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Study of Production-Injection Strategies for Sustainable Production in Geothermal Reservoir Two-Phase by Numerical Simulation

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Abstract - The rapid pressure decline in liquid-dominated geothermal fields is a significant problem affecting the steam supply to the power plant. This study aims to understand the reservoir characteristics changes due to extraction of mass and heat from the reservoir through a numerical reservoir simulation under various strategies production-injection. The development of a liquid-dominated geothermal field model is assessed with various production strategies and injection strategies for the generation of 110 MW and 220 MW using a separated steam cycle. Thirty two production-injection strategies from a full factorial have been successfully carried out. The results show a low decrease for both reservoir pressure and decline rate for the steam cap and brine reservoir's production strategy combined with deep and dispersed injection strategy. From a simulation for 220 MW, the strategy for sustainable production is 25% from the steam cap and 75% from brine reservoir, dispersed, and deep reinjection with 9 make-up wells from the steam cap. The lowest decline rate after the 30th year is 0.5%, with Arps 1.0 exponent harmonic decline curve. The implementation of the production-injection strategy needs to be planned from the beginning of exploration or exploitation so that the strategy can be adjusted to changes in reservoir characteristics without causing problems.

Keywords: reservoir liquid-dominated, steam cap, decline, numerical simulation, sustainable production

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Introduction

The liquid-dominated hydrothermal reservoir is most developed for power plant generation. The sustainable steam production from this type of reservoir had been a significant concern, then a large amount of mass production from the reservoir can significantly decline reservoir pressure over time. The pressure drop simultaneously can induce a reservoir to boil. According to Grant *et al*. (1982 and 2011), two possibilities could occur in the liquid-dominated reservoir after production. The steam is mixed homogeneously, and the fluid dryness around the production well surges. Another possibility is that the steam zone and water zone will be separated due to gravity; therefore, the steam cap is formed at the top of the reservoir. With an excellent vertical permeability, the reservoir boiling causes the steam, which has a lower density than the liquid phase, to move up, and is formed at the top reservoir. Both of this process arises in most areas or the whole reservoir. This phenomenon occurred in several geothermal fields with high power plant capacity, such as Wairakei - New Zealand (Grant *et al*., in 1982 and 2011; Clotworthy, 2000; Mannington *et al*., 2004; Bixley *et al*., 2009), Tongonan - Philippines (Salonga, 1999; Seastres *et al*., 2000; Gonzalez *et al*., 2005; Dacillo *et al*., 2010), Awibengkok - Indonesia (Stimac *et al*., 2008; Acuña *et al*., 2008; Ganefianto *et al*., 2010), and Wayang Windu - Indonesia (Mulyadi and Ashat, 2011).

Common practice from numerous fields, such as Wayang Windu and Awibengkok, steam cap zone is more beneficial to produce because it is shallower than brine reservoir; therefore, from the drilling point of view, the drilling cost can be reduced. The injection wells and separators could be reduced because the flow rate of liquid is less produced. This potential cost reduction from a geothermal developer's point of view makes mass and heat production from a steam cap somehow more exciting.

The number of researches in a numerical simulation developed for the liquid-dominated reservoir is less than those for liquid phase reservoir or vapor-dominated reservoir. The liquid-dominated reservoir can be more challenging to model since one has to construct a vapor-dominated reservoir model underlying a liquid-dominated reservoir. Some results from the study were given by O'Sullivan *et al*. (2000) who encountered difficulty in modelling these types of a reservoir. The simulation was run under a variety of production-injection strategies. By monitoring pressure and temperature drop, vapor saturation, and mass flow in the reservoir model as a function of time, this model can predict the reservoir performance with various production-injection strategies to exploitation time.

Three production strategies, presented in this study, were produced from steam cap only, a fluid produced from the brine reservoir, and fluid produced from both steam cap and brine reservoir. There are two strategies for the injection strategies, such as; fluid injection into both deep shallow reservoirs and peripheral injection strategy both centered or dispersed.

This study aims to obtain optimal production-injection strategy and make-up well strategy in order to manage the mass and heat production from the reservoir for sustainable geothermal field management.

Methodology

The synthetic numerical reservoir model was developed based on the characteristic of the typical two-phase liquid-dominated reservoir. Using four different strategies, both production, and injection for 110 MW and 220 MW of power generation, the model was run for 32 strategies by full factorial. Further study was to predict the reservoir performance for 30 years. The well make-up scenario is to produce them either from the brine reservoir, steam cap, or combined to sustain steam the steam supply for power generation of 220 MW.

Conceptual Model

The synthetic model conceptual is based on reservoir characteristics of Wairakei - New Zealand Tongonan - Philippines, Awibengkok - Indonesia, and Wayang Windu - Indonesia. It is the liquid-dominated geothermal field that has a steam cap underlying brine reservoir. The model has characteristics shown in Table 1. The six exploration wells showed high temperatures in the center of the reservoir, and the other wells have lower temperatures because they are located near the reservoir boundary (Figure 1).

Table 1. Characteristics of the Synthetic Model

Reservoir	Steam cap	Brine reservoir
Proven Area	13 km^2	23 km^2
Temperature	240^{o}C	240-320^{o}C
Pressure	34 bar	Brine res. = 55 bar
Thickness	500-1000 m	1400-1500 m

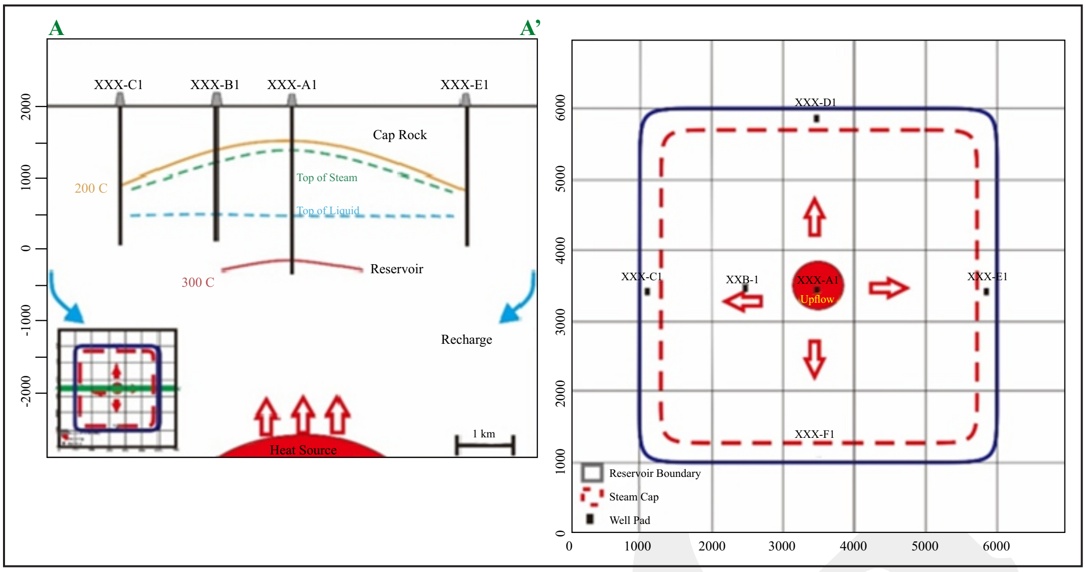

Figure 1. Conceptual model of the synthetic reservoir (Pratama and Saptadji, 2016).

Results and Analysis

Natural State

The computer model was based on Pratama and Saptadji (2016) research, and it was built using TOUGH2 with EOS1. Table 2 shows each rock properties, which represent geological conditions with single porosity and distributed permeability along with the geothermal reservoirs.

Table 2. Material Data for a Computer Model

Material Type Legend		Rock Density (kg/m³)	Porosity	Permeability (m^2) XY	Permeability (m^2) Z
Atmosphere		2600	0.99	1E-10	1E-12
Ground Water		2500	0.02	2E-18	2E-18
Caprock		2600	0.05	1E-18	1E-18
Boundary1		2600	0.001	1E-19	2E-19
Boundary2		2600	0.01	1E-20	1E-20
Heat source		2650	0.07	1E-14	1E-15
Reservoir1		2500	0.25	1E-13	5E-14
Reservoir2		2550	0.2	8E-14	4E-14
Reservoir3		2600	0.15	6E-14	3E-14
Reservoir4		2600	0.15	5E-14	2E-14
Reservoir5		2600	0.1	3E-14	1E-14
Reservoir6		2600	0.1	9E-15	6E-15
Reservoir7		2600	0.1	7E-15	3E-15
Reservoir8		2600	0.09	5E-15	2E-15
Reservoir9		2500	0.05	3E-17	1E-17

The boundary conditions, such as outside boundary, heat source, and atmosphere, were assigned in this model. The purpose is to create an initial condition for a model. The subsurface is full of uncertain information; therefore, the data input is very tricky. Each block's properties should be adjusted and repeated until the reservoir model can represent their natural conditions. The output of pressure and temperature from the model shown in Figure 2 have good alignment with actual data. The model represents a steam cap underlying the brine reservoir. This natural state at the steam cap zone has a similarity with the conceptual model of vapor-dominated proposed by White *et al*. (1971), and enhanced by D'amore and Truesdell (1978), and Goff and Janik (2000), which is shown in Figure 3. The conductive heat transfer occurred in a heat source into a reservoir, and convective heat transfer occurred in the entire steam cap reservoir. Steam saturation was formed at the steam cap zone is 80%, which is close to a value of 85% of the vapor-dominated geothermal field by Allis (2000).

Field Development Plans and Production-Injection Strategies

For a conversion cycle, a single flash steam by DiPippo (2008) was used. Wellhead pressure, separator pressure, turbine inlet pressure, condenser

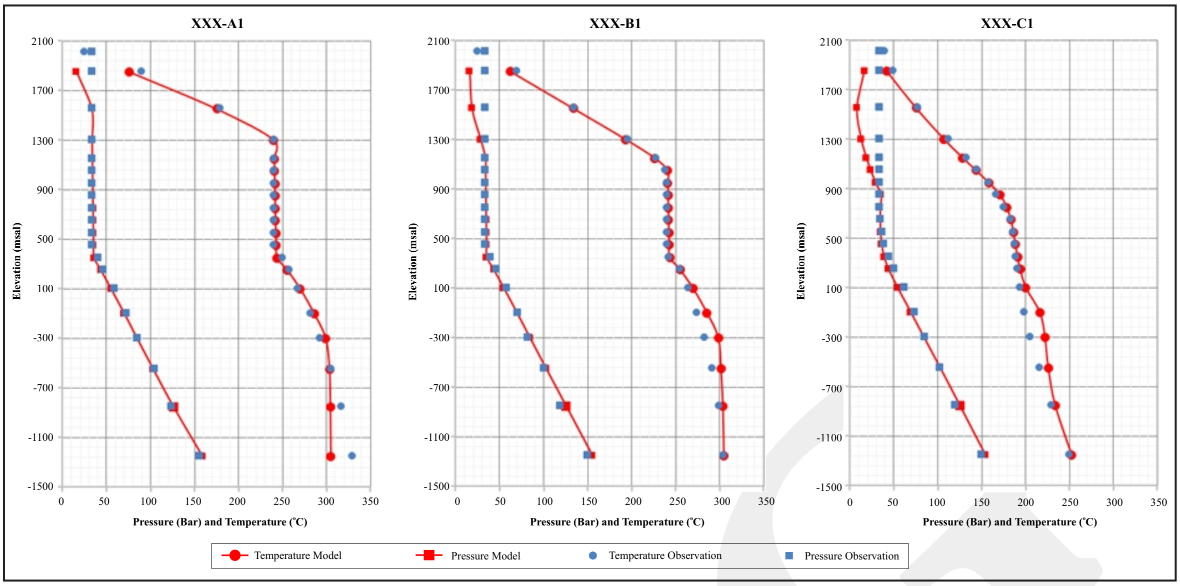

Figure 2. Matching pressure and temperature data model and actual well data (Pratama and Saptadji, 2016).

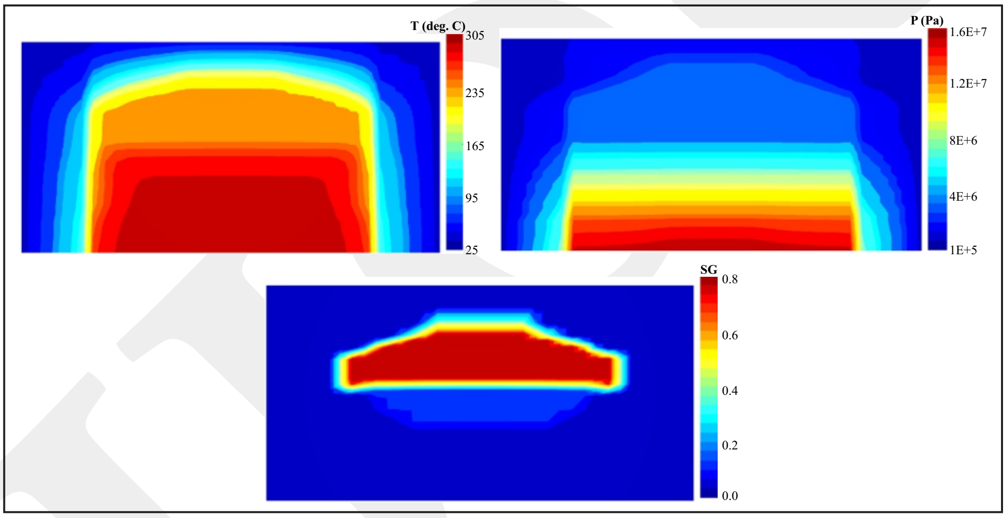

Figure 3. Natural state condition, temperature (top), pressure (middle), steam saturation (bottom) (Pratama and Saptadji, 2016).

Table 3. Design and Steam Consumption Calculation for Power Plant

Design	WHP (bar)	$P_{Separator}$ (bar)	TIP (bar)	$P_{Condensor}$ (bar)	$\eta_{Turbine}$	$m_{steam\ total}$ (kg/s)	SSC (kg/s/MW)
110 MW	12	10.6	10	0.1	80%	199	1.8
220 MW	12	10.6	10	0.1	80%	397	1.8

pressure, and specific steam consumption (SSC) resulting as a result of calculation for 110 MW and 220 MW are shown in Table 3. The production capacity for both steam cap and brine production is 20 kg/s and 40 kg/s, respectively, while the dryness is 0.37 and 0.82 at the wellhead. The injection capacity for each well is 100 kg/s both for steam condensate from the cooling tower and brine from the separator.

This study used four production strategies to learn the behavior of a two-phase reservoir with the steam cap at the top of the reservoir; the production strategy is focused on 100% from a steam cap, 100% from a brine reservoir, the combination from 50% of the steam cap + 50% of brine reservoir, and the combination form 25% of the steam cap + 75% of brine reservoir.

The four injection strategies are:

1. Centered injection (single well pad for each brine and condensate).
2. Dispersed injection (multiple-well pad for brine injection and single well pad for condensate, both areas are surrounding the reservoir)
3. Shallow injection (both separated brine and condensate injected into the liner of 1100 - 400 masl or 900 - 1600 m depth).
4. Deep injection (both separated brine and condensate injected into the liner of 300 - (-500) masl or 1700 - 2500 m depth).

The results of calculation, design, and the number of wells from both production strategies and injection strategies are shown in Table 4. The 32 models and simulations have been carried out for full factorial from 4 parameters (Table 5). The numerical simulations used both constant flow rate and well deliverability method. The pressure and temperature at both the steam cap and brine

Table 4. Mass Flow and the Number of Well for 110 MW

110 MW	100% Brine	100% Steam	Combination 1		Combination 2	
			50% Steam	50% Brine	25% Steam	75% Brine
Production Well (110 MW)	13	12	6	7	3	10
Production Well (220 MW)	26	24	12	13	6	20
Brine Injection Well (110 MW)	3	1	2		3	
Brine Injection Well (220 MW)	6	1	3		6	
Condensate Injection Well	1	1	1		1	

Table 5. The 32 Models of Production-Injection Strategies

Scenario	Development	Location of Injection	Deep of Injection	Production
S1	110 MW	Centered	Deep	Steam
S2	110 MW	Centered	Deep	Brine
S3	110 MW	Centered	Deep	50%Steam + 50%Brine
S4	110 MW	Centered	Deep	25%Steam + 75%Brine
S5	110 MW	Centered	Shallow	Steam
S6	110 MW	Centered	Shallow	Brine
S7	110 MW	Centered	Shallow	50%Steam + 50%Brine
S8	110 MW	Centered	Shallow	25%Steam + 75%Brine
S9	110 MW	Dispersal	Deep	Steam
S10	110 MW	Dispersal	Deep	Brine
S11	110 MW	Dispersal	Deep	50%Steam + 50%Brine
S12	110 MW	Dispersal	Deep	25%Steam + 75%Brine
S13	110 MW	Dispersal	Shallow	Steam
S14	110 MW	Dispersal	Shallow	Brine
S15	110 MW	Dispersal	Shallow	50%Steam + 50%Brine
S16	110 MW	Dispersal	Shallow	25%Steam + 75%Brine
S17	220 MW	Centered	Deep	Steam
S18	220 MW	Centered	Deep	Brine
S19	220 MW	Centered	Deep	50%Steam + 50%Brine
S20	220 MW	Centered	Deep	25%Steam + 75%Brine
S21	220 MW	Centered	Shallow	Steam
S22	220 MW	Centered	Shallow	Brine
S23	220 MW	Centered	Shallow	50%Steam + 50%Brine
S24	220 MW	Centered	Shallow	25%Steam + 75%Brine
S25	220 MW	Dispersal	Deep	Steam
S26	220 MW	Dispersal	Deep	Brine
S27	220 MW	Dispersal	Deep	50%Steam + 50%Brine
S28	220 MW	Dispersal	Deep	25%Steam + 75%Brine
S29	220 MW	Dispersal	Shallow	Steam
S30	220 MW	Dispersal	Shallow	Brine
S31	220 MW	Dispersal	Shallow	50%Steam + 50%Brine
S32	220 MW	Dispersal	Shallow	25%Steam + 75%Brine

reservoir, mass flow, and the steam cap expansion are observed to learn the change of reservoir characteristics *versus* production time.

Discussion

Study of Production-Injection Strategies for 110 MW

The constant flow rate method is used to see both the change of pressure and temperature. The changes in steam cap pressure for 110 MW, the results are $\Delta P_{steam\text{-}cap} > \Delta P_{combination} > \Delta P_{brine\text{-}reservoir}$. Contrary, if the change of pressure is viewed at the brine reservoir, $\Delta P_{steam\text{-}cap} < \Delta P_{combination} < \Delta P_{brine\text{-}reservoir}$.

The best production strategy is considered by a low decline rate of each strategy and was achieved by summing up every mass flow at each block. Figure 4 shows a decline rate for each production-injection strategy for 110 MW. Referring to the pressure drop and decline rate from the model, and the best production strategy is a combination of 25% from the steam cap and 75% from brine reservoir.

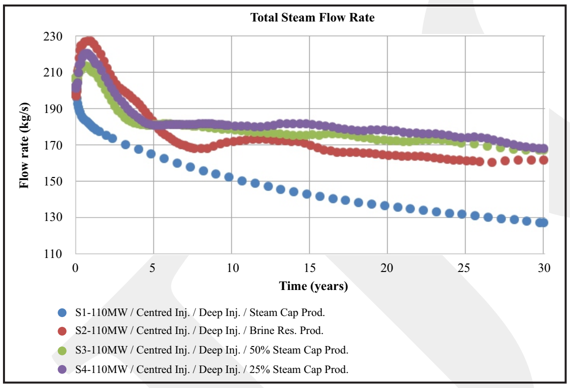

Figure 4. The decline rate for each production-injection strategy for 110 MW.

After the best production strategy was obtained, the next step was to choose the injection strategy. The best production strategy mentioned above was used for all of the injection strategies carried on. The simulation results show in Figure 5. Dispersed and deep injection generates a relatively lower pressure drop both in the steam cap and brine reservoir. This lower pressure drop is because the separated brine reinjection spread with well pad surrounding the production reservoir. Therefore, this strategy uniformly gives additional pressure for balancing the production induced by pressure drop and maintains the pressure drop at the lowest level possible. In comparison, the deep injection strategy improves a thermal recovery because both separated brine and steam condensate is injected at the deeper reservoir, which has a higher temperature and minimizes the cooling effect due to reinjected fluid back to the production reservoir. Figure 6 shows the best production-injection strategy for 110 MW, which is 25% of production from the steam cap and 75% from the brine reservoir paired with dispersed and deep injection.

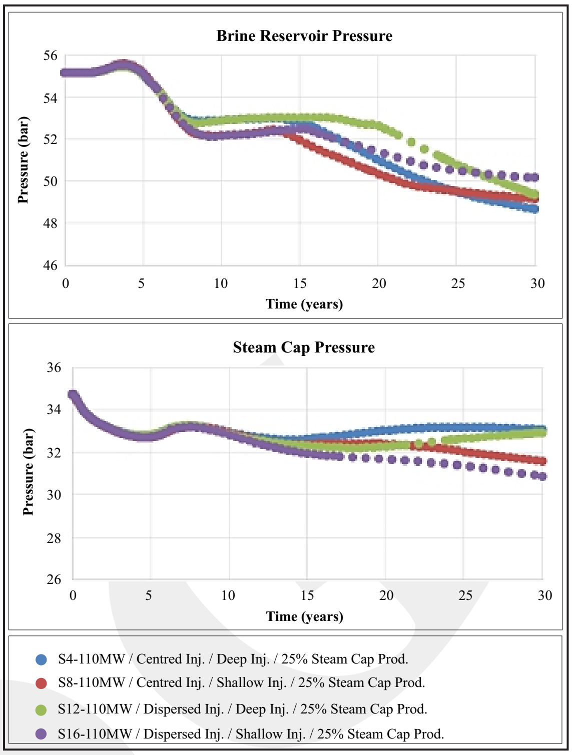

Figure 5. Pressure decline of a combination production 25% from steam cap (upper) and 75% brine reservoir with various injection (lower).

Study of Development 110 MW *vs.* 220 MW

The best production-injection strategy for 220 MW was achieved by using the same method as 110 MW. The change of pressure on the steam cap and brine reservoir shown in Figure 7.

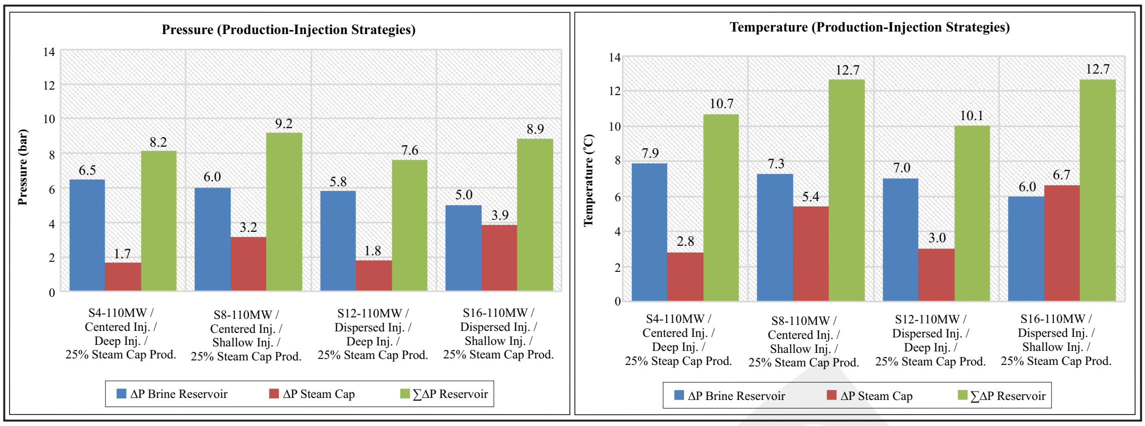

Figure 6. The pressure (top) and temperature (bottom) at production 25% steam cap and 75% brine reservoir for 110 MW.

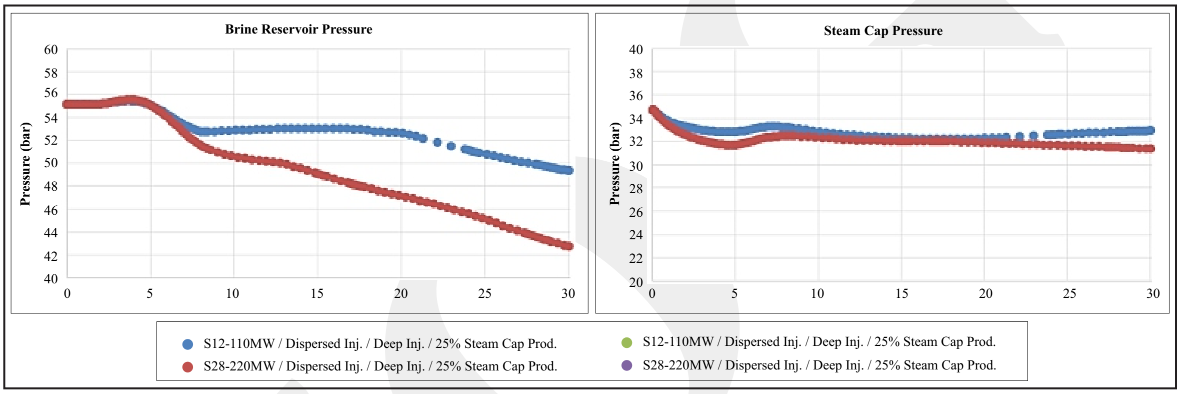

Figure 7. The changing of pressure for 110 MW *vs*. 220 MW, production 25% from steam cap and 75% brine reservoir paired with dispersed and deep injection (Pratama and Saptadji, 2017).

The 220 MW has a higher pressure drop than 110 MW in the steam cap and brine reservoir. After 10 years of exploitation time, stabilization pressure occurred at the steam cap for both 110 MW and 220 MW. Table 6 shows the magnitude order of decrease both pressure and temperature for 220 MW, which is almost twice that of 110 MW.

The 2D Isobar contour as a result of the simulation is presented in Figure 8. The steam cap pressure has almost no difference ($\Delta P_{110\,MW-220\,MW}$ = 1 bar) even though the amount of fluid production is twice. The pressure in the brine reservoir

Table 6. The comparisonof both pressure and temperature for 110 MW vs. 220 MW

Capacity	ΔP Brine Res (bar)	ΔT Brine Res (°C)	ΔP Steam Cap (bar)	ΔT Steam Cap (°C)
110 MWe	6	7	2	3
220 MWe	12	16	3	6

for 110 MW is still influenced by reinjection. Higher pressure occurred near the injection well by the return of fluid reinjection. It did not occur at 220 MW generation, as 800 kg/s of brine produced from the brine reservoir resulting in a uniform pressure drop in the whole of the brine reservoir, and it could not be overcome by 470 kg/s brine reinjection. Based on the analysis above, it can be concluded that the process of fluid filling pores or fractures in the reservoir is not as fast as the production.

The isothermal contour that has been affected by the fluid injection temperature is shown in Figure 9. Steam condensate (45°C) has a more significant impact on cooling in the reservoir than separated brine (180°C). Increasing the rate of injection has an impact on a broader uniform cooling area of the reservoir. Based on the analysis above, it can be concluded, the process of

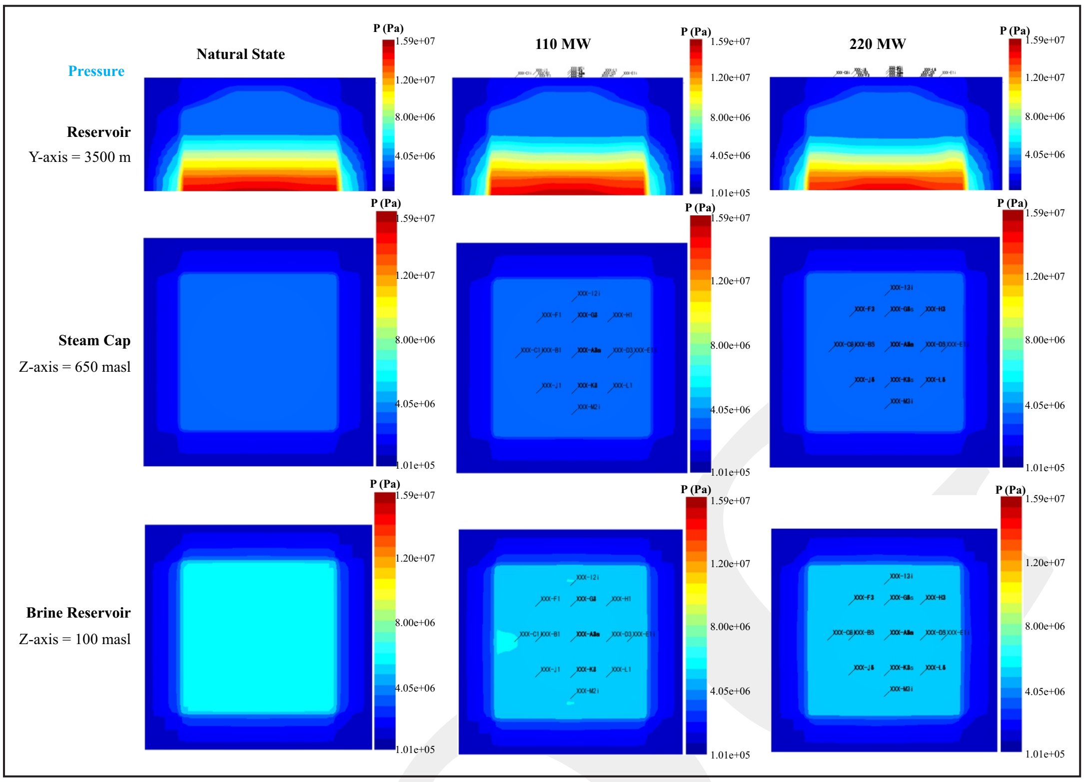

Figure 8. Profile of pressure between natural state, 110 MW, and 220 MW (Pratama and Saptadji, 2017).

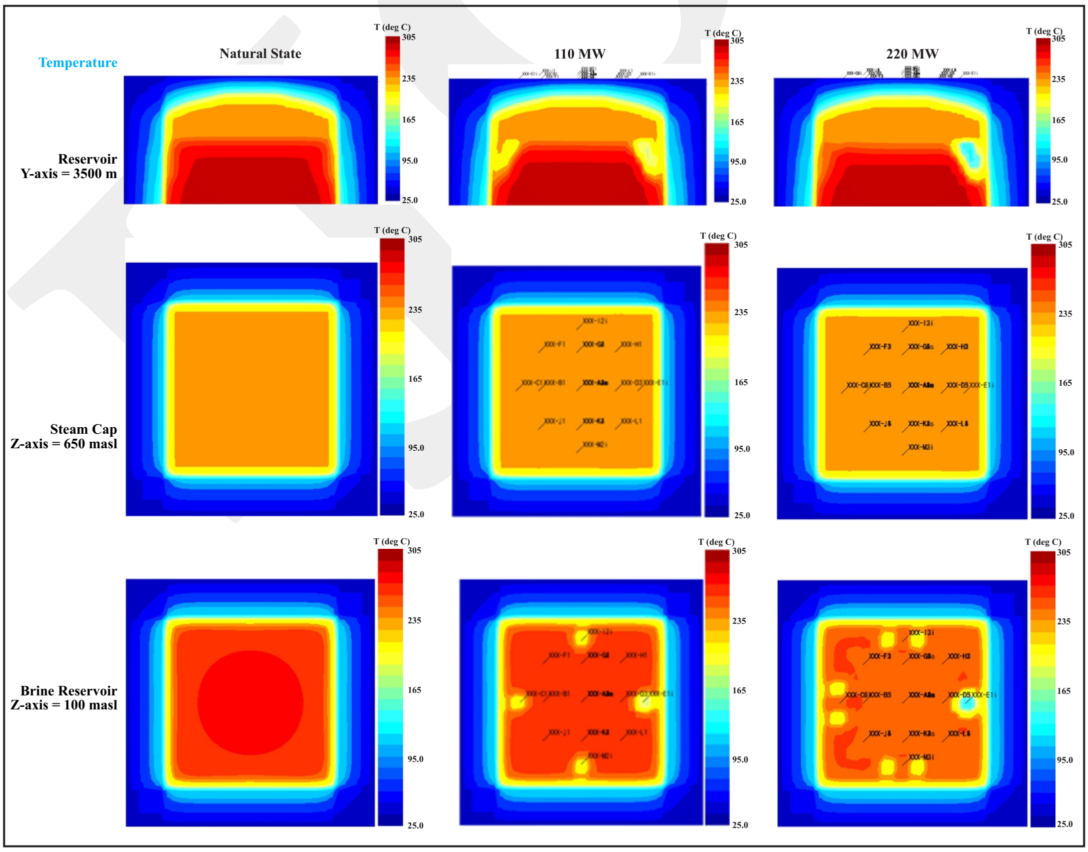

Figure 9. Profile of temperature between natural state, 110 MW, and 220 MW (Pratama and Saptadji, 2017).

heating fluids reinjection back into the reservoir is not as fast as the process of extracting heat from reservoir rock. A higher reinjection rate has an impact on a higher and broader cooling reservoir. A reinjection has an advantage in pressure support to reduce the effect of production induced by pressure drop but has a disadvantage at a thermal breakthrough in a partial area of the reservoir or an entire reservoir.

The increasing installed capacity to 220 MW will increase the reservoir boiling level, as shown in Figure 10. The boiling results in an increase and expansion of steam saturation in the steam cap and brine reservoir. A higher production rate from the brine reservoir will be accelerated by increasing steam saturation that fills reservoir rocks. The higher production rate will rapidly decline in pressure and increase the boiling; hence, the two-phase zone will expand.

In this study, both the steam cap and transition zone were expanding. Increasing installed power plant capacity twice, from 110 MW to 220 MW, will increase the thickening of steam cap and transition zonein the same order twice (Table 7).

Table 7. Comparison of the Expansion both of the Steam Cap and Transition Zone

Capacity	Thickening of Steam Cap		Thickening of a Transition Zone	
110 MWe	100 m	(15%)	300 m	(26%)
220 MWe	200 m	(30%)	600 m	(52%)

Sustainability

A decline in the geothermal reservoir mass flow rate occuring naturally as the injection rate is lower than the production rate. Thereby, it caused a pressure drop in the reservoir and impacted the decline in the flow rate. Therefore, to sustain the steam supply to a power plant, it is required to add make-up wells. There are three strategies of make-up wells; all make-up wells from the brine reservoir, all make-up wells from the steam cap, and the combination of them. The make-up wells combination is done by producing the make-up wells from a deep brine reservoir and steam cap with a specified period. The simulation of sustainable production has been done to get a production-injection strategy to provide the steam supply to the 220 MW power plant. As mentioned before,

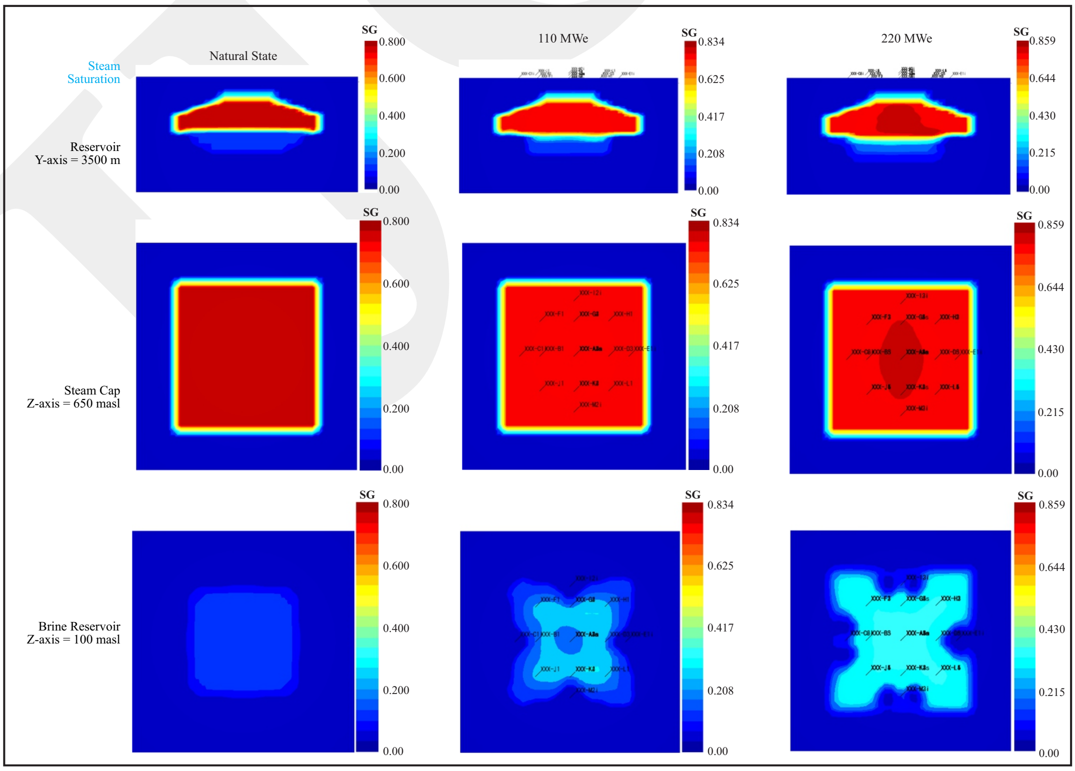

Figure 10. Profile of steam saturation between natural state, 110 MW, and 220 MW (Pratama and Saptadji, 2017.

the production strategies are 25% from the steam cap and 75% from the brine reservoir compared to 50% steam cap and 75% brine reservoir, and both of them paired with dispersed and deep injection strategy.

The graph presented in Figures 11, 12, and 13 show the campaign of make-up wells for the initial production stage and make-up wells to sustaining 220 MW. The outcome of scenarios for sustainable production, as mentioned above, production of 25% steam cap has the smallest number of make-up than the production of 50% steam cap. Additionally, the best make-up wells are all produced from the steam cap since it has the lowest number of well compared with the make-up well

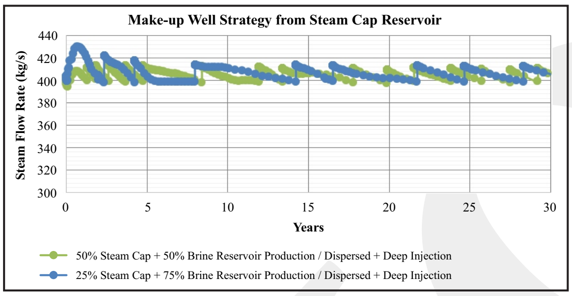

Figure 11. Strategy make-up wells from the steam cap (Pratama and Saptadji, 2017).

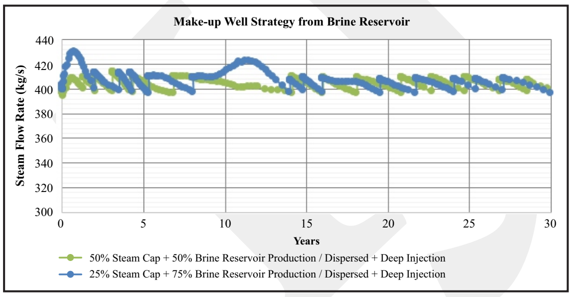

Figure 12. Strategy make-up wells of the brine reservoir (Pratama and Saptadji, 2017).

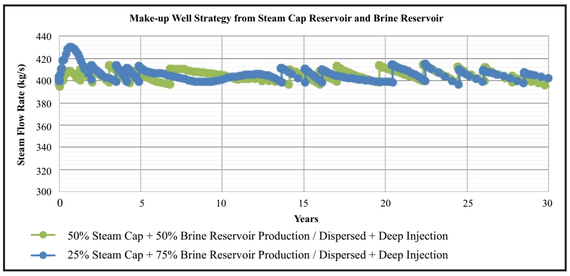

Figure 13. Strategy make-up wells of a combination from steam cap and brine reservoir (Pratama and Saptadji, 2017).

strategy produced either from brine reservoir only and the combination of steam and brine reservoir.

Tables 8 and 9 show the amount of make-up well for each production and injection strategy. The best scenario for sustaining production over 30 years of exploitation is make-up from steam cap; however, it is only visible for production from 25% of steam cap and 75% brine reservoir with dispersed and deep injection. It required 8 make-up wells compared to 15 make-up wells from initial production for the scenario of 50% steam cap and 50% brine reservoir with the same injection strategy. The greater production from brine reservoir is induced by the pressure drop in the deep region, consequently increasing the boiling process so that the dryness increased as a boiling area is either extended or thickened (Pratama and Saptadji 2017).

Table 8. Number of Make-up Well for each Production and Injection Strategies

Production Strategies	25% Steam Cap + 75% Brine reservoir	50% Steam Cap + 50% Brine reservoir
Make-Up Well from Steam Cap	9	15
Make-Up from Brine reservoir	12	13
Make-Up Well from Combination	12	14

Table 9. The total production wells and injection wells for each production and injection for 220 MW (after Pratama and Saptadji, 2017)

Production Well + Make-Up Well	Well from Steam Cap	Well from Brine reservoir	Total Well
25% Steam Cap + Make-Up from Steam Cap	15	20	35
50% Steam Cap + Make-Up from Steam Cap	27	13	40
25% Steam Cap + Make-Up from Brine reservoir	12	32	44
50% Steam Cap + Make-Up from Brine reservoir	15	26	41
25% Steam Cap + Make-Up from Steam Cap & Brine reservoir	12	26	38
50% Steam Cap + Make-Up from Steam Cap & Brine reservoir	19	20	39

In initial production, it is suggested to produce heat and mass from the deep reservoir or brine reservoir; hence, the boiling surge as the pressure in the brine reservoir dropped. It caused the increasing dryness in the boiling area as the boiling process turn out to be higher than the initial conditions. Therefore, the boiling area will be expanding and thickening. Nevertheless, the steam cap production becomes more economical as the steam from this area is supported by the higher boiling zone. Even though it seems favorable to produce steam from the steam cap, it must be balanced with reinjection strategies. The injection strategies should be optimized, so the pressure drop in the reservoir can be maintained as low as possible.

The decline in steam flow rate after the 30 years of the exploitation period is calculated by using the decline curves method based on Arps's empirical equation (Arps, 1945) and calculation method (Spivey, 1986; Aragón-Aguilar *et al.*, 2013) without making additional production from the make-up well. The aim is to determine the natural decline of reservoir performance in producing geothermal fluid.

$$q(t) = \frac{q_i}{(1+bD_i t)^{1/b}} \qquad (1)$$

Where q(t) is the current production rate, q_i is the initial production rate, t is the cumulative time since the start of production, D_i is nominal decline rate, b is decline exponent (exponential b=0, hyperbolic 0<b<1, and harmonic b=1).

The decline rate calculation using excel macros, and the calculation results are shown in Figure 14 and Table 10. The 6 make-up simulations conducted by the decline rate values range from 0.5% -1.3%; this is much better than the Kamojang decline rate 4.2% (Sanyal *et al*., 2000), Darajat decline rate 7.6% (Yamin *et al*., 2015). The lowest decline rate of 0.5% (harmonics) is obtained from the production strategy of 25% steam cap + 75% brine reservoir, dispersed + deep injection strategy, and a combination of make-up strategies (steam cap + brine reservoir). This strategy produces fluid from 38 wells (12 wells from the steam cap and 26 wells from the brine reservoir). This strategy is inversely proportional to the make-up strategy of steam cap wells and brine reservoir wells (same injection-production strategy), which results in a decline rate of 1.3% (hyperbolic) from 44 wells (12 wells from steam cap and 32 wells from brine reservoir). The higher the fluid produced from the brine reservoir, the higher the decline rate.

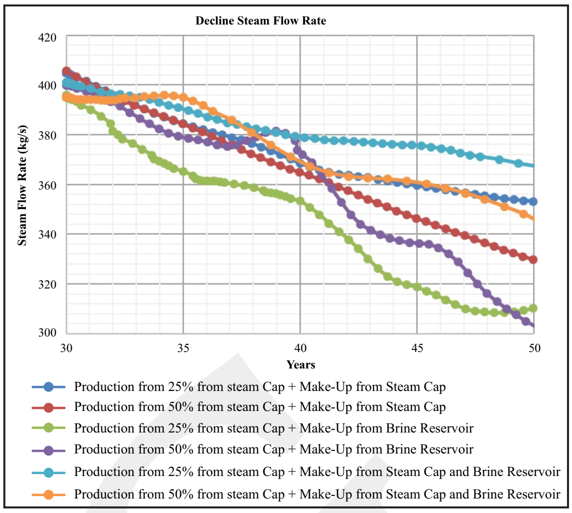

Figure 14. Decline curves after 30 years for injection-production strategies and make-up strategies.

Table 10. Results of the Decline Rate Calculation for Injection-Production Strategies and Make-up

Production - Injection	Make-up	Decline rate	Arps Exponent	Decline curves
25% Steam cap + 75% Brine reservoir, Dispersed + Deep injection	Steam cap	0.8%	1.0	Harmonic
50% Steam cap + 50% Brine reservoir, Dispersed + Deep injection	Steam cap	1.1%	0.3	Hyperbolic
25% Steam cap + 75% Brine reservoir, Dispersed + Deep injection	Brine reservoir	1.3%	0.2	Hyperbolic
50% Steam cap + 50% Brine reservoir, Dispersed + Deep injection	Brine reservoir	1.2%	0.0	Exponential
25% Steam cap + 75% Brine reservoir, Dispersed + Deep injection	Steam cap + Brine reservoir	0.5%	1.0	Harmonic
50% Steam cap + 50% Brine reservoir, Dispersed + Deep injection	Steam cap + Brine reservoir	0.7%	0.0	Exponential

The decline rate is undoubtedly the case for all the geothermal fields because the amount of fluid injected is lower than that produced reservoir fluids. To be able to produce reservoir fluid with a natural decline rate, it is necessary to do various appropriate stimulation methods. Such methods include acidizing, hydraulic fracturing, and work-over. This method is more economical and better than adding a make-up well, if tough to find well targeting, in the field with the capacity of a large PLTP (Kamojang, Awibengkok, Wayang Windu).

The make-up strategy analyzed is a study of a 25% steam cap + 75% brine reservoir strategy combined with a dispersed + deep injection strategy and a make-up strategy from a brine reservoir well for a 220 MW scenario. The strategy is based on the need for the number of make-up wells and the lowest steam rate decrease up to 50 years. Changes in pressure, temperature, and steam saturation of the steam cap and brine reservoir for 30 shown in Figures 8-10 and following for 20 years of reservoir shown in Figure 15.

The addition of make-up wells from the steam cap causes a local pressure drop, which is in the middle of the reservoir model and the shallow reservoir. This pressure drop is made possible by the drainage radius of the production well in the steam cap. If observed other than in these areas, the pressure drop does not occur significantly. The effect of injection on the reservoir pressure will be reduced because the magnitude of the pressure drop in the reservoir brine cannot be offset by additional pressure due to the reinjection fluid. In other words, the process of filling pores, the fractures in the reservoir rock, are not as fast as the extraction process.

Reducing the steam cap temperature may be due to the flow with a lower temperature into

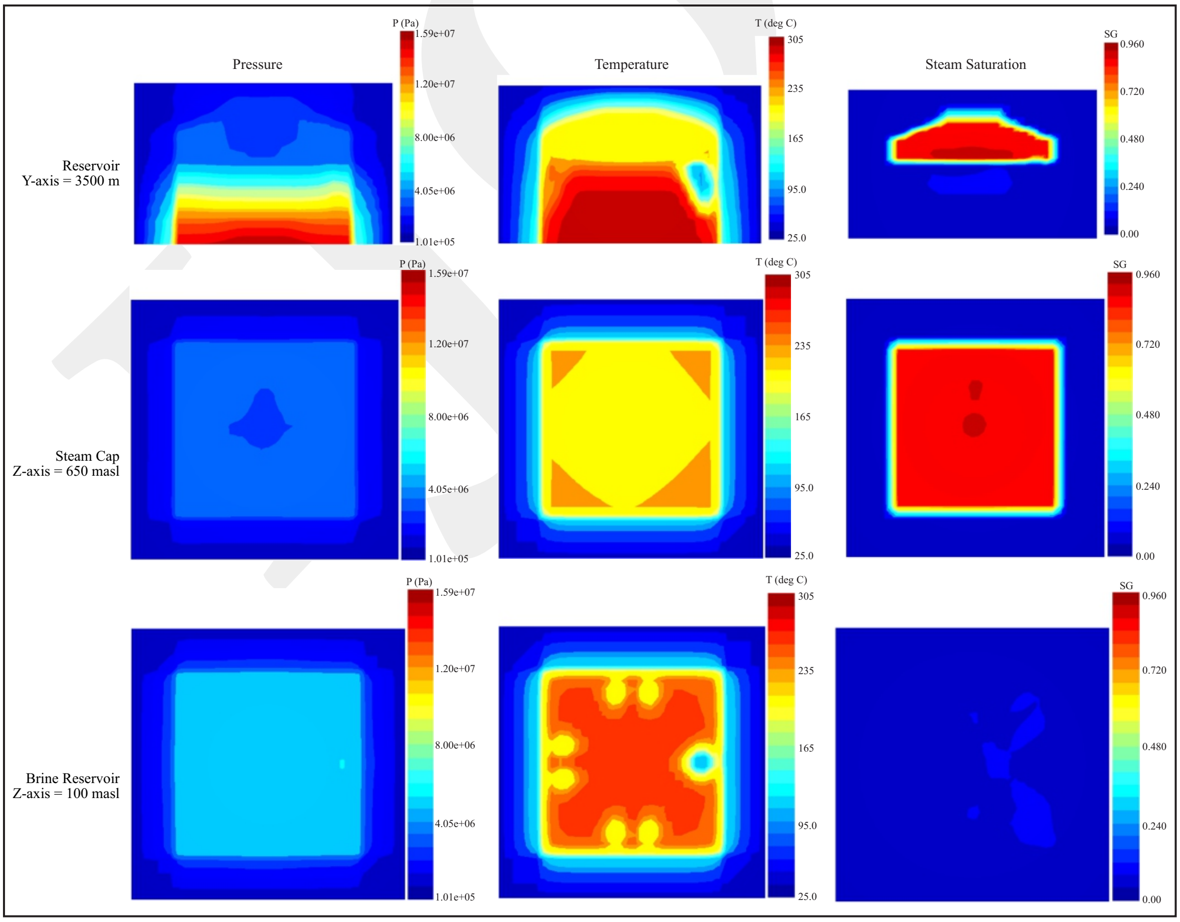

Figure 15. Profile of pressure, temperature, and steam saturation for 220 MW after 50-year production.

the shallow reservoir (steam cap). Therefore, the effect of the injection needs to be improved by injected brine and condensate should into deeper reservoirs.

In the central area of the steam cap formed up to 96% steam saturation, this could be the result of the steam formed from the boiling process in the brine reservoir joined and concentrated in the central steam cap. This result is inversely proportional to the changes that occur in the steam cap. Increased utilization time, impact on reducing steam saturation, and narrowing. The reservoir rock pores may have been refilled by the reinjection fluid even though the brine reservoir pressure has decreased (Figure 15 at the brine reservoir area).

Conclusions

1. The liquid-dominated reservoir model with a steam cap covering 13-23 km^2 and thickness of 500-1000 m, was successfully developed and validated with observation data and aligned with actual data.
2. The best production strategies for the numerical reservoir model with a reserve of 220 MW is a production with 25% of the steam cap and 75% of the brine reservoir and combined with dispersed and deep injection. It also applies to the lowest decline pressure and temperature in the reservoirs and achieved a sustainable production.
3. The steam cap thickening at 110 MW is 100 m, while for 220 MW generation is 200 m. The thickening in the transition zone at 110 MW is 300 m, while at 220 MW is 600 m.
4. The total wells for 30 years of production are 35 wells, with 15 wells from the steam cap and 20 wells from the brine reservoir. The lowest decline rate after the 30th year is a 50% steam cap + 50% brine reservoir strategy, dispersed + deep injection, and a combined make-up strategy with the decline rate 0.5%, Arps 1.0 exponent, harmonic decline curve.

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