Proceedings World Geothermal Congress 2015
Melbourne, Australia, 19-25 April 2015

Evaluation of Production Multilateral Well in Salak Geothermal Field, Indonesia

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Keywords: multilateral, formation stability, wellbore integrity, well deliverability, economic benefit

ABSTRACT

In late 2012, Chevron Geothermal and Power Operations Indonesia (GPO-I) drilled the first multilateral production well in the Salak Geothermal Field, Indonesia. Multilateral wells have the potential to reduce significantly the number of future make-up wells required to maintain full generation of 377 MWe at Salak. The goals of drilling a moderate- to high-inclination forked well were to reduce the cost of producing from the steam cap reservoir by penetrating more of the fracture network in the steam cap, and maximize deliverability of steam with low (<2.0 wt.%) non-condensable gas (NCG).

The most critical aspect of planning the multilateral well was selecting the interval for the unsupported open-hole junction for the forked leg. Geological and mechanical criteria were used to guide the selection process. To avoid potential production interference with the adjacent offset well, the trajectory of the original hole (OH) was turned 75° (Az. 278-353°; Incl. 55°) to achieve the planned trajectory. Sonic scanner (Modular Sonic Imaging Platform, MSIP) and gamma ray (GR) logs were run in the 17-½" hole to confirm competent formation at the interval selected for the open-hole junction. A bridge plug and retrievable whipstock were used for sidetracking the forked leg (FL) from the original hole. Both legs were completed with 10-¾" perforated liners; a 'scab liner' was installed across the milled window in the 13-⅜" casing to protect the integrity of the original hole (OH).

The deliverability of the well was calculated using Chevron's 'in-house' geothermal wellbore simulator, with a modified workflow to introduce the additional pressure loss in the upper section of the wellbore, and estimate the potential impact that either leg might act as a 'thief zone'. Based on the initial flow-test results, the well is expected to deliver 455 klb/hr (57.4 kg/s) of dry steam at commercial wellhead pressure. A full production flow-test cannot be conducted at this time due to limitation of the available surface facility capacity at the well pad. Drilling results and initial well evaluation have demonstrated the technical feasibility and economic benefit of multilateral wells at Salak. The better-than-expected results of the steam cap multilateral well indicate, however, that drilling two single-penetration wells would have delivered a higher steam rate. Ongoing work involves further evaluation of the additional pressure loss in the wellbore, and potential for increased interference between the OH and FL.

1. INTRODUCTION

The Salak (aka Awibengkok) geothermal field is located 60 km south of Jakarta, West Java, Indonesia on the southwestern flank of the Gunung Salak volcano (2,211 m ASL) (Figure 1). Currently, Salak is the largest producer of geothermal power (377 MWe) in Indonesia (Ibrahim et al., 2005). Exploration and initial development for commercial power generation was carried out by Union Oil of California (Unocal Geothermal Indonesia or UGI) through a Joint Operation Contract (JOC) with the Indonesian National Oil Company (Pertamina), and an Energy Sales Contract with Pertamina and the Indonesian National Power Company (PLN) for the sale of steam to PLN. The field has been managed by Chevron Geothermal Salak since August 2005, when Chevron acquired Unocal.

Commercial power generation at Salak began in 1994 with the installation of a 110 MWe plant (2 x 55 MWe or Units 1 and 2) operated by PLN (Murray et al., 1995). Production was increased to 330 MWe in 1997 with the addition of Unit 3, also operated by PLN and installed adjacent to Units 1 and 2, and Units 4, 5 and 6, operated by Chevron and installed at a separate location; Units 3, 4 5 and 6 are all 55 MWe plants (Soeparjadi et al., 1998). Generation was increased to 377 MWe in 2002.

Salak is a liquid-dominated geothermal system with a moderate- to high-temperature (464°-600°F / 240-316°C) fracture-controlled reservoir hosting benign and low to moderate non-condensable gas (NCG) fluids. The reservoir is contained within a sequence of volcanic rocks of predominantly andesitic to rhyodacitic composition with a basement of Miocene marine sedimentary rocks; both volcanic and sedimentary rocks are cut by igneous intrusions (Stimac et al., 2008). With a current installed capacity of 377 MWe and a proven reservoir area of about 18 km^2 (Figure 2), the field has a power density of about 20 MWe/km^2, despite all infield injection since the start of commercial production in 1994. To maintain full generation of 377 MWe the field has been developed through periodic drilling of make-up wells, and re-aligning injection. The most recent make-up well drilling campaign was in 2012-2013.

Chevron's previous experience with multilateral geothermal wells include a deep brine producing well at Bulalo, Philippines; an injection well at Tiwi, Philippines; and an injection well at Salak, Indonesia (Golla and Haas, 1998; Stimac et al., 2010). A multilateral completion for a shallow steam cap production well, however, has not been done before but offers a number of advantages over single well completions, most significantly by reducing the number of future make-up wells and well pads required, which in turn would minimize the operational and surface facilities 'foot-print' and reduce the overall generation cost ($/MWe).

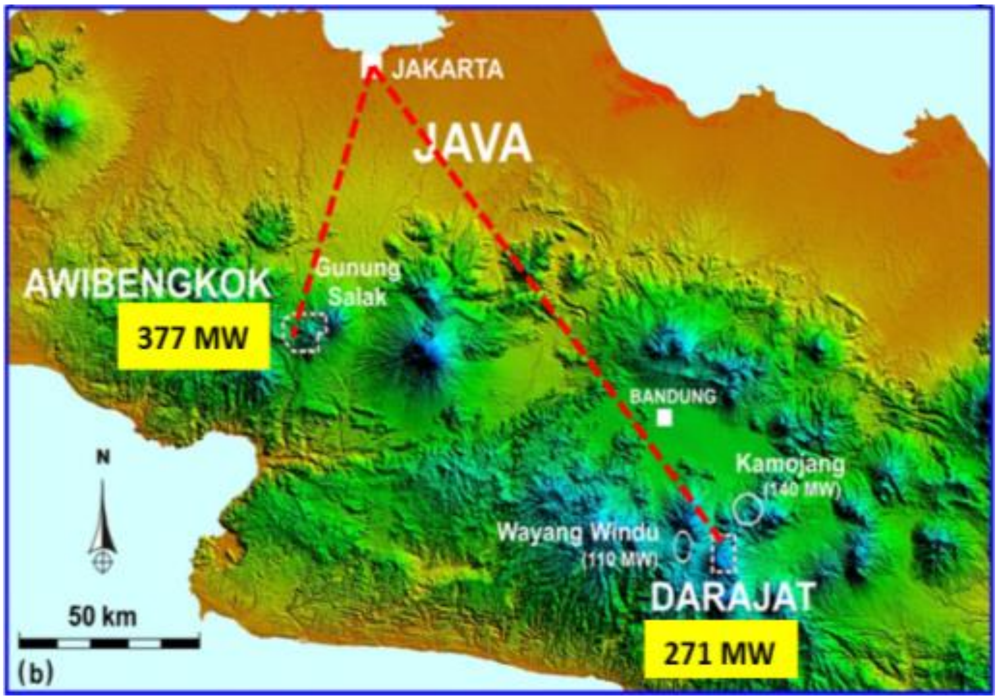


Figure 1: Map of West Java showing major cities and volcanic centers. Also shown are the Awibengkok/Salak and Darajat geothermal contract areas (dashed polygons) and other producing geothermal fields in the general area.

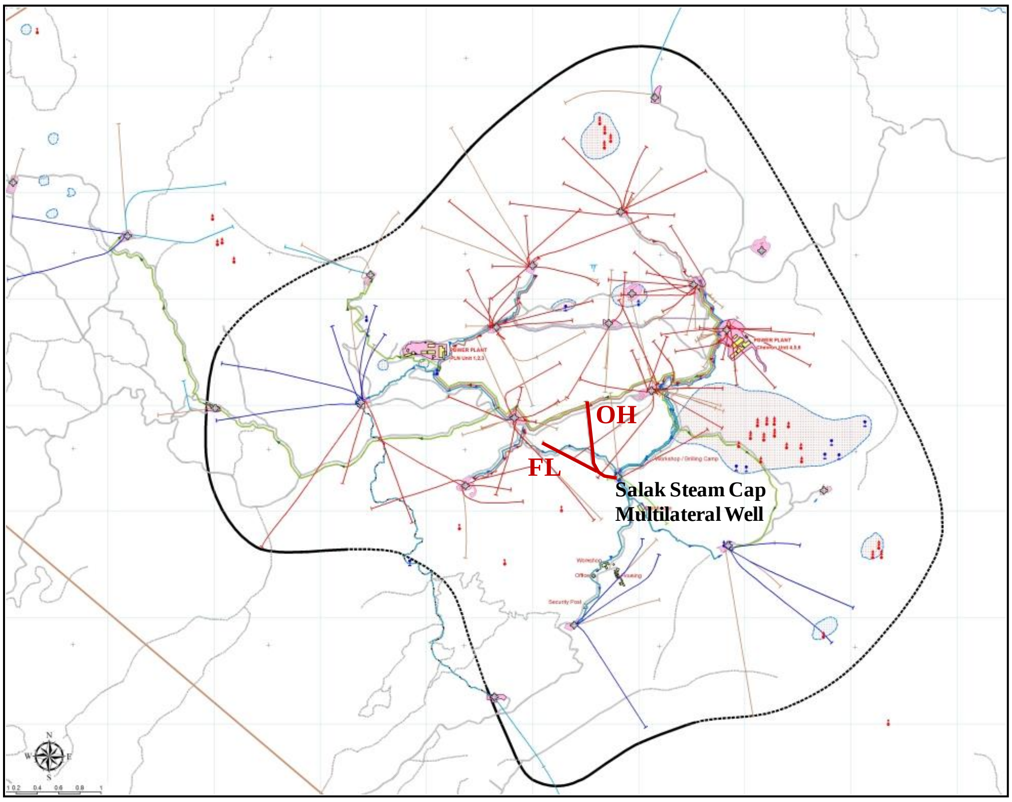


Figure 2: Map of Salak geothermal field showing outline of commercial reservoir boundary (black solid/dashed line), production (red) and injection wells (blue) and Salak steam cap multilateral well (bold red lines, OH and FL).

2. WELL PLANNING

The primary objectives of drilling a steam cap multilateral well at Salak were: (1) to demonstrate the technical feasibility of completing a moderate- to high-angle forked production well; (2) target production from the western area of the medium-pressure shallow steam cap; (3) intersect feed zones (identified from Pressure-Temperature-Spinner, PTS, surveys) in offset wells that were interpreted to be associated with fractures in brittle rock units (primarily lavas) within the Middle Andesite Formation and permeability possibly associated with NNE- to NE-trending and NNW-trending structures/lineaments (Figure 3); and (4) achieve an expected initial (P50 or Most Likely) well deliverability of about 320 klb/hr (40.4 kg/s) steam with low (<2.0 wt%) NCG.

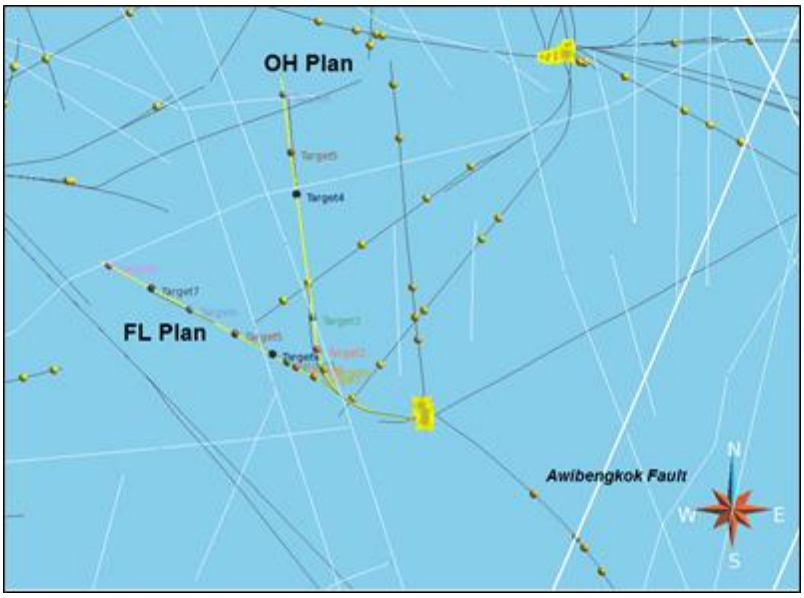


Figure 3: Plan view of the Salak steam cap multilateral well (yellow; planned trajectories of the original hole OH, and forked leg FL), and targets (colored dots); adjacent offset wells (blue) with identified feed zones (yellow dots). White lines are interpreted/inferred surface lineaments/structures.

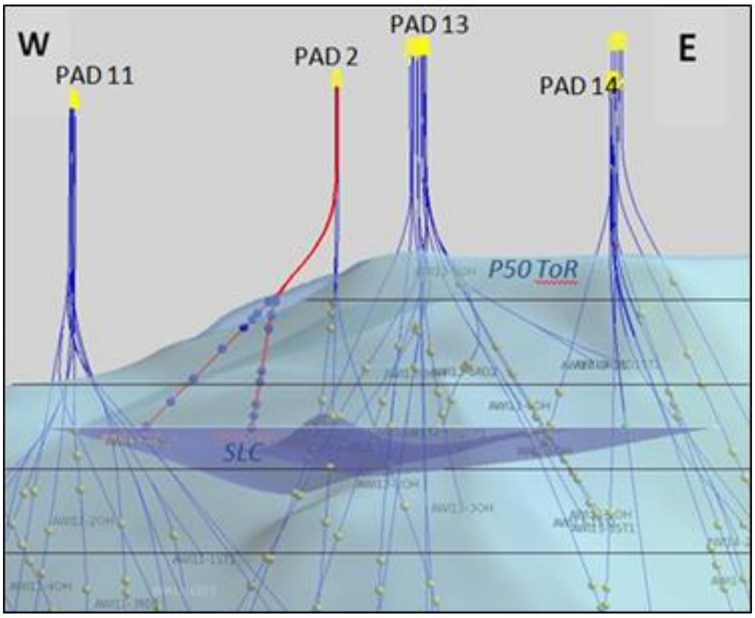


Figure 4: E-W profile showing trajectories of steam cap multilateral well (red) and offset wells (blue). Shaded surface labelled P50 ToR is interpreted top of the reservoir; SLC = steam-liquid contact.

To minimize production interference with the adjacent well, and between the original hole (OH) and the forked leg (FL), the trajectories of each leg were designed to achieve a separation distance between the targeted feed zones in each leg of about 1,000 ft. (305 m). The OH was designed with a turn of 75° (at Az. 278°-353°) to achieve the planned trajectory west of the closest offset well (Figure 3) while the FL was designed as a standard directional well. The closest separation distance between the shallower target feed zones was about 200-400 ft. (61-122 m), so there was still a high probability of interference between the two legs in the interval immediately below the production casing shoe of the OH and the shallowest target feed zone in the FL.

The three multilateral wells previously drilled by Chevron were completed with an ‘open-hole fork’ design by sidetracking the FL from the parent or original well by means of a retrievable whipstock. The FL was completed with slotted liner but a short, unsupported interval (i.e., no casing or liner) of open-hole remained at the junction to allow for expansion of the slotted liner as the well heats. The most critical aspect of planning and designing the multilateral well was selecting the interval for the unsupported open-hole junction. Lessons learned from the multilateral wells drilled previously in the Philippines and Salak were applied in designing the Salak steam cap multilateral well, in particular the geological and mechanical criteria for identifying and selecting a suitable interval for the unsupported open-hole junction, which should be within competent formation to minimize the risk of collapse of the open-hole junction during the life of the well. Another important consideration was the azimuth of the FL. A study by Sugiaman (2003) showed that the optimum azimuth for wellbore stability at Salak is about 114°/294°, which is the azimuth of the minimum horizontal stress, S_{hmin}.

The key differences between the Salak steam cap and the earlier multilateral wells were the larger casing size (13-⅜”) for milling the window for the open-hole junction, larger production hole size (12-¼”) for the FL, higher inclination of the OH (55°) and of the FL (49°) and the shallower planned total depths of each leg (about 5,500 ft. / 1,677 m). The target depths of the OH and FL were constrained by the depth of the steam-liquid contact in the vicinity of the well pad (Figure 4).

The following geological and mechanical criteria were used for selecting the interval for the unsupported open-hole junction for the FL of the steam cap multilateral well:

- Above the interpreted Most Likely (P50) Top of Reservoir (ToR);
- Single, continuous and competent rock unit with an Unconfined Compressive Strength (UCS) ≥10,000 psi;
  - Absence of weak formation(s), e.g., paleosols
  - No losses of circulation or permeable zones
  - Stable and ‘in-gauge’ hole (i.e., no wash-outs or hole enlargement)
  - At least 40 ft. (12 m) in length (to accommodate side-tracking, with competent rock above/below the milled window)
- Within a single joint of casing;
- Near the final depth of the 17-½” hole section (for better integrity of cemented casing); and
- Good cement bond between the casing and wellbore.

Using the above criteria, a review of data from offset wells at the same well pad identified a preliminary target interval for the open-hole junction for the FL at 2,250-2,400 ft. TVD (686-732 m. TVD). A caliper log from one of the offset wells showed ‘in-gauge’ hole (suggesting good wellbore stability) at the proposed target interval.

3. DRILLING PROCEDURE

The steam cap multilateral well was spudded on 22 September, 2012. To commence building angle, the OH was ‘nudged’ (by about 6°) from about 600 ft. (183 m) in the 26” hole section. After cementing 20” casing, the 17-½” hole was drilled with full returns to its planned depth, while turning the well 40° (Az. 318°) and building angle (Incl. 40°). Open hole sonic scanner (i.e. Modular Sonic Imaging Platform, MSIP) and gamma ray (GR) logs were run in the 17-½” section to confirm competent formation at the planned interval for the unsupported open-hole junction. Analysis of geological and drilling data and sonic and gamma ray logs identified a suitable interval for drilling the unsupported open-hole junction for the FL at 2,390-2,522 ft. (728-769 m):

- Above the interpreted P50 ToR at 2,500 ft. TVD (762 m. TVD);
- Single, continuous rock unit (i.e., moderate- to strongly-altered (propylitic; silicified) andesite lithic tuff);
- No paleosols or sloughing formation;
- No evidence for permeable zones (i.e., full returns to 17-½” hole section TD);
- Good wellbore stability (i.e., no ‘wash-outs’ or hole enlargement); and
- Estimated UCS >10,000 psi.

After completing both the MSIP and GR logging, the 13-⅜” production casing was cemented at 2,594 ft. (791 m). Directional work was completed in the 12-¼” hole (Az. 353°; Incl. 55°), which was drilled with intermittent returns from 2,649-4,063 ft. (807-1,238 m), then blind to a total depth of 5,314 ft. (1,620 m). The well was completed with a 10-¾” perforated liner, flushed with water and a short completion test was performed.

In preparation for drilling the FL, a bridge plug and retrievable whipstock were set inside the OH. A window was milled in the 13-⅜” casing at 2,413-2,431 ft. (736-741 m) within single joint of casing, with full returns (Figure 5). The FL was drilled (i.e., 12-¼” hole) as a standard directional well with 299° azimuth for optimum wellbore stability to a total depth of 5,062 ft. (1,543 m), and completed with a 10-¾” slotted liner. The FL was flushed with water and a short completion test was performed. The upper section of the 10-¾” perforated liner in the FL was then removed using a casing cutter. This left a short, unsupported interval of about 9 ft. (2.7 m.) of open-hole at the junction to allow for expansion of the perforated liner in the FL without protruding into and obstructing the OH. After cutting the slotted liner, the whipstock was retrieved and the bridge plug was drilled out and pushed to the bottom of the OH. To protect the OH from possible buckling (or collapse) at the milled 13-⅜” casing window, a 10-¾” perforated ‘scab liner’ was installed across the milled window. With this liner configuration, only the OH is accessible for further surveillance surveys. The rig was released on 17 October, 2012.

There were good indications of permeability when drilling the reservoir interval of both the OH and the FL. Mud circulation was lost and the OH was drilled blind below 4,063 ft. (1,238 m), while the FL similarly commenced blind drilling just 40 ft. (12 m) outside the milled window. Feed zones indicated by drilling breaks and fluid losses observed while drilling occur at similar elevations to steam entries identified in offset wells. Characterizing the geologic nature of the entries/permeability encountered in each leg, however, is difficult because data are limited (blind drilling); from offset well data, most entries occur within the Middle Andesite Formation composed of andesite lavas, breccias, lithic tuffs, possibly with thin interlayers of basaltic andesite lavas. From petrographic analysis, drill cuttings from 2,500 ft. (762 m) in the OH show extensive shearing and fault gouge, with wairakite. Deeper at 4000 ft. (1,219 m) are andesite lava flows with open spaces filled with epidote, quartz, chlorite, prehnite, titanite, adularia and hematite (indicating good permeability), and veins with adularia suggesting earlier boiling conditions. Also, some of the permeable entries may correlate with NNW-trending structures/lineaments. The shallower-than-expected depth of the first entry in the FL possibly indicates that the steam cap to the west of the well pad is thicker (i.e., ToR is shallower) than previously thought (Figure 6).

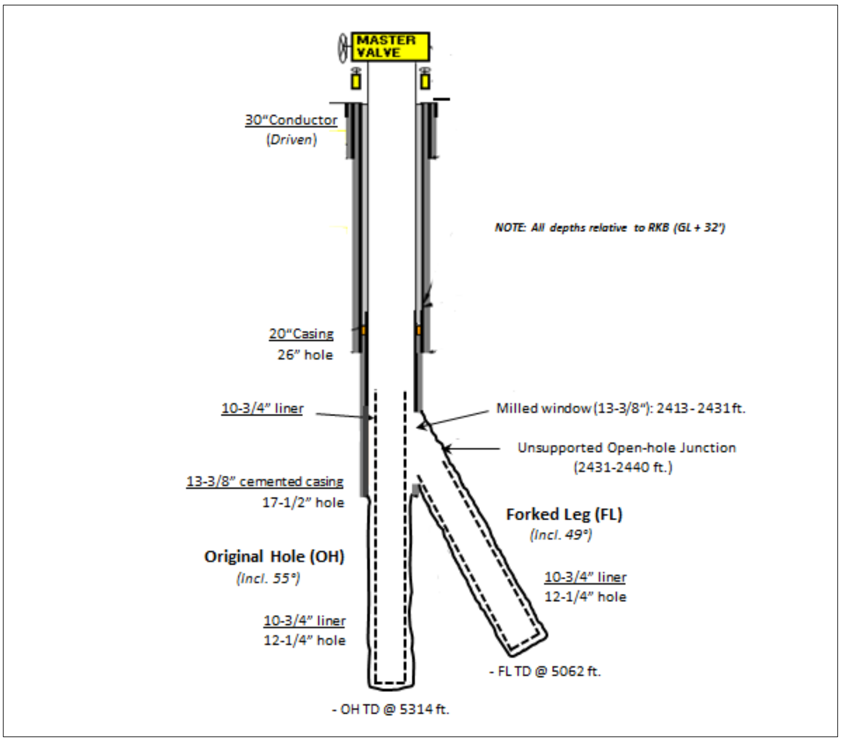


Figure 5: Well completion schematic of the Salak steam cap multilateral well.

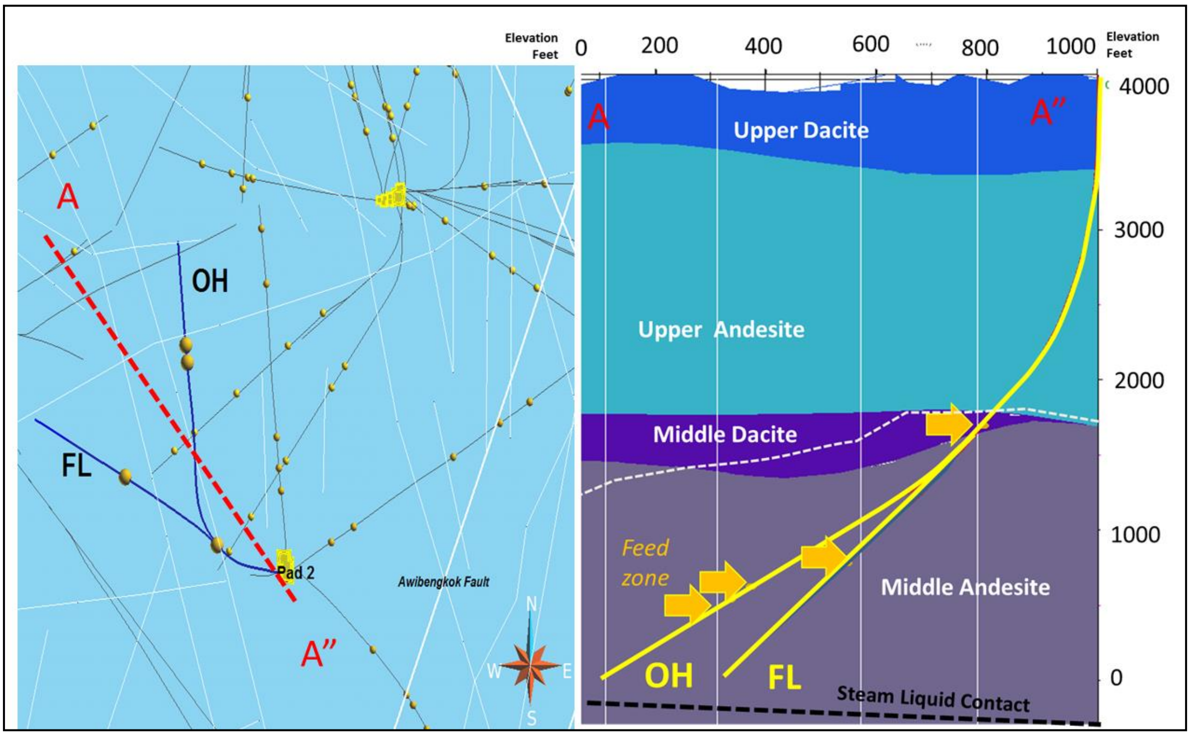


Figure 6: Plan view (left) and cross-section (right) of the Salak steam cap multilateral well. Profile A-A' (right; view from SW) shows the general stratigraphy, the OH and FL well trajectories (yellow) and identified feed zones (yellow arrows). Vertical white lines are inferred/interpreted subsurface traces of the mapped surface structures/lineaments. Also shown are the Most Likely ToR and the steam-liquid contact.

4. QUANTITATIVE ANALYSIS OF STEAM CAP MULTILATERAL WELL

4.1 Pre-Drilling Evaluation of Formation Pressure and Permeability

Salak is a liquid-dominated reservoir with initial production was from the liquid reservoir. Pressure decline in response to exploitation triggered the rapid development of a steam cap in the shallower reservoir especially in east Salak. Figure 7 shows the current pressures in the steam cap in east Salak where a strong pressure gradient is apparent. Moreover, the steam cap can be subdivided into high-, medium- and low-pressure regimes. Current interpretations indicate that the dominant controls in the distribution of steam cap pressure are the rock temperature and the temperature of the underlying boiling zone (Rohrs et al., 2005). Other controls include the thickness of the underlying boiling zone, geologic structure, and interference effects. Both the OH and FL targeted the medium-pressure steam cap region, where earlier drilled wells have an average shut-in wellhead pressure of 350 psia (24.1 bara).

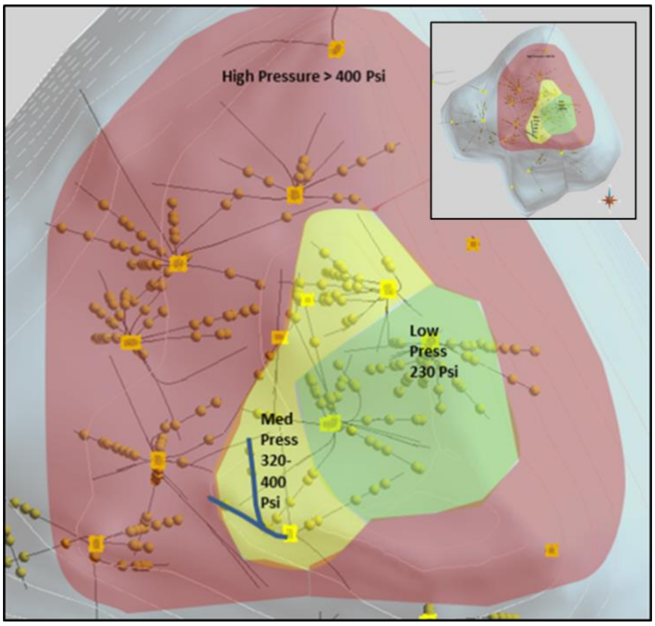


Figure 7: Map showing the high-, medium- and low-pressure regions of the shallow steam cap in east Salak. The steam cap multilateral well (bold black lines) targeted the medium-pressure steam cap region.

Besides formation pressure, information on expected Productivity Index (PI) is an important parameter when planning and designing new production make-up wells, including a multilateral well since the PI is linearly correlated to well production (Equation (1) in Appendix A). The estimated PI and geological information from surrounding wells and the Salak reservoir model was used to estimate the PI of potential feed zones targeted by the multilateral well. The PI is proportional to permeability-thickness (*kh*) as described in Equation (2). As there is no brine disposal facility at the well pad, it was important that both legs (OH + FL) are completed above the steam-liquid contact (SLC) hence the expected discharge enthalpy is the steam enthalpy of 1200 Btu/lb (2791 kJ/kg). A list of potential feed zones targeted by both the OH and FL, including the expected formation pressure, temperature and PI, is shown in Table 1.

Table 1: Elevation of well targets (OH + FL)

Original Hole (OH)					
No	Elevation (ft.sl)	P* (psia)	H (Btu/lb)	PI (klb/(hr.psi))	kh (mD-ft)
1.	1470	371.0	1200	1.103	73,855
2.	1337	371.7	1200	0.689	46,053
3.	1169	372.7	1200	0.561	37,414
4.	526	376.3	1200	0.245	16,201
5.	310	377.5	1200	0.124	8,176
6.	12	379.2	1200	0.081	5,320
Forked Leg (FL)					
No	Elevation (ft.sl)	P* (psia)	H (Btu/lb)	PI (klb/(hr.psi))	kh (mD-ft)
1.	1470	371.0	1200	0.832	55,709
2.	1337	371.7	1200	0.215	14,371
3.	1272	372.1	1200	0.095	6,344
4.	1168	372.7	1200	0.061	4,068
5.	914	374.1	1200	0.034	2,260
6.	571	376.0	1200	0.022	1,456
7.	291	377.6	1200	0.015	989
8.	-14	379.3	1200	0.011	722

Notes: P, H, PI and kh are reservoir pressure, flowing enthalpy, productivity index and permeability thickness, respectively. Both the OH and FL targeted the medium- to high-permeability area of the steam cap reservoir with total kh of 272,938 mD-ft.*

4.2 Pre-Drilling Calculation of Well Deliverability

The information in Table 1 was used to predict the initial well deliverability of the steam cap multilateral well using GEOFLOW, Chevron's 'in-house' geothermal wellbore simulator. GEOFLOW calculates the expected well deliverability of a proposed well by considering the well geometry, elevation, estimated PIs, pressure and enthalpy of the feed zones and the "assigned" wellhead pressure (based on surface operating conditions).

Using a modified workflow for GEOFLOW, a wellbore hydraulic model of a multilateral well was constructed that involved a two-step calculation for predicting well deliverability. The first step involved simulating the deliverability of each individual leg from the bottom of the well up to the junction point The second step involved simulating the combined deliverability of both OH and FL from the junction point up to the wellhead. Figure 8 shows the deliverability curves at the wellhead for each leg, as well as the combined deliverability and estimated deliverability based on an operating wellhead pressure of 150 psia. Wellbore modeling indicated that the estimated initial combined steam rate of the OH and FL is 320 klb/hr. / 40.4 kg/s (or 19 MWe).

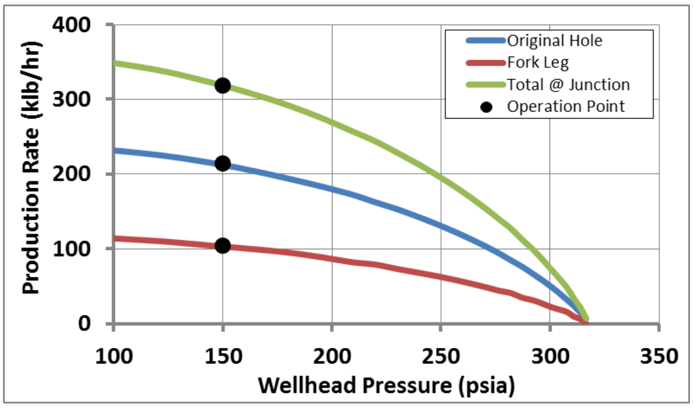


Figure 8: Estimated deliverability curves for original hole and forked leg, and combined total deliverability at the wellhead, which shows higher contribution from the original hole.

4.3 Post-Drilling Evaluation

An injection test was conducted immediately following the completion of each leg. About 624 klb/hr (78.7 kg/s) of power plant condensate was injected into the well but was insufficient to completely quench all the feed zones, which provide early indication that the well is a good producer. Figure 9 shows the Pressure and Temperature (PT) profiles for each leg under water injection. A pronounced step-increase in temperature can be seen in the profiles for each leg indicating inflow of steam from the reservoir during the injection PT survey. Injection Pressure-Temperature-Spinner (PTS) data has identified that the major feed zone in the OH is at elevation 627 ft.sl (4,200 ft. / 1280 m) while the major feed zones in the FL are at elevation 1711 ft.sl (2,450 ft. / 747 m) and 825 ft.sl (3,750 ft. / 1143 m). The first feed zone in the FL is considerably shallower than the first permeable entry in the OH.

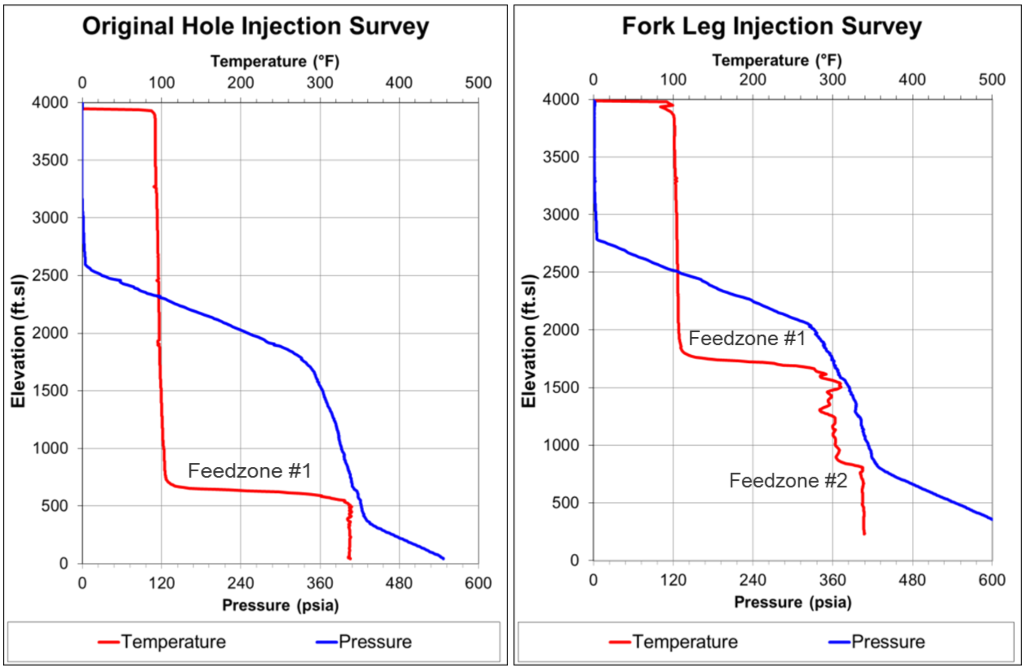


Figure 9: Charts showing the Injection PT profiles (from the Completion Test) of the Original Hole (left) and Forked Leg (right). The two-phase zone is indicated at the major feed zone where inflow of steam from the reservoir boils the injected water.

Recently, a flow-test through a 3" stimulation line at the well pad was conducted. Due to the liner configuration, only the OH was accessible for re-entry by wireline tools. The well was able to deliver 57 kph (7.2 kg/s) of steam at a wellhead pressure of 379 psia

(26.1 bara). This is much above the minimum requirement of commercial wellhead pressure of 150 psia. Figure 10 shows the interpretation of the flowing Pressure-Temperature-Spinner (PTS) survey which indicates a higher contribution from the FL at the junction at 2,400 ft. (732 m). This is contrary to what was expected when planning the well wherein the contribution from the OH was expected to be higher than from the FL. The major feed zone identified by the flowing PTS survey at about 4,200 ft. (1280 m) in the OH is consistent with injection test interpretation. Another part of well analysis is to define formation pressure especially at feed zone locations. A vapor static pressure is added to the measured wellhead pressure to estimate pressure at feed zone location. Actual reservoir pressure is slightly higher than estimated and both legs have intersected the same pressure regime (medium- to high-pressure regime) in the steam cap reservoir.

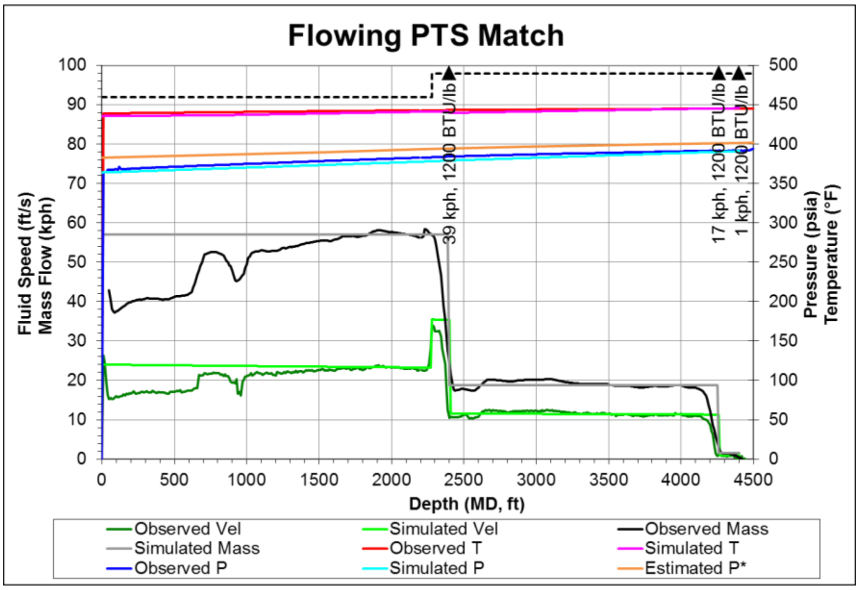


Figure 10: Chart showing results of the flowing PTS survey with pressure, temperature, mass rate and velocity matches. Increase of mass flow and velocity at the junction point at 2,400 ft. (732 m) indicates major steam contribution from the FL (about 69% of total well deliverability or 39 kph of steam). Also shown is a plot of the estimated reservoir pressure (P*).

Since the flow rate of each feed zone and the estimated reservoir pressure (*P**) are known, actual productivity indices (PIs) and permeability thickness (*kh*) can be calculated using Equations (1) and (6) in Appendix A. The total *kh* of the steam cap multilateral well is 365,053 mD-ft. with the OH and FL having *kh* of 123,646 mD-ft and 241,407 mD-ft., respectively. The FL intersected higher permeability in the reservoir than the original well (OH), which again is contrary to what was estimated during well planning (Table 2). In general, the actual total permeability thickness of the multilateral well is about 25% higher than expected.

Table 2: Feed zone locations zones intersected by OH and FL

Original Hole (OH)						
No	Depth (ft.MD)	Elevation (ft.sl)	P* (psia)	H (Btu/lb)	PI (klb/(hr.psi))	kh (mD-ft)
1.	4200	627	401	1200	1.84	114,940
2.	4400	523	402	1200	0.14	8,706
Forked Leg (FL)						
No	Depth (ft.MD)	Elevation (ft.sl)	P* (psia)	H (Btu/lb)	PI (klb/(hr.psi))	kh (mD-ft)
1.	> 2400	>1749	394	1200	3.81	241,407

One disadvantage of current multilateral completion is the inability to access both legs after well completion. For this particular case, the logging tool including PTS tool was only able to access the OH and unable to access the FL. Well deliverability was then determined using simple wellbore simulation using a unified feed zone approach at "centroid" depth (Acuña, 2010; Grant and Bixley, 2011). This approximation is applicable for dry steam wells only and treated all the feed zones in the FL into a single feed zone. As the contribution of the FL feed zone(s) is unknown, it was assumed that the "centroid" point is at the junction depth, which is close to the major feed zone in the FL anyway. Based on the actual well deliverability curve shown in Figure 11a, the initial well deliverability of the multilateral well was 455 klb/hr / 57.4 kg/s (27 MWe) of dry steam at commercial wellhead pressure (i.e., 150 psia). This steam deliverability is 42% above the target steam rate (i.e., 320 klb/hr.) hence a high-performance well. The initial steam contributions from the OH and FL legs are 142 klb/hr / 17.9 kg/s (31%) and 313 klb/hr / 39.5 kg/s (69%), respectively, which are also consistent with the interpretation of the flowing PTS survey.

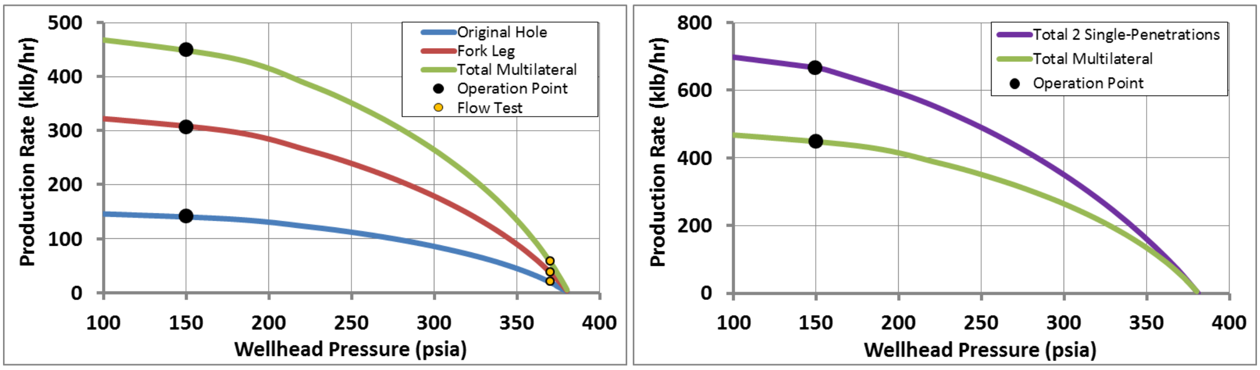


Figure 11: (a) Left - Actual well deliverability of multilateral well inferred from flowing PTS analysis using simple wellbore simulation and the unified feed zone approach. Steam contribution from FL is higher than OH which is also consistent with the total kh of the FL; (b) Right - Lower multilateral well deliverability compared to two single-penetration wells due to additional pressure loss (bottle-neck).

Table 3 shows the relative benefits of drilling a multilateral well against single-penetration well(s) using simple economic analysis based on generation cost index (i.e., %/MWe) which is equivalent to actual generation cost ($/MWe); lower generation cost ($/MWe) is preferable. Total steam production from multilateral completion is 32% lower than that of two single-penetration wells. This is mainly due to the additional pressure loss in the upper section of the wellbore in the multilateral well. However, drilling cost of multilateral completion is eventually lower than that of two single-penetrations since the multilateral completion can save 46 % of total drilling cost. Assumption taken for drilling cost for two single-penetration wells is double the cost of drilling the original hole (OH).

Table 3: Simple economic analysis of multilateral vs. single-penetration well(s)

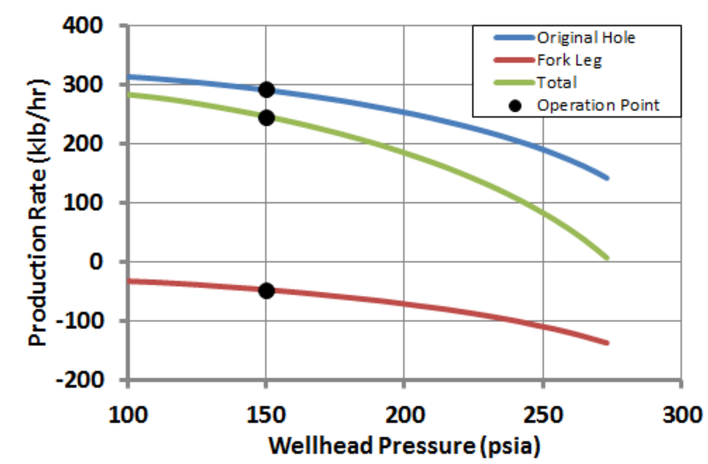
Well Type	Production Rate (klb/hr)			Generation Rate (MW)	Drilling Cost Percentage (%)	Generation Cost (%/MWe)
	OH	FL	Total			
1 Single-Penetration	261	N/A	261	15.5	100	6.5
Multilateral	142	313	455	27.1	154	5.7
2 Single-Penetration	261	406	667	39.7	200	5.0

The successful results of the multilateral well confirm the technical and economic feasibility of drilling a steam cap multilateral well at Salak. A multilateral well has more favorable $/MWe generation cost compared with a single-penetration well drilled in the same program. Drilling two single-penetration wells, however, provides the lowest $/MWe generation cost as these wells potentially yield higher incremental production compared to a multilateral well. For the steam cap multilateral well, the effect of pressure loss in the wellbore becomes more significant (thus limiting deliverability and consequently reducing the economic value) because both the OH and FL intersected high permeability in the reservoir. Thus, drilling two separate single-penetration wells would have delivered a higher steam rate. This conclusion, however, does not take into account several subsurface and surface uncertainties (e.g., production interference, subsurface heterogeneity, surface footprint, etc.) which could lead to different outcomes.

5. DOWNSIDE ASPECTS OF MULTILATERAL COMPLETIONS

The base-business development scenario at Salak is to maintain full generation of 377 MWe for the longest period possible. Drilling single-penetration make-up wells has been the primary strategy to support this scenario. However, the initial steam production of new make-up wells decreases with time due to pressure and temperature decline in the reservoir while drilling costs keep increasing. At some point in the future, drilling conventional single-penetration make-up wells will not be a viable option. Drilling multilateral make-up wells can reduce drilling costs and satisfy the steam supply requirements. Despite the potential benefits, however, there are some downside aspects of multilateral completions:

- Potential failure or collapse (at a later time) of the unsupported open-hole junction.
- Additional pressure loss (bottle-neck) in the production casing due to the combined steam flow from the OH and FL.
- Selective access to either the OH or FL for wireline logging and other well surveillance activities.
- Potential to create a 'thief zone' whereby steam from one leg flows to the other leg. This can occur if the two legs intersect different pressure regimes in the steam cap. Figure 12 shows the results of wellbore simulation using data from Table 1 where the FL encounters a low-pressure regime while the OH encounters a medium-pressure region of the steam cap. With a pressure differential of 70 psi / 4.8 bar, the FL will act as a 'thief zone' and take about 47 klb/hr / 5.9 kg/s of steam from the OH, and eventually reduce total steam production at the wellhead.



Production Rate (klb/hr)		
OH	FL	Total
293	-47	246

Figure 12: Chart showing the effect of the OH and FL penetrating different pressure regimes in the steam cap. The leg with the lower pressure will act as a 'thief zone'.

- Production interference between legs. Higher interference is expected in a multilateral well due to potentially shorter separation distance between the feed zones in each leg. Even though the potential production interference can be included in the economic evaluation of a multilateral completion, actual data from a flow-test are required to better quantify the effect of interference on steam production. At the time this paper was written, a full production flow-test of the steam cap multilateral well at Salak has not been conducted due to limitation of surface facility capacity at the well pad.

6. CONCLUSIONS

Following earlier successes in drilling multilateral injection and brine production wells, the first multilateral production well at Salak was drilled in late 2012. The successful drilling operations and better-than-expected steam deliverability demonstrate that multilateral technology can be applied for future steam cap make-up wells at Salak. Careful selection of the interval for the unsupported open-hole junction for the forked leg of the well was critical to the success of the project. Installing a 'scab liner' across the milled window in the 13-⅜" casing will help to maintain the integrity of the original hole. The favorable results confirm that the interval of the medium-pressure steam cap is larger (thicker) and extends further to the west than previously thought.

Construction of a wellbore hydraulic model of a multilateral well required modification of the current workflow for wellbore simulation. Actual data from injection tests and a brief flow-test were used to calibrate the wellbore simulation and validate the results. Both the OH and FL encountered higher-than-expected permeability in the shallow steam cap reservoir thus pressure loss in the wellbore was significant and limited the deliverability of the well. Drilling two separate single-penetration wells would have delivered a higher steam rate, and more favorable $/MWe generation cost. Based on recent analyses, the actual well deliverability of the well is 42% above the P50 initial expected steam rate, with higher contribution from the FL. A full production flow-test is required to fully characterize the well and to evaluate further some downside aspects of multilateral completions.

7. ACKNOWLEDGEMENTS

We thank Chevron Geothermal Salak for supporting this project and granting permission to publish this paper. Planning of the well was aided by many individuals, in particular, Dimas Widianto, Sintar Purba and Marino Baroek. We also thank the rig crews and support personnel of Apexindo Rig #4 and all the Business Partners who contributed to the successful drilling operations.

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APPENDIX A

Productivity Index (*PI*) is defined as mass production rate available per unit pressure drawdown, which can be expressed as follows:

$$PI = \frac{\dot{m}_f}{\Delta P} \tag{1}$$

Where $\Delta P = (P^{*}-P_{wf})$

Here *PI* is productivity index in klb/(psi.hr), $\dot{m}_f$ is mass flow rate in klb/hr; P^* is the formation pressure in psia and P_{wf} is wellbore flowing pressure in psia.

Using assumption of radial flow and porous medium model for single phase of steam, PI can be written as follows

$$PI = \frac{2\pi kh \times C}{\ln\left(\frac{r_e}{r_w}\right) + S - 0.5}\left(\frac{MOB_s}{ECF}\right) \tag{2}$$

Where *kh* is permeability thickness in *mD-ft*; r_e is drainage radius in *m*; r_w is wellbore radius in *m*, *S* is skin factor (dimensionless) and C is conversion factor. Here it is assumed that r_e is 500 *m* (1640.4 *ft*) and r_w is 0.108 *m* (4.25").

MOB_s is steam mobility which refers to inverse of viscosity kinematic (ν_T),

$$MOB_s = \frac{1}{\nu_T} = \frac{\rho_s}{\mu_s} \tag{3}$$

Where ρ_s is the steam density in lb/ft^3 and μ_s is steam dynamic viscosity in centipoise. Meanwhile ECF (Enthalpy Correction Factor) comes from solving energy conservation equation rather than mass conservation for radial flow.

$$ECF = \frac{1}{H}\frac{\partial(\rho H)}{\partial \rho} = 1 + \frac{\rho}{H}\frac{\partial H}{\partial \rho} \tag{4}$$

For steam phase,

$$ECF \approx 94.68\frac{p^{*0.244}}{H} \tag{5}$$

Where *H* is the flowing enthalpy in Btu/lb. Rearranging (1) and (2) gives

$$kh = \frac{\ln\left(\frac{r_e}{r_w}\right) + S - 0.5}{1.65674 \times 10^{-6}}\left(\frac{ECF}{MOB_s}\right)\left(\frac{\dot{m}_f}{\Delta P}\right) \tag{6}$$

APPENDIX B

Combining both samples from Awibengkok and Bulalo, the UCS-density correlation can be expressed by the following equation:

$$UCS = 70.821 \ \exp(2.2501 * \rho) \tag{7}$$

Where UCS is unconfined compressive pressure in psi and ρ is density in g/cc.