INJECTION OF CO_2 INTO LIQUID DOMINATED TWO-PHASE GEOTHERMAL RESERVOIRS

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ABSTRACT

Reinjection of CO_2 into geothermal reservoirs is receiving increasing interest from many industries to minimize the emission of the greenhouse gas into the atmosphere. The CO_2 could be injected in the form of gas dissolved in water or as super critical fluid. To understand the migration and impact of injected gases in the reservoir and forecast the effects on the reservoir pressure, production enthalpy and the potential breakthrough of reinjection fluid to the production wells, numerical reservoir simulation studies are required.

This work investigates the possible impacts of infield reinjection of CO_2 in two-phase liquid-dominated geothermal reservoirs using an earlier computer model of the Wairakei-Tauhara system (O'Sullivan and Yeh 2007) as a representative case study. Various reinjection scenarios were applied to test alternative reinjection strategies. Different injection rates of CO_2 were used along with the separated geothermal water and its effects on: reservoir pressure, temperature, production enthalpy, steam and CO_2 production were investigated. The breakthrough of CO_2 was also monitored since it can result in lower power recovery and higher gas (CO_2) production, hence higher practice load. The modelling results showed that the injection of CO_2 helps maintaining the reservoir pressure, but at the same time it suppresses boiling which results in reduction of the enthalpy of the produced fluid.

1. INTRODUCTION

Geothermal fluid contains Non-Condensable Gases (NCGs) such as carbon dioxide (CO_2), hydrogen sulfide (H_2S), ammonia (NH_3), hydrogen (H_2), nitrogen (N_2) and methane (CH_4). CO_2 is the most dominant gas which is ~90 % of the total NCGs by volume (Bertani and Thain, 2002), while H_2S constitutes ~2 to 3%, and the other gasses constitute the remaining volume. NCGs in the geothermal steam are conventionally removed from the condensers and discharged to the atmosphere.

Injection of CO_2 into deep formations is a common practice to enhance oil and gas recovery to extend the productive life of oil and gas reservoirs. NCG reinjection has been applied to geothermal reservoirs in few fields including: Hijiori, Japan (Yanagisawa, 2010); Ogachi, Japan (Kaieda et al., 2009); and Hellisheidi Iceland, (Alfredsson and Gislason, 2009), Coso, (Nagl, 2010; Sanopoulos and Karabelas, 1997) and Puna (Richard, 1990). Injected CO_2 could be in the form of super critical fluid or dissolved in water (brine). Injection of CO_2 with brine is preferred than single phase CO_2 injection. At Hijiori, Ogachi, and Hellisheidi, CO_2 was dissolved in water at very low concentrations (0.01 to 3 % by weight) prior to injection.

A brine-CO_2 mixture enhances residual trapping and avoids risk of gas leakage from the reservoir. There is also lower risk of salt precipitation due to formation dry-out (Hamidreza et al., 2015). However CO_2 and cold-water breakthrough may result to reduce the lifetime of the geothermal production wells.

The reinjection of NCGs requires reservoir modelling studies to understand the behaviour of injected gases in the reservoir and forecast possible NCG breakthrough to production wells. In this study, the effect of CO_2 injection in a liquid dominated geothermal reservoir was investigated. An existing computer model of the Wairakei-Tauhara field (O'Sullivan & Yeh, 2007) was used. An earlier work by Kaya et. al (2011) on the Wairakei-Tauhara model showed that high rates (more than 25% of separated geothermal water) of infield reinjection suppresses boiling and therefore decreases the average production enthalpy. Also colder injected fluid maintains reservoir pressure but suppresses deep hot water recharge to the system.

In the present paper we will consider only two-phase, liquid-dominated systems, using the Wairakei – Tauhara system as a hypothetical case study. Our aim is to investigate the effect of CO_2 and determine what the best reinjection strategy is for a system like Wairakei – Tauhara.

The injection of NCG gases will promote water-rock interactions when water flows through a permeable matrix in a geothermal system. These chemical reactions could result to a variety of precipitation, dissolution and rock alteration patterns that can change the porosity and permeability of the rock matrix. However the modelling of coupled flow and reactive transport is not considered in this study.

In liquid-dominated two-phase systems, when production commences, the steam fraction may increase, caused by pressure drops. At Wairakei, production has caused widespread pressure drawdown. The drawdown has stabilized at approximately 25 bar of the original reservoir pressure in the deep liquid zone of the Wairakei field. This large pressure drawdown has caused the formation of extensive two-phase zones (Mannington et al., 2004b), and in the formation of a shallow vapour-dominated zone in a pre-dominantly low enthalpy liquid-dominated system. The large pressure drop at the production wells and the boiling induced in the reservoir are not undesirable effects from a reservoir engineering point of view. A high enthalpy mixture of water and steam is an advantage because the conversion of thermal energy to electricity will be more efficient and less separated water has to be dealt with. However the large drop in reservoir pressure has resulted in significant subsidence (Allis, 2000; Bodvarsson and Stefansson, 1989).

This study investigates the effect of injecting a CO_2 and brine mixture on reservoir pressure, production enthalpy, steam production and breakthrough of CO_2 into the production wells. An infield reinjection area (close to production field) was used as reinjection site, and several rates of brine and CO_2 reinjection scenarios were simulated.

2. MODEL DESCRIPTION

An earlier version of the Wairakei-Tauhara model developed by O'Sullivan and Yeh (200 was used to represent liquid dominated two-phase reservoirs. It is a three-dimensional model that consists of an irregular grid structure having 312 columns and 32 layers with a total of 8055 blocks. Figure 1 shows the plan view and vertical grid structure of the computational grid. The area inside the resistivity boundary (shown with orange line in Figure 1) is represented by smaller grid blocks while the area outside the resistivity boundary has larger grid blocks.

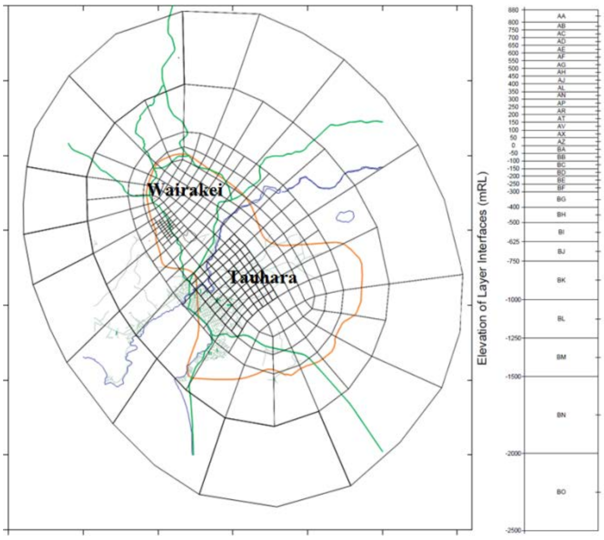

Figure 1 Areal and vertical grid structure of Wairakei-Tauhara Model.

The top surface of the model follows the topography of the Wairakei-Tauhara region. At the topmost boundary atmospheric conditions are maintained. The model developed by O'Sullivan and Yeh (2007) considers the flow of energy, water, and air within the geothermal system. Hence the model uses energy, water and air equation of state "EOS4". EOS4 enables the unsaturated zone close to the ground surface to be represented. In this study, the model was modified in order to include the effect of CO_2. Therefore in our model energy, water and CO_2 are the two components represented using the "EOS2" module for TOUGH2 (Yeh et al., 2012). Since the principal non-condensable gaseous component (NCG) is CO_2, and H_2S content by weight is much less, H_2S was not considered in the simulations.

2.1. Natural State

The Wairakei geothermal reservoir is characterized by high horizontal permeability, low vertical permeability, and low basement (bottom boundary) and cap-rock permeabilities. The reservoir permeability depends on the amount of faulting. The typical permeability values are high in the fractured production zone (horizontal permeability is 600-800 mD) while a low permeability is dominant in the cap rock (< 1 mD) (Mannington et al., 2004b).

A heat flux of 0.08 W/m^2 was assigned to the bottom boundary of the model to represent the normal terrestrial heat flow. A deep hot mass recharge is located at the base of the model. Cold ground water recharge through surface waters (rivers, lakes) and rainwater infiltration were implemented. Surface outflow to hot spring is represented in the model by mass flow rates from beneath the cap rock (Layer AP, +275 masl).

The calibrated natural state model agrees well with reservoir temperatures, surface outflow locations and vapour saturations (Bixley et al., 2009; O'Sullivan and Yeh, 2007).

In order to represent CO_2 and water flow in the model, the top surface was maintained at atmospheric conditions of a total pressure of 1 bar with a CO_2 partial pressure of 0.9965 bar, giving a partial pressure of water vapour corresponding to 15°C, was applied. The unsaturated zone between the water table and ground surface contains CO_2 (not air), since the equation of state used has no air.

At the bottom boundary of the model no CO_2 injection were considered for the natural state model to represent deep inflow of CO_2. Hence initial CO_2 of the reservoir is zero.

2.2. Production Model

For the production model of the Wairakei-Tauhara system, the historical data for production and reinjection at the Wairakei field are used as input in the model. For the air water model calibrated by O'Sullivan and Yeh (2007), the initial conditions for the production model are taken from their natural state model. O'Sullivan and Yeh (2007) (Mannington et al., 2004b) carried out calibration to obtain a match of the model behavior to the measured changes in pressures, average production enthalpies, surface heat flows, temperatures and vapour saturations. For this study the initial conditions resulted from CO_2 inclusion were considered. Our investigations showed that replacing air with CO_2 did not cause significant changes to the production enthalpy, pressure and temperature of the reservoir.

The production wells are grouped under five main areas based on their locations; Western Borefield (59 wells), Eastern Borefield (24 wells), Te Mihi (31 wells), Waist (2 wells) and Poihipi (5 wells). Almost all of the production is taken from between +100 to -500 masl (300 and 900m depth). When the model (O'Sullivan and Yeh, 2007) was developed, the field was producing for over 50 years. Most of the mass produced was from the Western Borefield (Figure 2). Extraction in the Eastern Borefield has declined while extraction in Te Mihi has increased in the last 20 years.

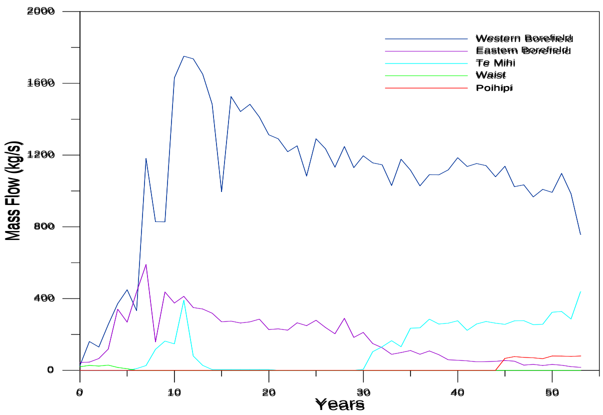

Figure 2 Total production histories for the production areas at Wairakei-Tauhara

The production enthalpy has been stable in the Western Borefield while it is fluctuating at the Eastern Borefield and Te Mihi. The Poihipi wells produce dry steam with high enthalpy.

For about the first 40 years of production in the Wairakei Tauhara field the bulk of the cooled geothermal fluid (both condensed steam and the separated brine) was discharged into the Waikato River (Bixley et al. (2009)). Then for the following 10 years a small amount of the separated geothermal water (SGW) was reinjected close to the Eastern Borefield. As a result of this strategy, a large two-phase zone, with a high vapour saturation in some locations, has formed and the enthalpy of some of the production wells has increased (Mannington et al., 2004b). Additionally there has been a large drawdown in the reservoir pressure. This has induced an increase in the deep hot recharge to the field. After 30 years of production, the pressure drawdown in the deep liquid zone stabilized at about 25 bar (Bixley et al., 2009; Mannington et al., 2004b). The actual injection scenario that was implemented in Wairakei-Tauhara is referred as the BASE model.

3. REINJECTION SCENARIOS

In this section the scenarios used in an investigation of alternative reinjection strategies for Wairakei-Tauhara are described. With the scenarios summarized in Table 1, our particular interest is to decide if injection of CO_2 in the geothermal reservoir is feasible. As shown in Table 1, for brine reinjection scenarios, the reinjection rates of 100%, 50% and 25 % of SGW (named as in100, in50 and in25 respectively) were used. Here the SGW represents the total amount of water produced from the separators (calculated by subtracting the amount of produced steam from the amount of total produced mass).

Table 1 Summary of the reinjection scenarios used in the simulations

Scenario name	Reinjection Strategy
BASE	Actual reinjection history (no reinjection for 40 years, followed by a small amount of reinjection for about the last 10 years.
in25	Infield injection of 25% SGW
in50	Infield injection of 50% SGW
in100	Infield injection of 100% SGW
10% CO_2	Mass of injected CO_2 is 10% of injected SGW (for in25, in50, in100 scenarios)
5% CO_2	Mass of injected CO_2 is 5% of injected SGW (for in25, in50, in100 scenarios)
1% CO_2	Mass of injected CO_2 is 1% of injected SGW (for in25, in50, in100 scenarios)

For the scenarios described in Table 1 with regard to CO_2-water mixture reinjection, three different assumption of CO_2 content of reinjection fluid were tried for each brine reinjection scenario. E.g. for the "10% CO_2" scenario, the mass of injected CO_2 was assumed to be 10% of injected SGW, and this CO_2 content were considered for the three cases of SGW reinjection rate (in25, in50, in100) separately.

The impact of various reinjection rates of SGW and CO_2 –the water mixture ratio - on production enthalpy, steam production, reservoir pressure and flow of CO_2 in the reservoir were investigated. The total reinjected water is distributed into the infield reinjection grid-blocks in proportion to their volumes.

Injection of the steam condensate produced from the field was not considered in these scenarios. The enthalpy of the reinjection fluid was taken as 564.4 kJ/kg, corresponding to the average temperature of the fluid from the separators of about 134°C.

The areal and vertical locations of the injection are shown in Figure 3. The selection of the reinjection zone were based on studies by O'Sullivan (2006) and Kaya et al. (2011), considering permeability of injection zones and distance from the production area. Table 2 shows horizontal distances between the production and injection zones. Because of the permeable connection between these zones, the possibility of the rapid breakthrough of cool injected water is a major concern.

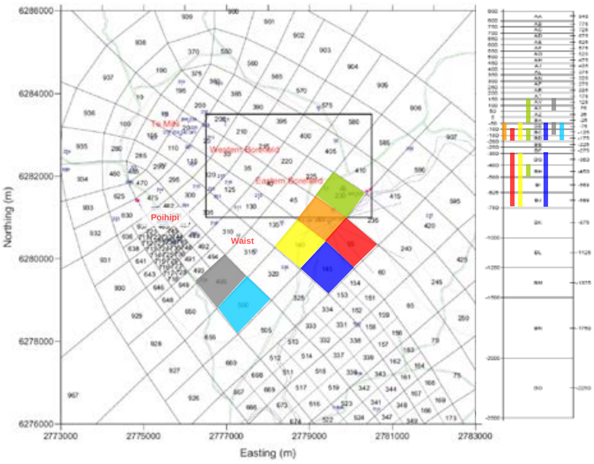

Figure 3 Areal and vertical location of infield reinjection (Kaya, 2010)

Table 2 Horizontal distances between the production and injection zones (Kaya, 2010)

Production area	**Closest and farthest distance from reinjection zone, m**
Eastern Borefield	0 - 1560
Waist	970 - 1210
Poihipi	1245 - 3810
Te Mihi	1450 - 4700
Western Borefield	2215 - 2860

4. RESULTS AND DISCUSSION

4.1. Injection of SGW with 10% CO_2

In this section, the impact of different rates of brine reinjection, with inclusion of 10% wt CO_2, on production enthalpy, reservoir pressure, separated steam production and CO_2 flow is discussed.

4.1.1 Pressure

Increasing the amount of brine injection resulted in higher reservoir pressures in both the Western (Figure 4) and Eastern (Figure 5) Borefields. Additional injection of CO_2 further increased the reservoir pressure. In the Western Borefield,

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CO_2 injection provided significant pressure support between 10 to 25 years of operation. However, after about 45 years, reservoir pressure with or without CO_2 injection is the same. Although the Eastern Borefield is closer to the reinjection zones (Figure 3) the pressure support due to CO_2 injection is less on lower rates of reinjection scenarios (IN50 and IN25). This can be due to the smaller production rate at the Eastern Borefield.

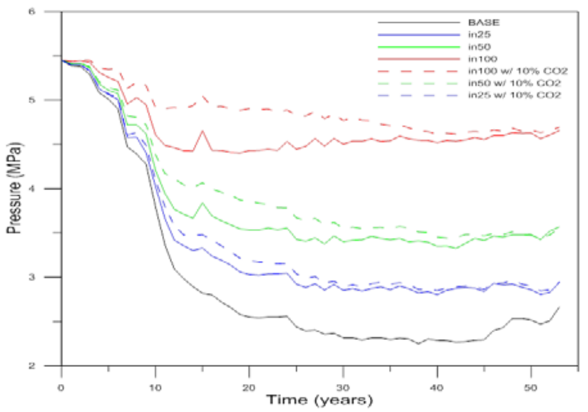

Figure 4 Western Borefield reservoir pressure.

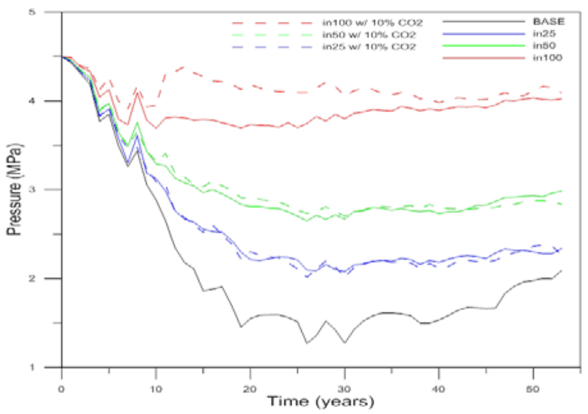

Figure 5 Eastern Borefield reservoir pressure

4.1.2 Enthalpy

The Western Borefield has a declining enthalpy trend for both BASE and infield injection scenarios (Figure 6). The lowest discharge enthalpy was obtained at 100% SGW injection. CO_2 injection for the in100 scenario resulted in a significant additional decline in enthalpy. Steam fraction decreases significantly after 50 years at the shallow production zones (e.g. +175 masl), while boiling is completely suppressed and no steam present at the deep production zones (-125 masl).

In the Eastern Borefield, enthalpy increases after 10 years of production, due to the formation of high vapour saturation zones for the BASE case (Figure 7). The fluctuations indicate boiling in this production area. All injection scenarios resulted in lower enthalpy within 10 to 40 years of production. Here the enthalpy changes occur under the effects of several parametes:

1- Boiling point of the water containing CO_2 is different from that of pure water. The presence of CO_2 promotes boiling.

2- An increase in the reinjection rate increases the pressure support (Figure 5) and prevents the formation of high vapour saturation zones.

3- Additionally this pressure support prevents the recharge of deep hot fluid into the reservoir.

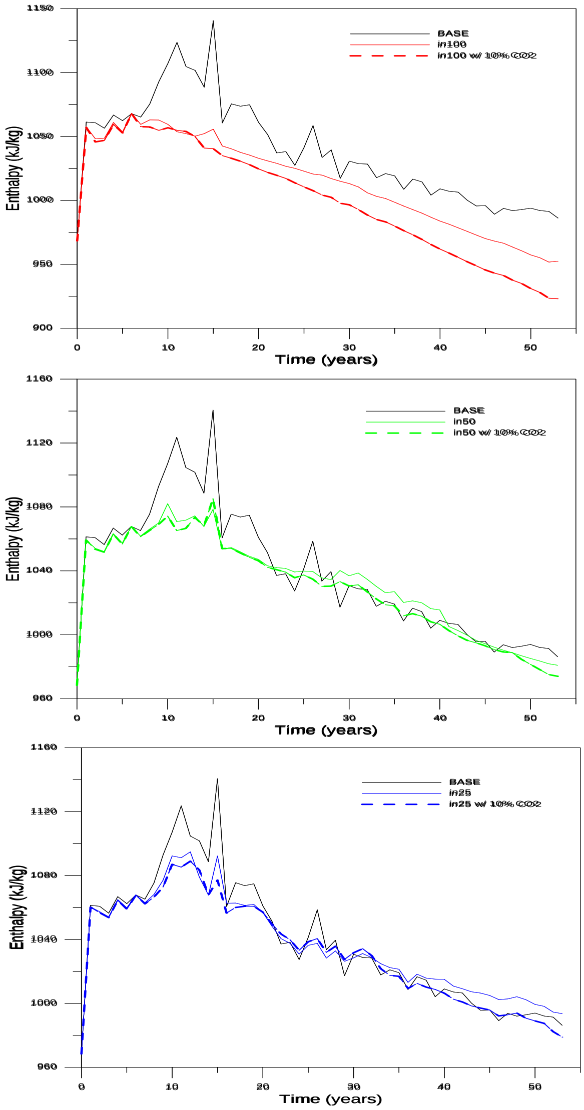

Figure 6 Western Borefield discharge enthalpy

In the last 5 years of production, in25 and in50 scenarios ended up with the similar enthalpy with BASE case. For the in100 scenario, CO_2 injection resulted in a lower enthalpy. For in25, CO_2 injection resulted in a higher enthalpy within the 10 to 45 years period. After 45 years, enthalpy stabilized giving same values for both BASE and infield injection scenarios. The presence of CO2 will increase the boiling pressure compared to that of pure water.

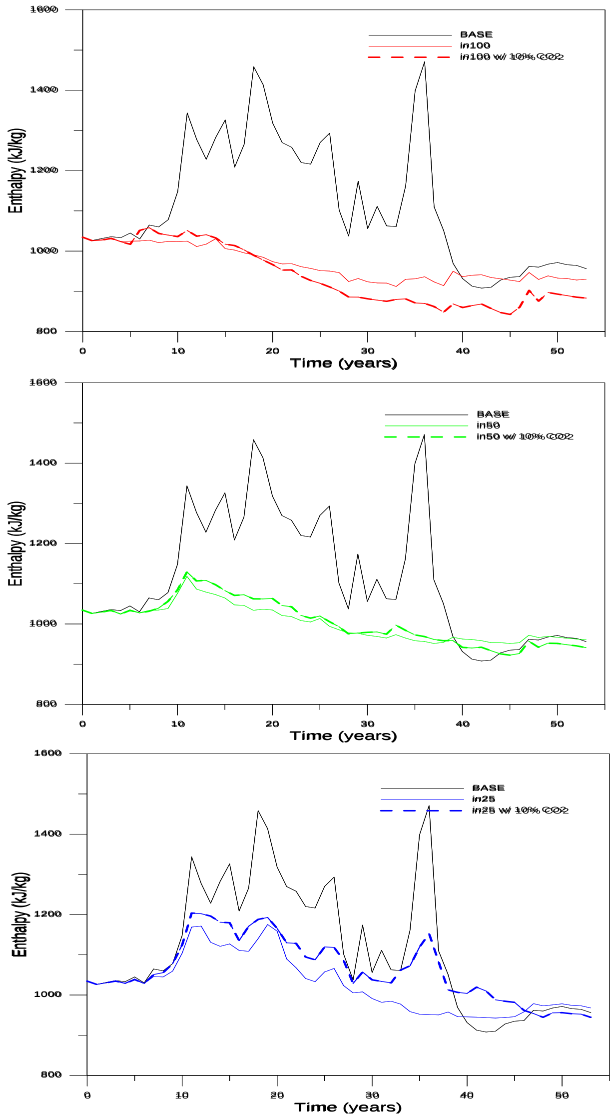

Figure 7 Eastern Borefield discharge enthalpy

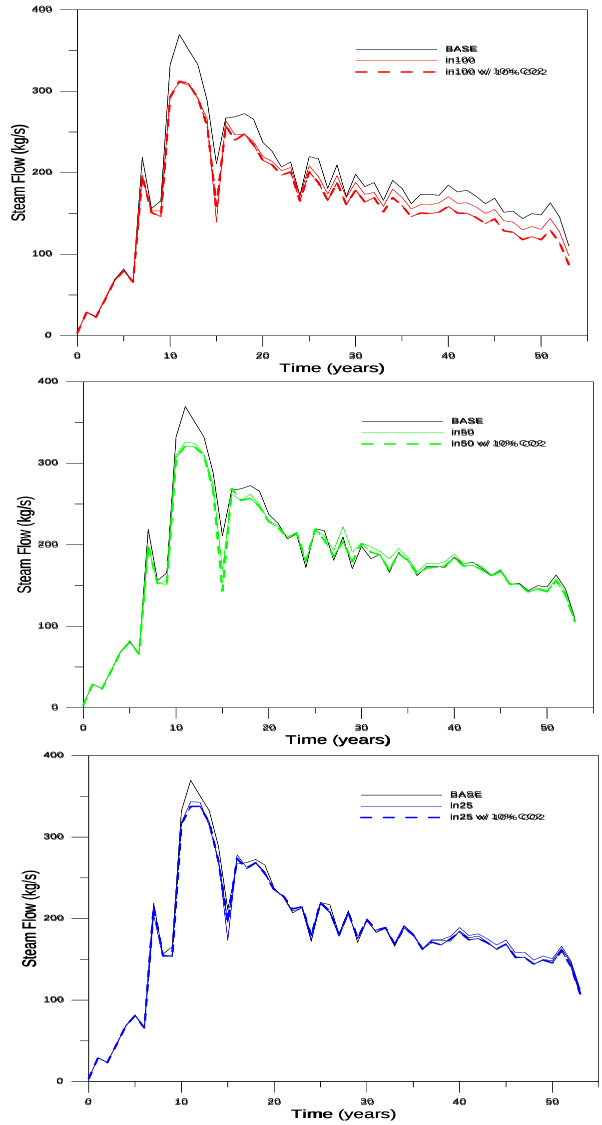

Figure 8 Western Borefield separated steam production

4.1.3 Separated steam production

In order to see the effect of different reinjection scenarios with the inclusion of 10% by weight CO_2 injection on steam production, separated steam flow histories were plotted. The steam flow was calculated from the mass flow using a separator pressure of 6.5 bar.

In the Western Borefield (Figure 8), the in25 and in50 scenarios with CO_2 injection have no significant effect on steam flow. However, for in100, a lower steam flow was obtained. CO_2 injection for in100 also resulted in additional decline in steam flow associated with additional pressure support to the reservoir due to CO_2 injection.

In the Eastern Borefield, a significant steam flow decline was noted for all injection scenarios during the 10 to 40 years period (Figure 9). For in100, CO_2 injection resulted in a lower steam flow. The opposite effect was noted at in25 where CO_2 injection resulted in a higher steam flow. For in50, a small increase in steam flow was also observed within 15 to 25 years of production.

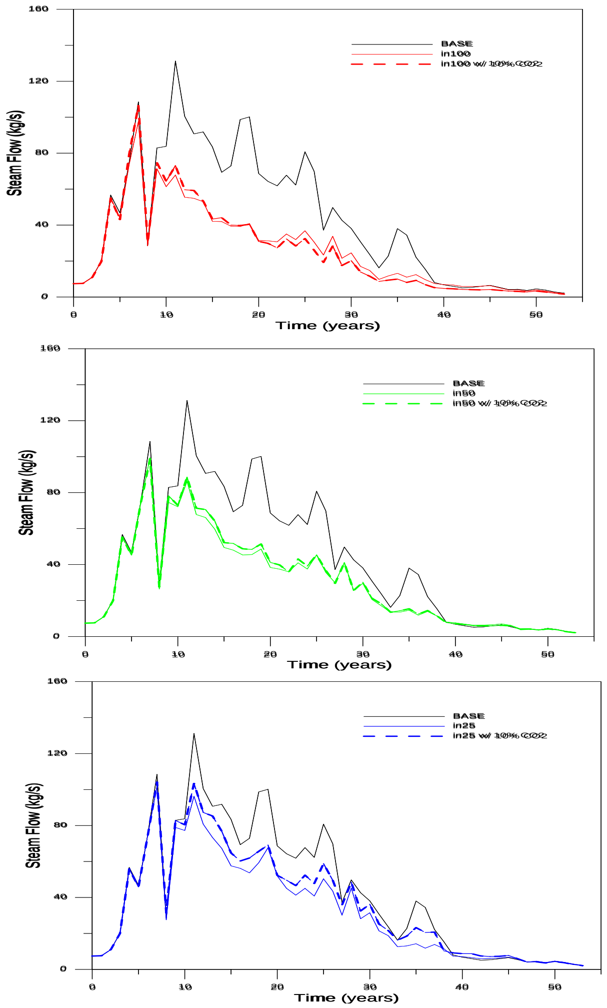

Figure 9 Eastern Borefield separated steam production

4.1.4 CO_2 Production

With CO_2 injection, CO_2 production starts to increase after 5 years in the Eastern Borefield and after 10 years in the Western Borefield. CO_2 breakthrough is faster in the Eastern Borefield due to its distance from the injection zones (Figure 10). The decline in CO_2 flow after 47 years in the Eastern Borefield is due to the decline in the mass extracted. Since an increase in the rate of reinjection increases the CO_2 content in the reservoir, it causes an increment on the CO_2 production (Figure 11).

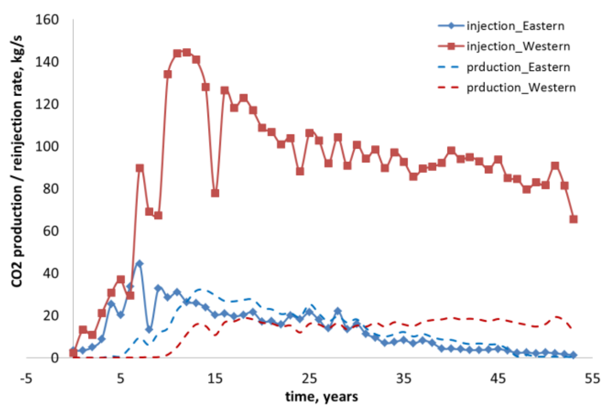

Figure 10 CO_2 reinjection (10% of SGW) and production rates at the Western and Eastern Borefield for in100

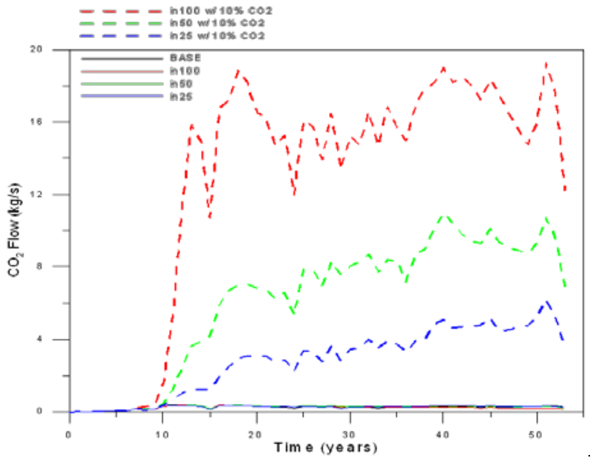

Figure 11 Western Borefield CO_2 production for in25, in50, in100 scenarios

The build-up of CO_2 in the reservoir is shown in Figure 12 for in100 scenario. At the start of the simulation, the CO_2 content of the reservoir is negligible. After 53 years of injection, a significant amount of CO_2 is present in both reinjection and production zones.

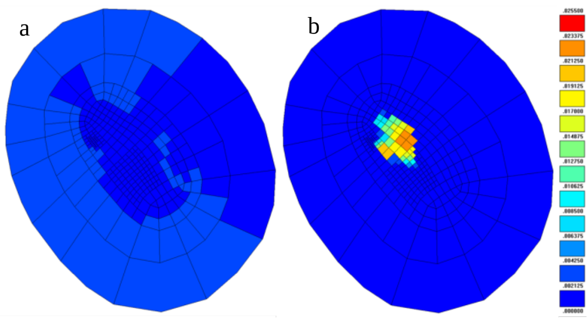

Figure 12 CO_2 mass fractions in layer BD at (a) initial conditions (b) after 53 years of CO_2 injection for in100

A vertical slice drawn NW-SE along the Wairakei area shows the mass fraction of CO_2 in the reservoir (Figure 13). The majority of the CO_2 is located on the upper portion of the reservoir below the cap rock. It should be noted that the low CO_2 content at the very shallow zones may be due to the assumption of having a large content of CO_2 in the atmosphere. Possibly during production, due to pressure drop, any outflow may reverse to inflow and increase CO_2 content of the shallow zones upper in the model.

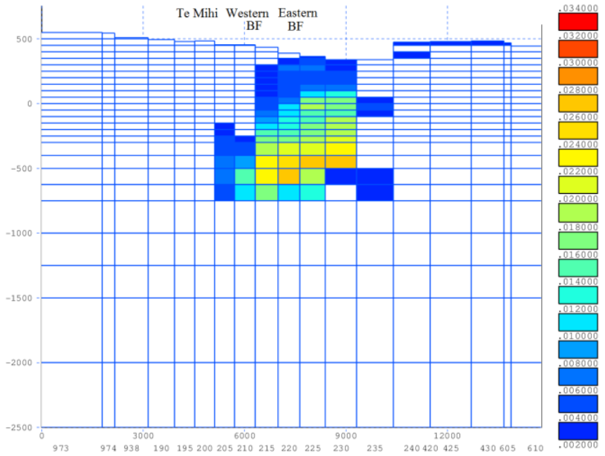

Figure 13 NW-SE Vertical slice view of the CO_2 mass fraction at 53 years for in100

4.2. Varying amounts of injected CO_2 (10%, 5% and 1%)

4.2.1 Pressure

Higher amounts of CO_2 injection resulted in higher reservoir pressure in both the Western (Figure 14) and Eastern (Figure 15) Borefields. In the last 10 years of production, the effect of CO_2 injection to reservoir pressure becomes smaller.

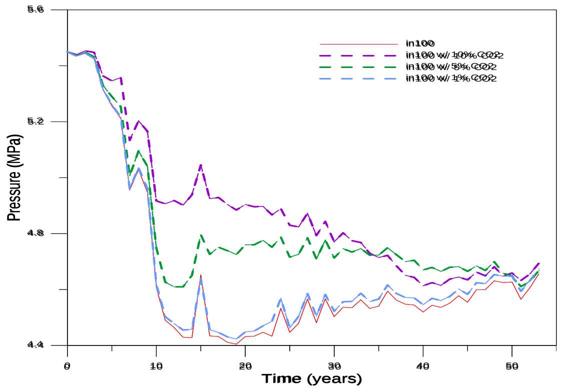

Figure 14 Western Borefield pressure at 1%, 5% and 10% CO_2 injection for in100

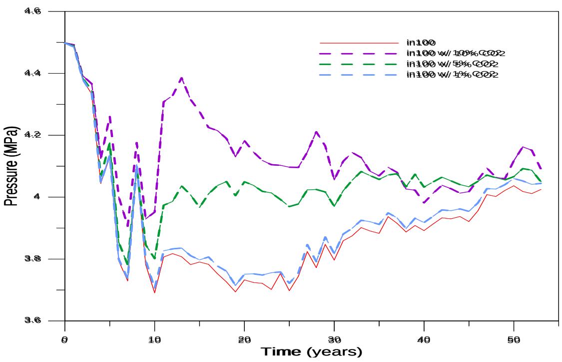

Figure 15 Eastern Borefield pressure at 1%, 5% and 10% CO_2 injection for in100

4.2.2 Enthalpy

At 100% injection of SGW, CO_2 injection resulted in a further decline in average production enthalpy. Similar behavior was observed for the Western Borefield, even for a low rate of SGW reinjection scenario. However increasing the CO_2 content caused an increase in the enthalpy of the Eastern Borefield (Figure 16, Figure 17)

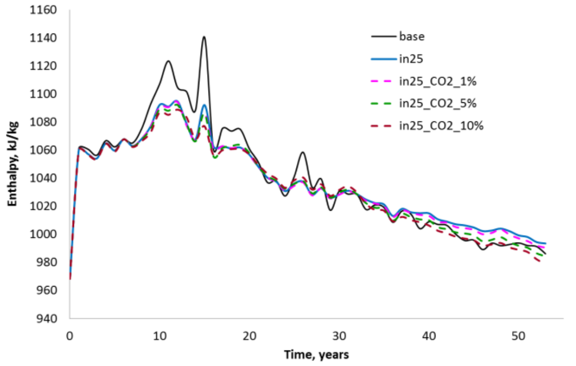

Figure 16 Western Borefield enthalpy variations for 1%, 5% and 10% CO_2 injection for in25

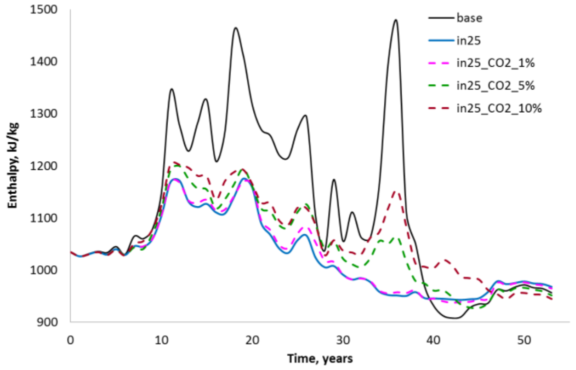

Figure 17 Eastern Borefield enthalpy variations for 1%, 5% and 10% CO_2 injection

4.2.3 CO_2 Flow

The amount of CO_2 produced is also proportional to the amount of CO_2 injected. Both Western (Figure 18) and Eastern (Figure 19) Borefields produced higher CO_2 at higher injection rates. The Eastern Borefield has a faster CO_2 breakthrough of 5 years and higher CO_2 production rates than injected CO_2 rate, due to its close proximity to the reinjection sector. Also, the presence of CO_2 promotes boiling which concentrates the CO_2 in the liquid phase.

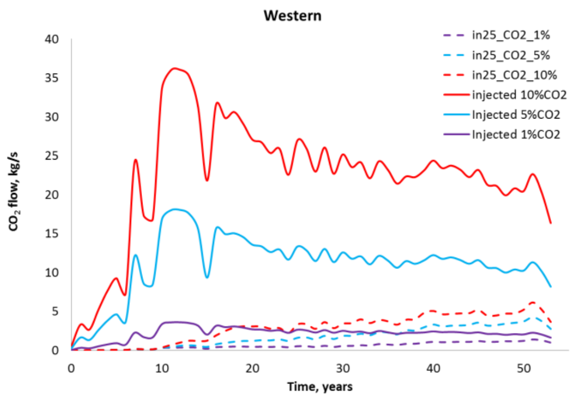

Figure 18 Western Borefield CO_2 flow at 1%, 5% and 10% CO_2 injection for in25

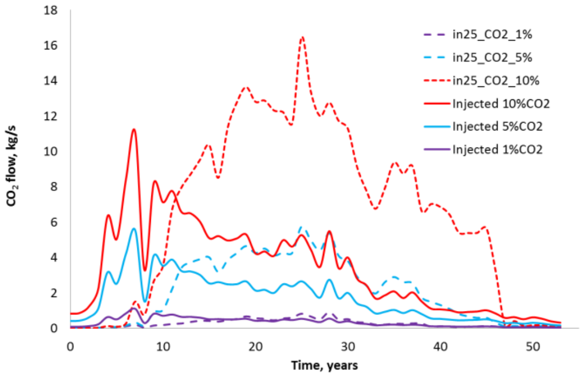

Figure 19 Eastern Borefield CO_2 flow at 1%, 5% and 10% CO_2 injection

4.2.4 Separated steam production

In order to see the effect of CO_2 injection on overall power generation, steam production histories were plotted. Figure 20 shows the effect of varying the CO_2 content for in25 scenario on the Western and Eastern Borefield. According to this figure, for the low rate of SGW reinjection (in25) and up to 10% CO_2 rate, CO_2 injection does not affect the Western Borefield steam production, while it shows a positive impact on the Eastern Borefield steam production.

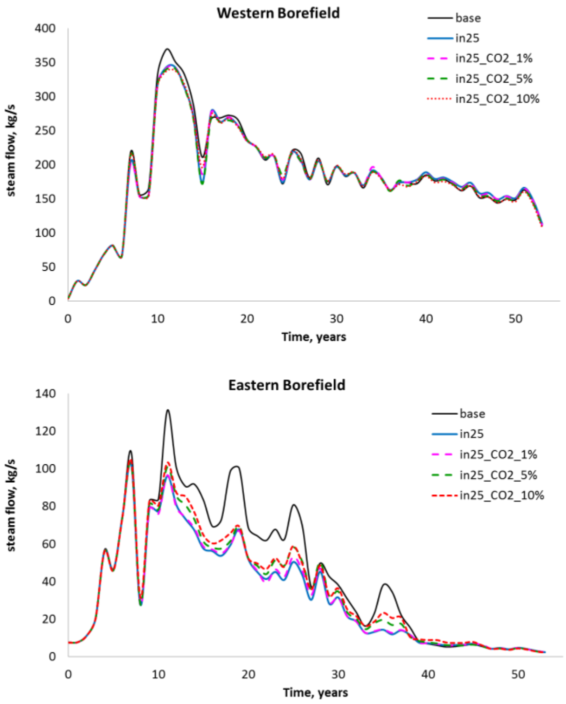

Figure 20 Separated steam production histories for the Western and Eastern Borefield for in25 with three different rate of CO_2 reinjection

Results indicate that increasing SGW reinjection rate suppresses boiling and decreases steam production, however the addition of extra CO_2 into SGW for in25 and in50 scenarios causes higher steam production histories (Figures 21 and 22).

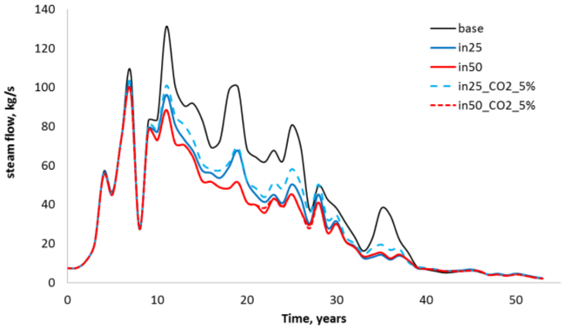

Figure 21 Separated steam production histories for the Eastern Borefield for in25 and in50 with 5% CO_2 content

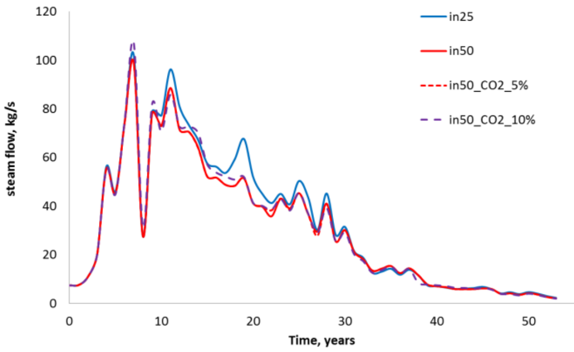

Figure 22 Separated steam production histories for the Eastern Borefield for in25 and in50 with 5% AND 10% CO_2 content

The effect of the enthalpy of injected CO_2 is also investigated. Enthalpy values of 650 kJ/kg and 365 kJ/kg were tried based on the range of injection temperature and pressure parameters. The average production enthalpy in the Western and Eastern Borefields remained the same at different CO_2 injection enthalpy. Therefore, the enthalpy of CO_2 has negligible effect on the production enthalpy since the amount of injected CO_2 is relatively smaller compared to the amount of injected brine.

5. SUMMARY AND CONCLUSION

The high permeable connection between the reinjection zones and production areas, allowed the infield injection of brine to prevent a large pressure drop in the reservoir. The addition of CO_2 into reinjection fluid provided additional pressure support. This effect is more apparent on the production sectors that are adjacent to the reinjection areas.

Supporting reservoir pressure via reinjection of CO_2-brine mixture suppressed boiling and reduced the formation of steam zones. It also prevents natural hot recharge to the system from depth. The average production enthalpy obtained from different CO_2 injection scenarios was lower than the actual (brine only) injection strategy for the Wairakei-Tauhara field (BASE scenario). For the high rate of SGW reinjection (in100), increasing the CO_2 content of the reinjection fluid decreased the average enthalpy. For the lower rate reinjection scenario (in25), increasing the CO_2 rate caused a small decrease in enthalpy in the Western Borefield while causing an increase in the average enthalpy in the Eastern Borefield. Steam flow followed a similar trend with enthalpy.

CO_2 breakthrough occurred after 5 years in Eastern Borefield which is located nearest to the injection area while it took ~10 years to observe the CO_2 breakthrough in the Western borefield. CO_2 flow continued to increase after breakthrough was observed in the production areas. Breakthrough of CO_2

should to be avoided as it results in lower heat recovery and higher gas production. This could be avoided by moving the injection area further away from production zones or by reducing in injection rate.

This modeling study shows that infield reinjection of NCG's in a highly permeable field like Wairakei has undesirable effects on the long term sustainability of the resource. If NCG reinjection is to be considered in the future it should be in limited amounts or reinjection should take place outfield.

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