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

Potential Utilization of Idle Wells in Salak Geothermal Field, Indonesia

Riza G. Pasikki[1], Roman Sta Maria[2], Fathan Abdurachman[2], Colin Peters[2]

[1]Chevron GRG, 6750 Ayala Avenue, Makati, Manila 1226, Philippines

[2]Chevron Geothermal Indonesia, Sentral Senayan Tower-2, Jl Asia Afrika No 8, Jakarta 10270, Indonesia

E-mail address: rizagp@chevron.com, rsju@chevron.com, fbko@chevron.com, cwpe@chevron.com

Keywords: Salak, Reservoir Simulation, Low Pressure Steam, Weak Well, Idle Well, Modular Power Plant

ABSTRACT

Commercial operation of Salak Geothermal field was started in February 1994 when the first two units (Unit 1 and 2) totaling 110 MW were commissioned by the Indonesian utility company (PLN) to exploit the western side of the field. After exploring the eastern part of the field, four new units (Unit 3 operated by PLN and Units 4 - 6 operated by Chevron) were put on line in late 1997 that increased the total capacity of the field to 330 MW. Generation was further increased to 377 MW in 2002. Due to natural decline, periodic infill drilling has become the primary tool to meet steam supply demand for maintaining the 110 – 377 MW generation capacities. Currently, there are two groups of idle wells at Salak which are not supplying steam to existing power plants. The first group is weak wells which are not capable of producing steam at commercial wellhead pressure. Those weak wells can only produce steam at lower wellhead pressure and could therefore potentially be used to supply low-pressure (LP) steam. Two cases are being evaluated to assess potential utilization of weak wells:

- Use LP Steam to displace high-pressure steam on turbine Unit 4, 5 and 6 to maintain current generation. Currently, 1,010 kilo-pound per hour (kph) of high-pressure (HP) steam is delivered to the 1st stage of turbine, at pressure of 88 psia, to generate 65.6 MW. Early evaluation suggests that 250 kph of LP steam supplied to 6th stage of turbine, at pressure of 35 psia, could replace 120 kph of HP steam. This will eventually reduce generation cost through reduction of drilling make-up wells.

- Use LP Steam to increase generation from existing turbine to 70 MW by combining high pressure and low pressure steam.

The second group includes wells that were drilled for reservoir delineation and have commercial production but are in remote locations. Those wells are relatively far from the existing power plants and eventually increase hook-up costs. Availability of small power generation has opened up the alternative of producing those idle wells and adding electricity generation from Salak field.

The goals of this study include evaluating reservoir responses to change of production strategies, appraising the feasibility to modify operations on existing turbines, assessing technologies on small power generation and eventually to identify if realization of cases above could meet economic thresholds and deliver the necessary return on investment. This paper describes the planned work process and results from preliminary studies on reservoir processes and surface facility design options.

1. INTRODUCTION

On the basis of installed generation capacity, Salak is the largest geothermal field in Indonesia and the sixth largest in the world. Commercial operations started in February 1994 with the first two units totaling 110 MW and operated by the Indonesian utility company (PLN). After exploring the eastern part of the field, new units (Units 4, 5 and 6) operated by Chevron, were put on line in late 1997. At the time the units were operated at their guarantee point of 55 MW per unit bringing the total output of the Salak geothermal field up to 330 MW. New contract terms were negotiated with the Indonesian Government in 2002 which allowed Chevron to take advantage of the additional capacity of the existing units and increase the generation from the Salak field to 377 MW, with 180 MW supplied by Units 1, 2 and 3 and 197 MW from Units 4, 5 and 6. The plants have been operating in this configuration ever since. The original design of the Units 4, 5 and 6 power plant included four operating scenarios:

1) Case 1: Guarantee (55 MW)

2) Case 2: Normal (59.5 MW)

3) Case 3: High Pressure (65.6 MW)

4) Case 4: Future (70 MW)

The turbines at Units 4, 5 and 6 are single cylinder, double flow and dual entry condensing type. The dual entry refers to the dual steam entry ports on the turbine which enables a combination of both HP and LP steam to be admitted to the turbine concurrently. Since the power plant was commissioned in 1997 the turbines have been operating with HP steam only and the LP ports on the turbine have not been used. The "Case 4" design above considered the addition of LP steam to increase the total generation of the units to 70MW.

Producing additional fluid from the reservoir, including LP steam, could imply an increased reservoir extraction and reservoir simulation was performed to evaluate field response under different cases of LP steam utilization. At the present, Salak reference reservoir model is used for deterministic forecast. The quality of the history match obtained on well pressure (steam zone and liquid) and enthalpy give confidence that this reference model is a reasonable predictive tool to evaluate alternative exploitation strategies. The model is a TOUGH2 model that uses an in-house shell program to run in forecast mode. This program automatically activates make-up wells to satisfy a prescribed HP steam requirement schedule and calculates steam deliverability of each production well, using our in-house wellbore simulator and feedzone pressure and enthalpy from TOUGH2 output. Therefore, the forecasting process provides not only steam production profile but also make-up drilling profile. For this evaluation, the model was set up with initial LP steam provided by the assigned existing weak wells and at later times, LP steam production is provided from other existing commercial wells that can no longer provide the requirement for HP steam system.

As described in **Figure 1**, the simulation outputs coupled with cost for surface facility development are then used to determine economic feasibility of the project. The primary value drivers of projects described and recommended are thought to be captured in economic analysis and portrayed through such parameters as NPV and DPI

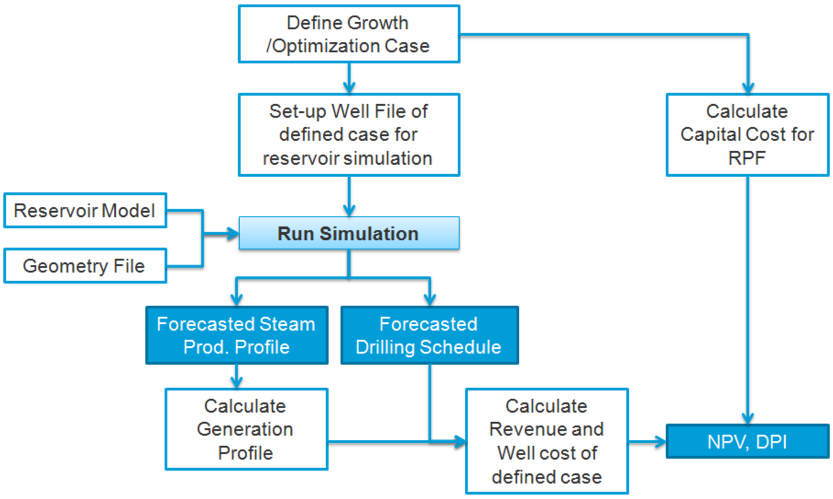

Figure 1: Work Process for preliminary evaluation of LP Steam utilization

Idle wells including the weak wells in Salak field are not located in one area. They are relatively scattered across the field. One concern on utilizing those wells for the existing power plants is the need for lengthy pipe runs. Therefore, another alternative of monetizing the idle wells is to install small power plants located near to the well-pad.

2. MAINTAIN CURRENT GENERATION BY DISPLACING HP WITH LP STEAM (CASE 3B)

Units 4, 5 and 6 are currently operating at the Case 3 design case. Each power plant utilizes only HP Steam at rate of 127 kg/s (1010 kilo-pound per hour, kph), at an inlet pressure of 6.9 bara (100 psia) to produce 65.6 MW of power. In the subsequent discussion, this design case is called the base case.

Table 1: Operating Parameters of Producing 65.6 MW with HP and LP Steam (Case 3b)

Parameter	**Value**	**Unit**
HP Inlet Pressure	88 (6.1)	psia (bara)
HP Steam Flow	882 (111)	kph (kg/s)
LP Inlet Pressure	34.5 (2.4)	psia (bara)
LP Steam Flow	249 (31)	kph (kg/s)

The first design case of LP steam utilization to be evaluated is maintaining current generation of 65.6 MW per unit by displacing HP steam with LP steam (case 3b). This option would make use of the non-commercial wells in the Salak field which are unable to be connected to the existing HP system and would reduce the amount of steam required from the HP wells. The operating conditions for the 65.6 MW operating case with HP and LP steam are shown above in Table 1. These operating conditions have been provided by Fuji, the turbine manufacturer.

At this operating condition there is a reduction in HP steam demand for Units 4, 5 and 6 of approximately 15.1 kg/s (120 kph) per unit. Reducing the HP steam demand by this amount would reduce drilling of approximately 2 - 3 make-up wells. In addition, supply for LP steam demand will then be satisfied by making use of existing wells that are stranded due to insufficient wellhead pressure to be connected to the system. Implementation of this scenario will also result in a drop in turbine inlet pressure and consequently produces a drop in separator pressure in all separators attached to that turbine and also in the wellhead pressure for the connected wells, which will increase deliverability. The pressure drop between separator and turbine and also between separators and wells is updated using the formula

$$\Delta p_{new} = \Delta p_{old} \left(\frac{W_{new}}{W_{old}} \right)^2 \frac{p_{old}}{p_{new}} \tag{1}$$

LP steam is required at a ratio of 1.4 kg/s (11 kph) for 1 kg/s (8 kph) of HP steam. Hence this results in a total increase in turbine requirement and increased fluid extraction from the reservoir. At this point of the evaluation, there is no geographic limitation on weak wells as LP source. Any weak well in Salak field that could meet pressure requirement for LP system is assumed to be available as LP steam.

The Salak reservoir simulation model has been used to conceptually evaluate field performance under the exploitation scenario of utilizing LP steam while maintaining current power generation. Economics of the project will be calculated as incremental net present value (NPV) to current operation strategy (Base case). Therefore as presented in Figure 2, simulation result from this exploitation case is then compared to the predicted field performance from the Base case. Figure 2 shows the power generation plateau (left y-axis) along with the make-up drilling requirement (right y-axis) versus time (x-axis). According to the numerical model, the operation case of maintain current generation by displacing HP steam with LP steam will slightly extend plateau period. This operation scenario will also significantly reduce the number of make-up wells required to maintain sufficient steam for full generation. By 2040, total number of make-up well is 51 for the base case and 47 for LP steam Case. Beside less number of make-up wells, a more delayed drilling program can be resulted from implementing the LP steam Case. The less number of make-up wells and delayed drilling program on LP steam case will eventually reduce the capital cost and add benefit from time value of money respectively.

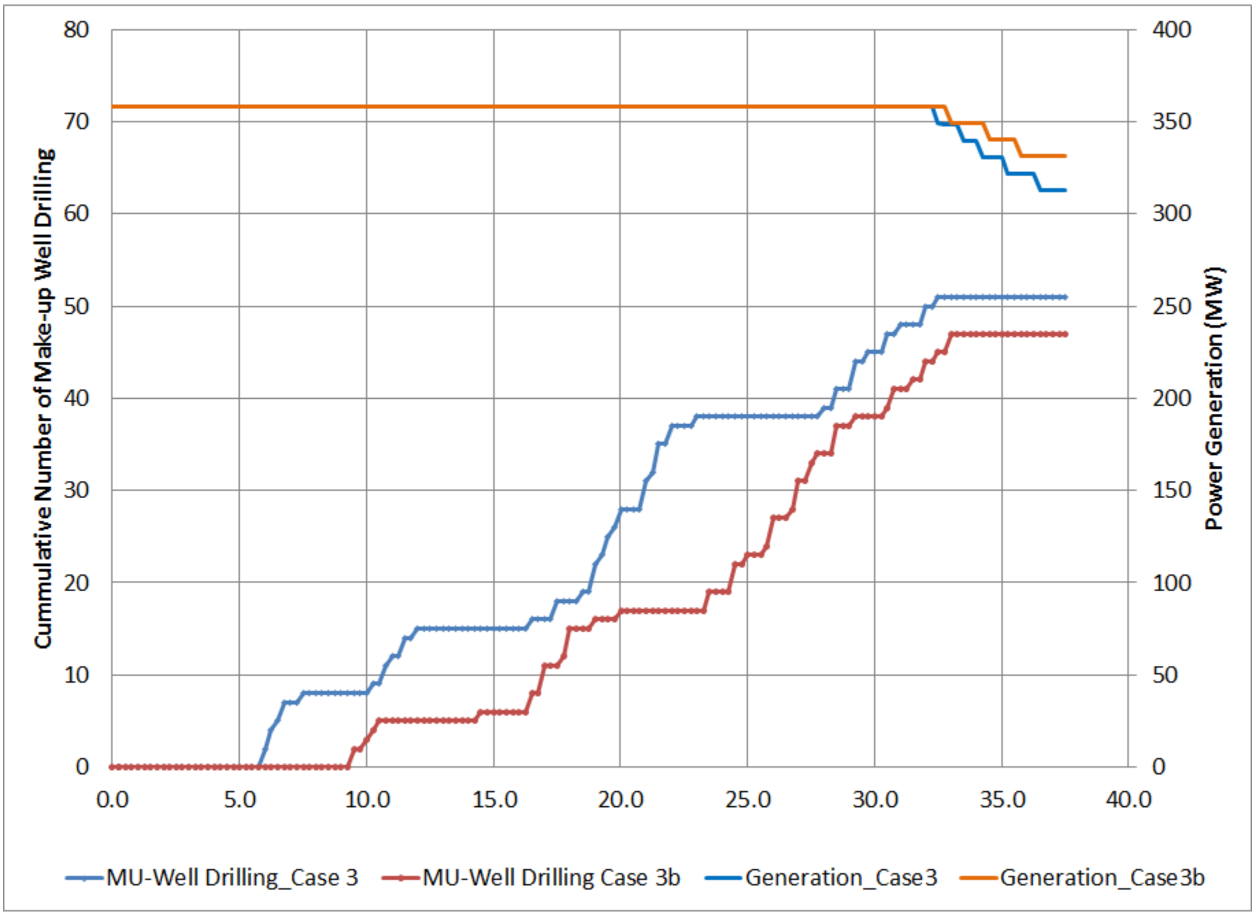

Figure 2: Conceptual Forecast of Field Production and Make-up well Drilling Profile for Case 3 and Case 3b

3. INCREASE UNIT GENERATION TO 70 MW BY ADDITIONAL LP STEAM (CASE 4)

The original design 'Case 4' by Fuji indicated that 70 MW could be achieved from the existing units by adding LP steam to the turbines. The relative HP and LP steam flows are shown in Table 2. The 70 MW case also has the added benefit of operating with a lower flow rate of HP steam than the current operating case with HP steam only. With 942 kph of HP steam to operate 70 MW, there is reduction of HP steam consumption by 60 kph per unit. Given an average steam production of 150 kph, this may equate to delay drilling 1 – 2 wells.

Table 2: Operating Parameters of Producing 70 MW on Power Plant Unit 4, 5 and 6

Parameter	Value	Unit
HP Inlet Pressure	88.5 (6.1)	psia (bara)
HP Steam Flow	942 (119)	kph (kg/s)
LP Inlet Pressure	38 (2.6)	psia (bara)
LP Steam Flow	255 (32)	kph (kg/s)

Assumptions used for prediction runs with reservoir simulation are the same as those on previous case. As can be seen on Figure 3, this scenario not only increases the generation from the units by a total of 13 MW, but also provide additional benefits to Salak field by delaying the need for additional make-up wells especially within Salak contract period which will end in 2040

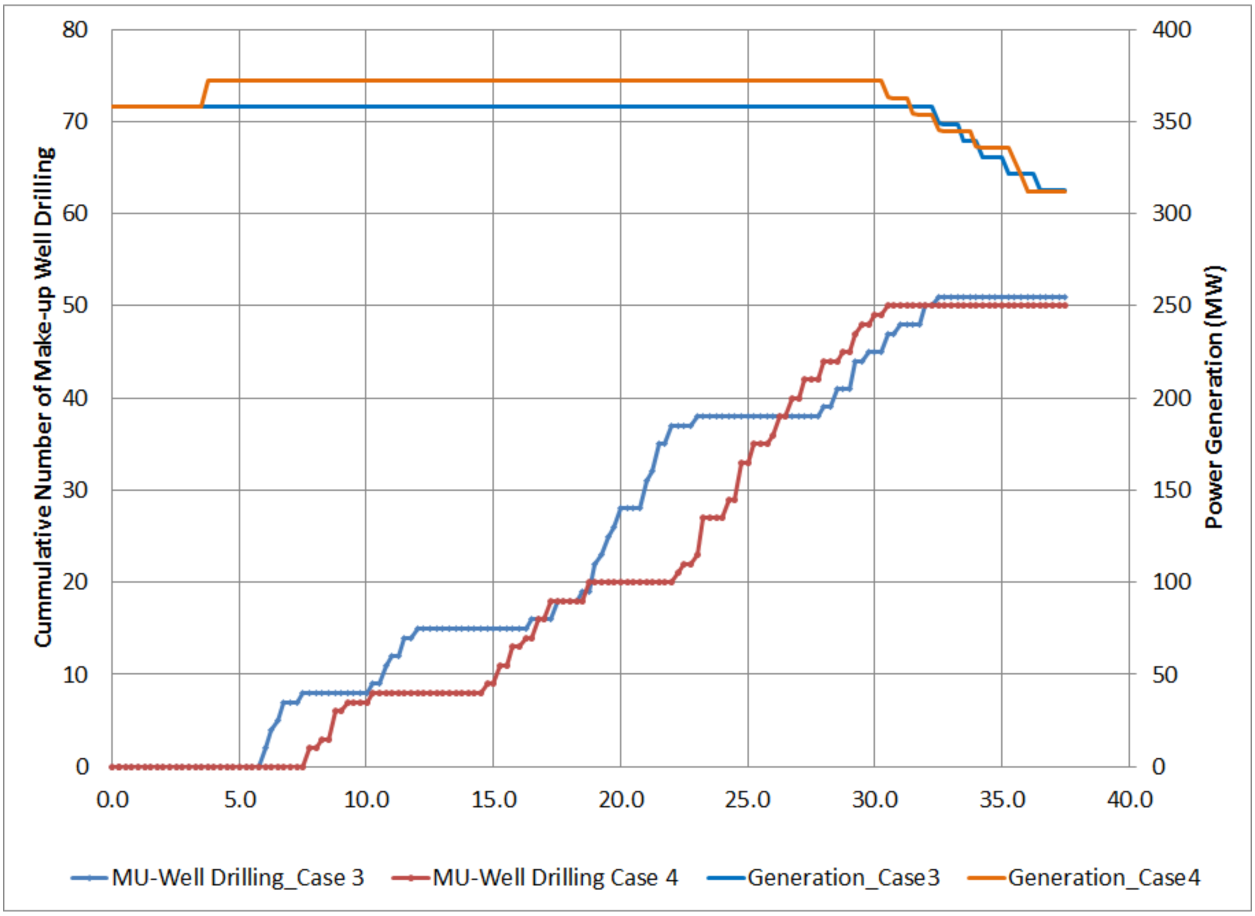

Figure 3: Conceptual Forecast of Field Production and Make-up well Drilling Profile for Case 3 and Case 4

4. PRELIMINARY EVALUATIONS ON POWER PLANT EQUIPMENT AND LP STEM PIPELINE

4.1 Gas Removal System

Review of the power plant ancillary equipment capacity is required to see how additional steam load would affect it. The original design for the gas extraction system was for an NCG content of 1.5% in the HP steam but this is currently 2.0% after some upgrades. This means that the ejectors and liquid ring vacuum pumps are operating at a higher load than expected for the 65.6 MW case (157% of the guarantee 55 MW case). When all ejectors and pumps are operating, the system is able to meet 180% of this load. The NCG content of the LP two-phase wells is much lower (0.6%), so addition of LP steam from these wells will reduce the load on the gas extraction system, rather than increasing it. However, the two-phase wells cannot meet the total LP steam requirement so that some dry LP steam is also required. These wells have a higher NCG content of approximately 1.8 – 2.5%. But even with this contribution, the overall NCG content for the 65.6 MW LP steam case will be less than that for current operation. This means that the existing gas extraction system should be able to meet the new NCG flow, even for the 70 MW case.

4.2 Condenser System and Cooling Water Circuit

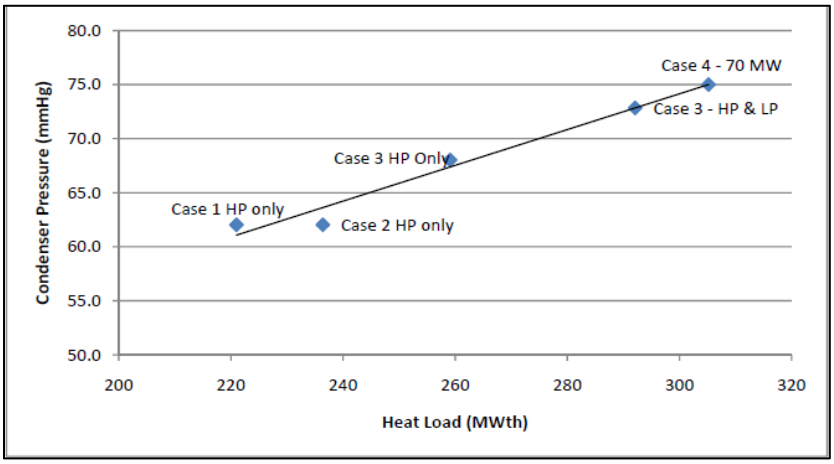

Figure 4: Estimated Condenser Pressure for Case 3 and 4

Although the LP steam has slightly lower enthalpy than HP steam, the increase in total mass flow rate of steam in case 3b and case 4 increases the heat load on the condenser and cooling circuit. At constant cooling water inlet temperature and flow rate, this will result in an increase in condenser pressure. Assuming constant cooling water flow and supply temperature, the pressure in the condenser will increase approximately linearly with heat flow into the condenser. This method is used to estimate condenser pressure for case 3b and 4 based on extrapolation from current operating cases (case 1 – 3). A chart of the extrapolated condenser pressure is shown in Figure 4. For the 65.6 MW case using combined HP and LP steam it is estimated to increase to 73 mmHga, while for the 70 MW case, it will increase to 75 mmHga. This is still far below the maximum operating pressure limit of the existing turbine. Therefore, upgrading the condenser for LP steam cases is not required.

Given expected heat load of the condenser and the constant circulating water flow rate, the range of the cooling tower can be calculated and then use it to estimate cold water temperature from the cooling tower using reference cooling tower performance curve. Using wet bulb temperature of 21.1 ^{o}C, the cooling water temperature for case 3b and 4 will increase from current temperature of 26.5 ^{o}C to 27.5 ^{o}C and 27.8 ^{o}C respectively. This increase is not expected to have much of an effect on condenser performance and therefore no upgrade to existing cooling water pump is anticipated.

4.3 Potential Modification Required to Power Plant

Modification on following auxiliary equipment on the power plants is certainly required to enable turbine operation with dual pressure steam admissions: LP Strainer, LP Main Stop Valve, LP Main Control Valve, Instrumentation, Accumulator Magnetic and Magnetic Valve for Load Shedding. In addition there is also potentiality to perform modifications to existing equipment such as modification of interlock, replacement of oil pump, modification of the governor valve and adjustment of load shedding relay and mechanical valve for the HP and LP lines.

4.4 Low Pressure Steam Pipeline

New production facilities for LP steam are required to supply approximately 750 kph of LP steam to Units 4, 5 and 6. A small additional steam flow will be needed above the flow rate required by the turbine, to allow for condensation in the lines and other losses. The new facilities will include steam piping and vessels on the well pads to separate and transfer the steam to the power plant, and to dispose of the brine to reinjection. A new scrubber will also be required for each unit as well as a rock muffler. A number of criteria will be considered to define wells and production pads as LP steam source, including:

1. The deliverability curve of the well
2. Whether the well produces two phase flow or dry steam (which will impact on the amount of brine that will require disposal)
3. Distance from the power station and the wellhead and LP separator pressure it would operate at having regard to LP steam system pressure drops.
4. NCG content
5. Ability of the well to maintain long term production
6. Impact of extraction from this well on the reservoir
7. Availability of existing infrastructure
8. Access to a brine disposal route for two phase wells

All of the wells currently being considered for LP steam production are the existing weak wells connected to the HP systems on each pad. They will need to be disconnected from this system and reconnected into a new LP installation

5. EVALUATION ON SMALL POWER PLANT

There is an on-going injection realignment program in Salak, which will be fully implemented in 2016. This program requires operation of additional pumps and eventually results in increased demand for electricity house load by up to 5 - 6 MW while output generation from existing power plant keeps steady. To avoid commercial disadvantage from reduction of net generation from Salak field, options to increase power generation have been considered. Modification of existing power plant including development of LP steam pipeline as discussed above may take longer time to complete. Therefore, another alternative for adding generation being considered is installation of small power plant. The small power plant will be installed near to the wellhead to avoid the needs of lengthy steam pipeline and excessive pressure drop. There are two key issues that need to be resolved on small power plant installation: what technology and where to install.

The majority of small geothermal power plants currently in use are either binary or flash technologies. Both have their own proponents and each has its own set of advantages and disadvantages. In the flash steam plant the two-phase flow from the well is directed to a steam separator where the steam is separated from the water phase and directed to drive the turbine. The flash steam turbine systems can either be condensing or non-condensing. In a non-condensing flash system, the steam is separated from the geothermal discharge and fed through a conventional axial flow steam turbine which exhausts directly to the atmosphere. This plant is the simplest and the cheapest in capital cost of all geothermal cycles. The condensing flash system is a thermodynamic improvement on the non-condensing design. Instead of discharging the steam from the turbine to the atmosphere it is discharged to a condensing chamber that is maintained at a very low absolute pressure, typically about 0.12 bar-a. Because of the greater pressure drop across a condensing turbine more power is generated compared to atmospheric exhaust. Non-condensing turbines are therefore less efficient than condensing turbines. In most binary plants, the thermal energy of the geothermal fluid (brine, two-phase or steam) is transferred to a secondary working fluid via a heat exchanger for use in a conventional Rankine Cycle, or Kalina Cycle. The vaporized working fluid, e.g. Isopentane, propane, Freon or Ammonia drives the turbine before being condensed and returned to the heat exchanger in a closed loop. Cooling is generally provided through the use of air coolers. Modular configuration and systems are typically applied to achieve higher plant availability. Binary power plant requires larger foot print than the flash power plant for similar generation capacity. Several criteria have been used to select technology for future small power plant in Salak field which include time for deployment, constructability, operability, reliability, efficiency, capacity, availability, movability (from one to other location), size of foot print, cost, compatibility to geothermal fluid of Salak, and environmental aspects. After a through exercise, the condensing power technology has been considered as preferred alternative.

Several well pads have been identified as potential location for the small power plant. Considered as a pilot test, only one power plant unit is planned to install at this point. First thing to consider in selecting the location is production potential from the well pad. Flow test of the wells are conducted since all of the wells are idle wells with limited recent production performance data. Long term production profile of each well pad is simply estimated using reference range of production decline rate. The second measure for location evaluation is operability which includes availability of back up production well, availability of nearby injector wells and available space. The potential synergy with existing field operation is also considered. The location that can result in minimum or even positive effect to existing field operation is preferred. Last measure to define power plant location is total cost required to develop low pressure brine and condensate injection system, potential pad expansion and construction of electrical transmission line.

6. CONCLUSIONS

Preliminary evaluation on operation scenario of utilizing LP steam indicates that this scenario is economically feasible to be implemented. Implementation of the 65.6 MW LP case will potentially result drilling less wells than that of base case. The 70 MW LP Case will result in 2,900 GW-hr of total additional generation until 2040. Both cases also result in delayed drilling program which eventually provide economic benefit from time value of money perspective. Required additional works involve alternative LP steam production strategies such as variation of locations for LP steam source. Current evaluation with assumption of any weak well in Salak can be utilized as LP steam source will result in highest surface facility cost. This approach would imply the needs to build new production facilities for LP steam at all production pads on the field. Another alternative being evaluated is to install small power plant near to the idle wells location. This option would reduce the cost for installing lengthy pipeline and potentially require shorter time to install.

ACKNOWLEDGEMENTS

The permission of Chevron Geothermal and Power Operation to publish this paper is gratefully acknowledged.

REFERENCES

Acuna, J.A., Stimac, J., Sirad-Azwar, L., and Pasikki, R.G.: Reservoir management at Awibengkok geothermal field, West Java, Indonesia. *Geothermics*, **37**, (2008), 332-346.

Stimac, J., Nordquist, G., Aquardi, S., and Sirad-Azwar, L.: An overview of the Salak geothermal system, Indonesia. *Geothermics* **37**, (2008), 300-331.

Rohrs, D., et al.: Salak Conceptual Model Update. Unpublished Chevron Geothermal Indonesia Report (2005).

Coventry, R., et al: Salak Expansion Project – CPDEP Phase 2A Study. Unpublished Sinclair Knight Merz Report (2011).

Sutter,. J, Kipyego, E., Mutai, D.: The Use of Portable Geothermal Wellhead Generator as Small Power Plant to Accelerate Geothermal Development and Power Generation in Kenya, 37th Workshop on Geothermal Reservoir Engineering Stanford University, Stanford, California, January 30 - February 1, 2012