.96	0.04	25.8	11.17
9×10^{-8}	10.4	0.4	26.9	12.27

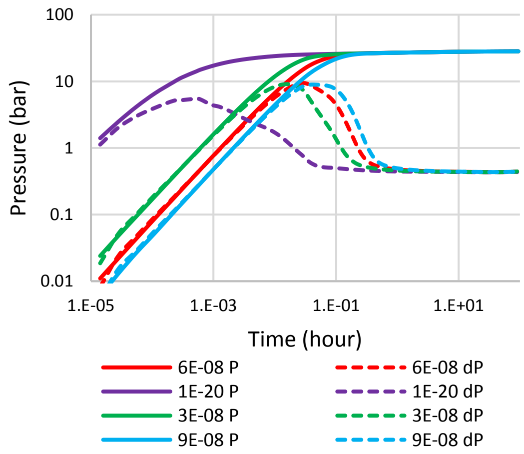

Figure 12. Pressure derivative plot: effect of varying well block compressibility value.

4.6. Skin factor

To see the effect of different skin factor, particularly the negative skin effect to the pressure response of the models containing CO_2, an experiment was carried out by changing the permeability of the skin blocks as shown in Table 14. The pressure derivative plots and the reservoir properties estimated by SAPHIR are shown in Figure 13 and Table 15 respectively.

Table 14. Model skin block parameters.

Skin blocks permeability (mD)	Reservoir blocks permeability (mD)	Skin factor
No skin block	10	0
1	10	32.91
2	10	14.63
22	10	-2.00
100	10	-3.29

Table 15. SAPHIR's analytical model result: effect of varying skin block permeability.

Actual skin factor	SAPHIR's result			
	k result (mD)	Δ*k* (mD)	Skin factor	Δskin
32.9	9.95	0.05	52.8	19.88
14.63	9.96	0.04	25.4	10.77
0	10.4	0.4	4.9	4.9
-2.00	10.4	0.4	0.996	2.99
-3.29	10.4	0.4	-1.04	2.25

Changing the permeability of the skin blocks will affect the hump of the derivative after the wellbore storage period; the higher the skin value (positive skin value), the bigger the hump. The analytical model overestimates the skin factor due to the effect of injecting cooler water.

4.7. Fluid compressibility

One of the parameters that must be inputted in SAPHIR for estimating the reservoir properties from the pressure transient data is the fluid compressibility. The analytical model does not account for the effect of CO_2 content on fluid compressibility. Thus it is crucial to examine the effect of different fluid compressibility values numerically. An experiment was carried out to see which compressibility value can give a more realistic estimation of parameters from the

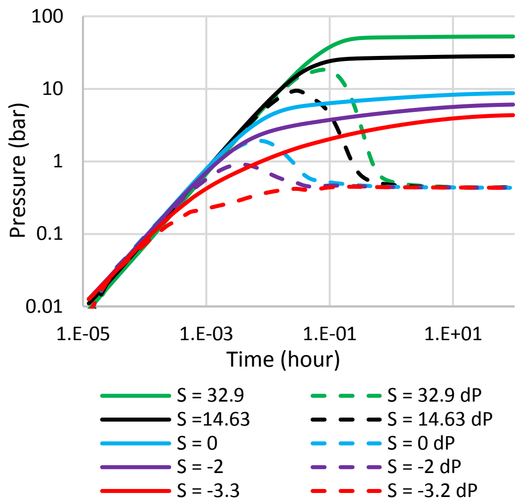

Figure 13. Pressure derivative plot: effect of varying skin block permeability.

analysis of the pressure derivatives. This was done by analysing the pressure response of 1%wt CO_2 model with different fluid compressibility in SAPHIR. The compressibility values tested are the compressibility values calculated for pure water and for water containing 1%wt CO_2, and 5%wt CO_2 calculated by using Equation (2), as is shown in Table 16.

Table 16. Fluid compressibility (Cc) used to SAPHIR.

Condition	Cc (Pa^{-1})
Pure water	1.320×10^{-9}
1% CO_2	1.579×10^{-7}
5% CO_2	3.158×10^{-8}

The analytical model results are shown in Table 17. The three models produced the same result for reservoir permeability, while they resulted in slightly different skin factors. The SAPHIR model using pure water fluid compressibility gave a closer match with the actual values inputted in TOUGH2, while the ones using dissolved CO_2 compressibility overestimated the skin factor. An experiment with injecting water at reservoir temperature also gave a similar pattern.

Table 17. SAPHIR's analytical model result for different fluid compressibility Cc.

Cc (Pa^{-1})	CO_2	*k* (mD)	Δ*k* (mD)	Skin	Δskin
1.320×10^{-9}	0 % CO_2	9.96	0.04	23.4	8.77
1.579×10^{-7}	1% CO_2	9.96	0.04	25.8	11.17
3.158×10^{-8}	5% CO_2	9.96	0.04	25	10.37

5. CONCLUSIONS

This work investigated the suitability of injection/falloff tests under multiphase and multicomponent conditions for reservoir fluid with dissolved CO_2. The effect of the variables on the PTA analysis and the characteristic appearance of the derivative plots were also assessed. The following findings can be observed:

CO_2 content for injection/falloff

The presence of dissolved CO_2 in the reservoir fluid has no significant effect on the characteristic appearance of the shape of the diagnostic plot and the estimated permeability from these plots. The skin factor estimated by the analytical model is slightly higher when the compressibility of water + CO_2 was used in the analytical models. However, if there is free CO_2 inside the geothermal reservoir, the pressure response is significantly affected, and the pressure derivative plot result cannot be analysed using the existing analytical model. This is because the flat line of infinite-acting flow has a much lower pressure derivative compared to the model without free CO_2. The attempt to calculate the reservoir properties using the semi-log method overestimated the reservoir permeability and skin factor.

Injectate temperature

The temperature difference between the injectate and reservoir fluid during the injection/falloff test affects the hump after a wellbore storage period. The higher the temperature difference, the bigger the hump, thus a higher skin will be inferred by the analytical model. This can mislead the interpretation of the pressure derivative plot results of the injection/falloff test.

For the case of injecting cold water into a reservoir containing free CO_2, the pressure derivative plot shows a larger hump after the wellbore storage period, but the flat line of the infinite-acting region remains at the same level. The results of these derivative plots cannot be analysed using the analytical model accurately.

Well block compressibility

A correct and consistent wellbore parameter is crucial in the numerical model setup for PTA, as the pressure derivative plot is very sensitive to the wellbore volume and the properties of the dedicated well block (e.g. well block compressibility). Model results show that the pressure response from the numerical model is sensitive to the well compressibility, and a higher well compressibility shifts the derivative plot to the right. Assigning an extremely small or extremely large well block compressibility caused an atypical pressure response.

Fluid compressibility

Using the compressibility of water + dissolved CO_2 resulted in slightly overestimated skin factor in the analytical model result. On the other hand, using the compressibility value of pure water gave estimated reservoir properties closer to the value used in the TOUGH2 model.

The experimental results of this study demonstrated that for reservoirs containing CO_2 the results of the analytical models should be evaluated with great caution as the assumptions that analytical models do not take into account can have critical importance when assessing the well test derived properties.

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