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Optimizing Production at Salak Geothermal Field, Indonesia, Through Injection Management

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ABSTRACT

It has long been recognized that Salak reservoir performance would be improved through moving injection from the current infield locations to more distal areas. The Salak Optimization project was initiated in 2005 to address this key reservoir management issue, with the objectives of redesigning the production-injection well configuration in a way that mitigated cooling by injection, reduced the production decline rate in the field, and maximized the production of the field going forward. The key strategic decisions for the injection realignment project were identified as: finding new injection location(s); quantifying the amount of brine injection to be moved outfield; conceptual design of facilities required; and the design of replacement injection wells.

Six alternative injection scenarios were identified and assessed through delineation drilling, well characterization, modification of the reference geologic and simulation model, forecasting, and probabilistic economic analysis. Reservoir simulation of the selected alternatives shows a substantial extension of the productive steam plateau of the reservoir from the planned injection projects. Part of the economic value of moving injection will be recouped by converting former injection areas to production, and part through growth of the field's steam cap and lower steam decline rates.

From 2006 to 2009 seven new wells will have been drilled, four of which were in the west, two of which were drilled in the north, and one in the southeast. Injection testing, flow testing, and selective logging and coring provided information on reservoir characteristics in these areas. The delineation results indicate that injectivity and temperature are low to the west of the proven reservoir. When drilled, the western wells were on a higher pressure gradient than the proven reservoir and were not hydraulically connected to it. Hydraulic stimulation has improved the injectivity of the western wells significantly, but high-pressure injection will probably be required to achieve an acceptable injection rate in this area.

Three existing idle wells in the SE were redrilled and one was recompleted to block off shallow zones in 2007-2008. The redrilled and recompleted wells in the SE are on the Salak reservoir pressure gradient or slightly above it, indicating the reservoir extends to this area. Temperature gradients in the area are relatively high and convective at deep levels, further indicating that this area is suitable for deep injection. Awi 15-3RD was capable of flow at commercial wellhead pressure.

Salak Optimization efforts have yielded sufficient deep injection capacity at low wellhead pressure in reworked wells in the SE. Recompleted and redrilled wells provide more than enough injection capacity to move 3000 kph of hot brine to this area from Awi 9, allowing some flexibility in actual well operation. Western wells have low permeability and are outside the Salak reservoir. It is planned to shift injection of power plant condensate into this area. Final design of the injection systems is expected in late 2009 with completion of the SE brine and West condensate projects expected in 2010. Plans for moving about 25% of brine injection to an outfield location will be finalized following drilling and testing of Awi 22 in 3Q 2009 at S5, S of Awi 15.

1. INTRODUCTION

The Salak geothermal field has been producing the steam required for 110-377 MW of power generation for 16 years, with approximately 14,000 to 18,000 kph (~1 MM bbl brine per day) injected in the proximity of the production area during this time (Acuna et al., 2008). Re-injection of brine and condensate was located on the periphery of the proven reservoir as an expedient measure at start-up (Murray et al., 1995; Acuna et al., 2008; Figure 1). It was recognized at the time that breakthrough of cool injected fluid would eventually occur, and would necessitate modification of the injection locations.

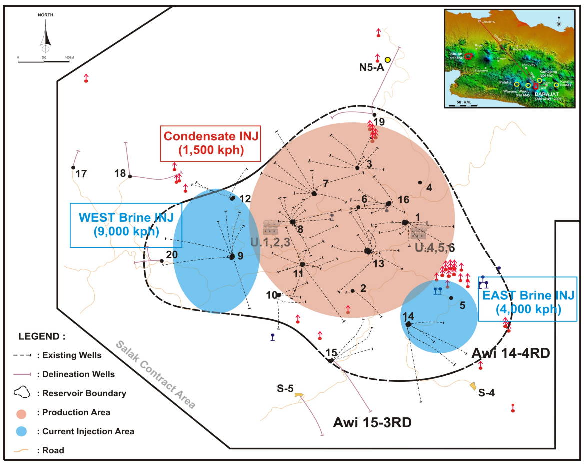


Figure 1: Map of Salak well field with re-injection areas (blue) located in the vicinity of the production area (red), in the periphery of the proven reservoir

The Salak Optimization Project was initiated in March 2005 with a goal of redesigning the production and injection well configuration in a way that mitigated cooling by injection, reduced the production decline rate in the field, and maximized the production potential of the Salak field going forward. Based on preliminary project economics, it was confirmed that the production potential of the field could be increased through expansion of the production area and moving injection outside the proven reservoir boundary. The project was approved in July 2005, with the business justification based upon a predicted increase in production and NPV relative to "As-is" operation and the understanding of what might be achieved through a successful optimization. The options evaluated were to: a) invest in make-up drilling as required by the current exploitation strategy ("As-is") with and without specific resource production facility upgrades, and b) pursue an optimum strategy from a number of possible alternative production and injection scenarios.

Based on geophysical surveys (MT, TDEM and gravity) performed in 2004, two areas to the west and north of the proven reservoir, were identified as prospective based on extensions of the low-resistivity anomaly that was defined earlier over the proven reservoir (Nordquist, 2004; Stimac et al., 2008). The maximum inferred extent of the hydrothermal clay associated with these anomalies is shown in Figure 2. Additional geologic studies of these areas were conducted later, and the results were summarized in a revised geologic and structural map of the area (Stimac et al., 2008). Perhaps the most significant results from this work were to confirm that the dominant N to NE trend in surface faults and fractures extended to the Cianten caldera to the west of the proven reservoir, that the caldera sequence appeared to consist of significantly older volcanic rocks than those present in main field, and identification of the eastern caldera ring fault. The main reservoir appears to be bounded by NNE-trending normal faults that have localized younger, thicker and more permeable volcanic accumulations than in the adjacent areas to the west and east (Stimac et al., 2010a).

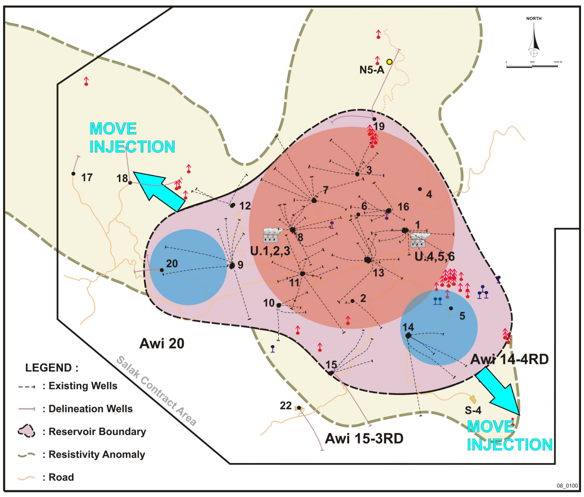


Figure 2: The relationship of the extensions of the low-resistivity anomaly to the proven reservoir. Two areas, to the west and north of the proven reservoir, were identified as prospective re-injection areas. Delineation wells (purple) and proposed outfield injection locations (N5A, S4 and S5) are located within the anomaly

Field monitoring and process modeling indicated that a number of production wells in the field were being cooled by the injected brine, resulting in relatively high production decline rates. Recent modeling efforts and experiences in other geothermal fields indicate that unless injection cooling is mitigated, it would lead to a significant loss in production potential at Salak field. Perhaps more importantly, full field numerical simulation indicated that infield injection inhibits steam cap growth, and that by moving power plant condensate and approximately 10-15% of the current brine injection outfield, the steam cap would expand significantly and brine production would decline to a lower level. This scenario added substantially to the project value by allowing conversion of former infield injection areas to production and by delaying and reducing future make-up drilling requirements.

2. INJECTION ALTERNATIVES AND DRILLING RESULTS

A number of alternative areas to the west, north, south and southeast of the proven reservoir have long been considered prospective for injection at Salak (Stimac et al., 1997). These alternatives were re-evaluated and prioritized in light of new geophysical data in 2005, and facility design considerations (Nordquist, 2004; Rohrs et al., 2005).

2.1 Injection Alternatives

The area to the west of the Salak reservoir was considered the best candidate for moving injection based on its proximity to the main brine-producing area of the field (Awi 7-8-11-10 area) and its lower elevation, whereas the northern area was considered the best candidate for production expansion based on its proximity to existing steam cap, and location along what is considered the main outflow pathway of the proven reservoir based on the distribution and chemistry of hot springs and fumaroles (Stimac et al., 1997; Rohrs et al., 2005). The SE was considered less prospective because of a smaller low resistivity extension (Nordquist, 2004).

A strategy table helped frame and define the injection realignment alternatives and the key decisions that would be required for each alternative (Figure 3).

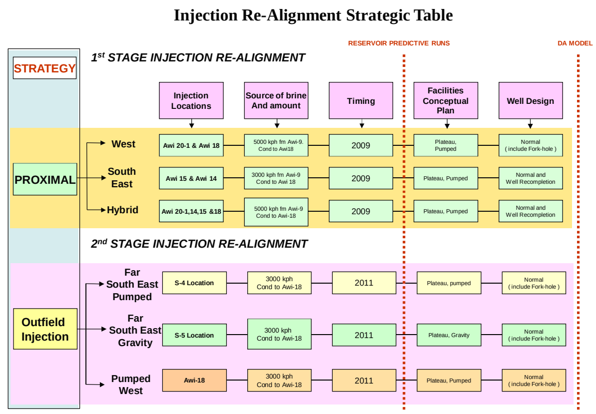


Figure 3: Injection Realignment project strategy table

Since delineation drilling would necessarily be phased in time as new pads and roads were constructed, the outcome of delineation drilling was factored into the strategy table. This resulted in a decision tree-like structure to selection of the preferred alternative. In this manner, the information from the delineation wells was expected to mitigate the largest risk of the injection realignment project, namely the risk associated with selecting the injection location with the most favorable combination of characteristics. The strategy table was revised as delineation well results and Peer

Reviews led to elimination of low value alternatives. The key strategic decisions for the injection realignment project were identified as: 1) new injection location(s), 2) amount of brine to be injected, 3) conceptual design of facilities required, and 4) replacement injector well design.

2.2 Delineation Drilling Chronology and Results

Figure 4 shows the three areas of delineation drilling at Salak from 2006-2009. Three pad locations, W9 (Awi 17), W8 (Awi 18) and N3 (Awi 19), were selected in 2004-2005 for construction based on the geophysical interpretations (Nordquist, 2004; Rohrs et al., 2005). The first two of these locations were intended to test the Far West and Proximal West Strategies.

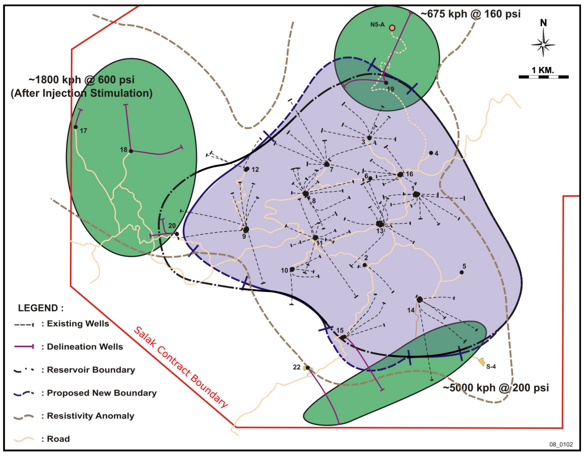


Figure 4: Summary of the estimated injection capacity of each area based on well tests done up to Q3 2008. The initial capacity of western wells was about 187 kph at 600 psi, whereas stimulation of 18-1 increased this to about 1200 kph at 600 psi. Awi 15-3RD flow tests indicates that the well is capable of sustaining commercial production at a rate of 70 kph

Delineation drilling began with Awi 17-1 and 18-1 in 4Q 2006. Since these wells indicated low permeability and temperature in the west, the Salak Subsurface Team began considering additional options including a program of redrills and recompletions of existing SE wells.

A more proximal western pad, W7 (Awi 20), was constructed near the bottom hole location of Awi 9-6 in 2007, after the more distal western locations yielded low injectivity. Awi 9-6 is the westernmost productive well in the field. Additionally, two existing wells on the Awi 15 and 14 pads were selected for redrilling to evaluate the deep injection potential in the Proximal SE. Awi 15-3 and 14-4 were selected because they were idle wells that were ideally located for redrilling to potentially more favorable injection targets at the fringes of the low resistivity anomaly (Nordquist, 2004). Redrilling allowed blocking off any shallow permeability encountered. However, drilling at the Awi 14 pad was delayed due to the need to repair landslide damages sustained in 2003. Thus Awi 15-3RD was the first of the SE projects to be implemented (3Q07). This well targeted deep permeability along a major structure that has served as a conduit for eruption and shallow intrusion in the Quaternary (Stimac et al., 2008).

In the north, one well pad (N3, or Awi 19) was constructed instead of the originally proposed two pads due to revisions in the resource assessment and in an effort to reduce the project environmental footprint and risk. Three Awi 19 wells were drilled to test production potential north of the proven reservoir in 4Q07. Awi 19-1 was plugged and abandoned due to shallow drilling problems, and Awi 19-2 was directed to the west to intersect N to NE-trending faults thought to control outflow of the system to the N. Awi 19-3 was drilled far north to test both the extent of shallow reservoir near N3 and the deep reservoir potential in the area of the proposed N5 location (Fig. 4).

Awi 20-1 was drilled as a multi-lateral completion in 1Q08 (Stimac et al., 2010b). The well had a deep cemented casing shoe to minimize the risk of shallow injection returns. After the Awi 14 pad was made ready for drilling, Awi 14-4 was also redrilled in 3Q08.

It was recognized that other Awi 14 wells caused injection breakthrough primarily due to shallow zones that were connected to nearby producers. A method was devised to recomplete these wells so that their shallow zones would be eliminated. External casing packer systems were run to isolate and cement off these zones. Two wells, Awi 14-1 and 14-3, were selected to test the feasibility of this method of recompletion, with a contingency to redrill the wells to more distal targets should the recompletion fail.

Two additional wells, Awi 18-2 and 22-1 were drilled in 2009, but these wells have not yet been fully tested at this time. Therefore these wells will not be described below.

2.2.1 Delineation Well Results

Table 1 summarizes the main results of the delineation drilling program. Well temperatures surveys from these areas are summarized in Figure 4, along with data from nearby existing wells. Some production make-up wells also provide new information regarding field margin conditions.

Overall five new wells (6 penetrations due to 1 multi-lateral well) were drilled, three of which were in the west, and two of which were drilled in the north. Three existing idle wells in the SE were redrilled and one was recompleted to block off shallow zones. Actually both 14-1 and 14-3 were recompleted, but the original penetration of 14-3 was lost as a result of getting stuck (twist-off) while drilling out cement. It should be highlighted that significant innovations were made in this drilling program, including:

- drilling the first multi-lateral geothermal well in Indonesia (Stimac et al., 2010b), and
- block-off or isolate parts of an existing geothermal wellbore for the first time.

Table 1. Injection capacities and locations of delineation wells drilled or recompleted from 2006-2008.

Well	Status	Strategy	Total Depth/Elev	Estimated Injection Capacity	Thermal Gradient	Connectivity
			ft MD/ft RSL	kph@WHP (psi)	CD or AD	C or UC
17-1OH	New	Far West	4435 (-1037)	0 @ 200	CD	UC
18-1OH	New	Prox West	9642 (-5489)	50 @ 600	CD	UC
				580 @ 600		
20-1OH	New OH	Prox West	8872 (-5363)	85 @ 600a	CD	UC
20-1FL	New FL	Prox West	8034 (-4511)	52 @ 600 a	CD	UC
20-1TOTAL				**670 @ 500**		
19-1OH	New	Prox N	1600 (+2542)*	0 (P&A'd)	-	-
19-1ST			1171 (+2971)*			
19-2OH	New	Prox N	8600 (3637)	1050 @ 100	AD	C
19-3OH	New	Prox N	9574 (3713)	675 @ 100	AD	UC
15-3RD	Existing	Prox SE	10000 (-5063)	1100 @ 160	AD	C
				***70 kph stm**		
14-4RD	Existing	Prox SE	9110 (-3391)	1320 @ 200	AD	C
14-1RC	Existing	Prox SE	8406 (-4405)*	1580 @ 200	AD	C
14-3RD	Existing	Prox SE	9512 (-3998)*	1350 @ 200	AD	C

OH, original hole; FL, forked leg; RD, redrill; ST, sidetrack; RC, recompletion; CD, Conductive; AD, Advective; C, connected; UC, unconnected. Values in red for 18-1 are for well capacity after hydraulic stimulation.
*19-1OH and RD were P&A'd due to collapse of the 26" hole.
*15-3RD produced 70 kph steam upon testing.

Logging and coring was executed in four wells without any significant incidents. Although not fully summarized here, this data adds significantly to our understanding of these areas and will pay dividends in better reservoir models for the life of the contract (e.g., Yoshioka and Stimac, 2010).

Overall, the delineation results indicate that injectivity and temperature are low to the west of the proven reservoir, and that the reservoir boundary lies between Awi 9-6 and Awi 20 (Figures 4 and 5 and Table 1). The western wells lie on a higher pressure gradient than the proven reservoir and are not hydraulically connected to it. Hydraulic stimulation of Awi 18-1 has improved the injectivity of the well significantly, but high-pressure injection is still required to achieve an acceptable injection rate (Yoshioka and Stimac, 2010). Hydraulic stimulation of Awi 20-1 yielded a similar result.

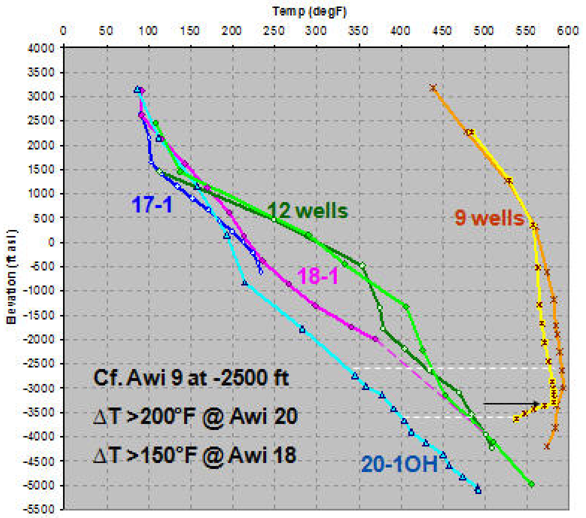


Figure 5: Summary of reservoir temperatures versus elevation (ft asl). Comparison of conditions at 2500 ft bsl in Awi 18 and 20 relative to Awi 9 indicate large differences in temperature

Of the two wells drilled to the north, Awi 19-2OH appears to have penetrated steam cap similar to that found at Awi 3 and 7 pads, as well as encountering some deep permeable zones, but the overall permeability of the well is relatively low, possibly due to mud damage. Awi 19-3OH did not encounter steam cap conditions and is on a higher pressure gradient than the proven reservoir, indicating it is not hydraulically connected to it. Coiled tubing cleanout and acid stimulation of Awi 19-2 was conducted but the well has not yet been flow tested. These wells are not currently being considered for injection because of their proximity to many of the new production wells drill in the north part of the field. Further evaluation of extending production to the north is ongoing.

All the wells redrilled or recompleted in the SE appear to be on the Salak reservoir gradient or slightly above it, indicating the reservoir extends to this area. Temperature gradients in the area are relatively high and convective at deep levels, further indicating that this area is suitable for deep injection. Awi 15-3RD was capable of flow at commercial wellhead pressure during a short flow tests, producing an estimated 70 kph steam at 120 psi.

The current estimate of injection capacity of each delineation area is summarized in Figure 4 and Table 1, although these numbers are generally expected to increase as wells are further tested, stimulated, and put in service. Increase in the SE may be most significant since these wells are connected to the reservoir.

Approximately 5000 kph of injection capacity is available in reworked wells in the SE. This is more than enough injection capacity to move 3000 kph of hot brine to this area, allowing some flexibility in actual well operation. In the west, current capacity is about 1100 kph at 500 psi wellhead pressure. Awi 18-2 was drilled in 2009, with a similar initial capacity to Awi 18-1. Hydraulic stimulation of the well is being planned. It is expected that moving 1500 kph of condensate injection from Awi 12 to the west will eventually be reached by using Awi 18-1, 18-2 and 20-1. In the north, Awi 19-3OH can be used as an injector, especially to facilitate production testing of Awi 19-2OH. However, utilization of this well awaits further testing.

3. SIMULATION AND PREDICTIONS

A full field numerical simulation model has been developed for Salak for forecasting field performance under range of production and injection scenarios. The quality of the history match obtained for well pressure (steam zone and liquid) and enthalpy gave confidence that it is a reasonable predictive tool to evaluate alternative exploitation strategies, although it is recognized that a single model may not capture the full range of uncertainty in reservoir behavior. After elimination of the Far West injection option (poor results at Awi 17-1), five other strategies were developed and evaluated, and served as primary input to decision analysis and project selection. These strategies are briefly described below.

1) As-Is:

- Keep current injection locations, with some new wellpads for production included (e.g., C1 or Awi 21).
- Allow conversion of Awi 2 wells to production (when possible).

2) Proximal SE

- Move 3000 to 6000 kph from Awi 9 to SE injectors (Awi 14/15 wells).
- Keep injecting at Awi 9-6.
- Convert Awi 2 and Awi 9 wells to production (when possible).

3) Outfield Injection Stage 2a Evaluation

- All the Proximal SE scenario plus Awi 12 condensate injected outfield completely

4) Outfield Injection Stage 2b Evaluation

- Perform all injection (brine/condensate) in areas not connected to the reservoir

5) Hybrid

- Similar to “Proximal SE” scenario, but with all condensate and part of the brine injected outfield

Numerical modeling indicated that all the injection strategies outperformed the As-is Strategy, confirming the importance of injection optimization. The As-is Strategy with resource production facility enhancements performs significantly better than without these enhancements. The Proximal SE injection strategy provides increased flexibility to the Salak injection system. This option provides high quality infield injection locations for near- and long-term Salak injection management. However, the best resource performance is obtained by implementing SE Proximal injection, and moving approximately 10-15% of the total brine and all of the plant condensate (1500 kph) injection to outfield locations to achieve a "net 3000 kph" of total injection outside the proven reservoir (Hybrid Strategy).

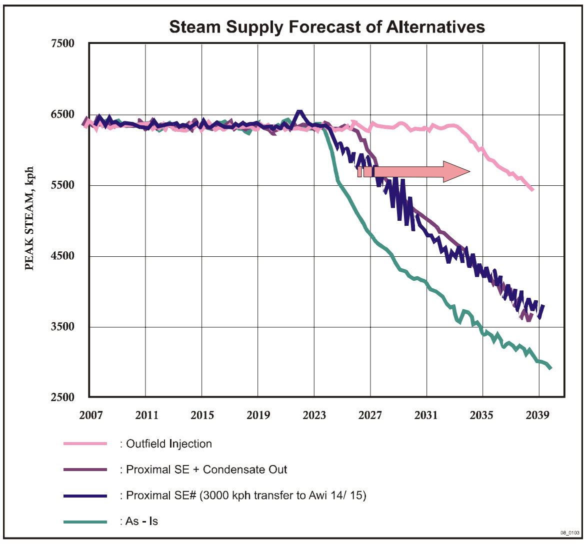


Figure 6: Peak steam forecast for alternative injection and optimization scenarios

Outfield injection areas to the west (Awi 18 and 20), south (S-5) and southeast (S-4) were considered in this study. The West option allows immediate implementation of the Hybrid injection optimization strategy (3000 kph net outside injection), but has relatively high implementation and operation and maintenance costs. S-5 (Awi 22) might have better injection capacity than the west, but be more connected to the proven reservoir. Its primary advantage is that it will allow gravity injection rather than require pumps. In addition S-5 may have some value in proving additional production opportunities. S-4 may also have potential for future production and/or injection optimization, but it was decided to postpone construction of this pad until the west and south options were fully evaluated.

Reference model predictions for the Salak field, updated based on recent drilling results, indicates that fully optimizing and integrating the Salak resource production facilities will extend the 377 MW generation "plateau" by ~8 years to 2024. Relocating Awi 9 injection to the Proximal SE extends the "plateau" by another ~4 years; but this is best accomplished in two stages. The first stage entails moving 3000 kph of brine from Awi 9 to deep Awi-14/15 wells. The second stage entails moving 1500 kph condensate from Awi 12.

A Hybrid Strategy wherein the Proximal SE is combined with 3000 kph net injection outside provides the longest generation "plateau" of all the modeled scenarios. In addition this Hybrid Strategy may facilitate additional opportunities such as Binary or low-pressure flash power generation.

<u>1. Proximal SE Hot Brine Injection:</u> A package of selected well redrills and recompletions at Awi 14 and 15 were accomplished as described above to shift about 3000 kph of hot brine from Awi 9 to the SE. This shift in injection location can be accomplished with minimal cost by augmenting existing facilities with additional pumping capacity and an additional 20" pipeline. Implementation of the SE Proximal injection strategy can be seen as an incremental step towards delineation of more distal SE locations at S4 and S5. The S5 location was proposed based on promising results from Awi 15-3RD, results of geologic mapping (Fig. 5), and the expectation that a pipeline route could be found that will allow gravity flow of brine from the west side of the field to the location.

<u>2. Proximal West Plant Condensate Injection:</u>

Awi 18-1, 18-2 and 20 wells will be used to shift all power plant condensate (1500 kph) from Awi 12.

West (Awi 18/20)

The west has the lowest injection capacity but also has the lowest P50 value for % injectate return (~10%). If this estimate is correct, ~3300 kph injection capacity would be required to achieve a net of 3000 kph outfield injection in this area.

Currently Awi 18-1 can accept about 630 kph at 655 psig WHP, and it has a projected capacity of ~875 kph at 1000 psig injecting WHP. Awi 20-1 can accept 560 kph at 500 psig WHP. It is estimated that three to four additional wells would be required to achieve 3000 kph net outfield injection in this area. Awi 18-2 has a similarly low initial capacity to Awi 18-1 and will require stimulation.

South (S-5)

The southern portion of the contract area may have better deep permeability and temperature than the west and far SE, and therefore yield a higher injection capacity with fewer wells (Acuna et al., 1997; Rohrs et al., 2005; Stimac et al., 2008). However it is also likely that this area will not be completely isolated from the production zone as described above. Thus the better capacity may also mean higher % injectate return. With some percentage of the brine returning to the reservoir a larger about of brine injection will be required to achieve the target 3000 kph net voidage. The other attractive feature of the S5 option is that gravity injection is possible. If this area does not prove suitable for outfield injection, it may be suitable for production based on the flow test of Awi 15-3. Finally if the S5 well is suitable for injection, it may be used as an incremental change to SE Proximal injection, which may further reduce injection impacts in the short-term.

Benefits of injecting outside the interconnected fracture network from reference model predictions are that it:

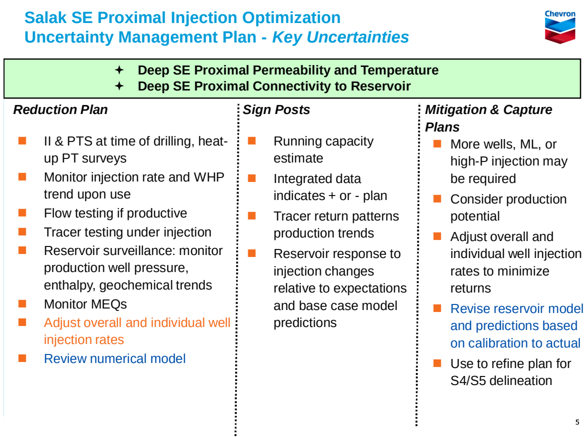
- Extends steam supply "plateau" by another ~6 years;
- Significantly reduces the number of future make up wells required by facilitating conversion of Awi-2/9 injectors to production and improving overall reservoir performance; and

- Might allow for growth opportunities (e.g., Binary or other new plant capacity).

In order to optimize reservoir performance the reference model predictions indicate that a "net" voidage of ~3000 kph is required.

4. PROJECT STATUS AND UNCERTAINTY MANAGEMENT

An Uncertainty Management Plan (UMP) aims to identify the key uncertainties at the beginning of a project and develop plans that will reduce negative impacts and capture positive impacts more effectively. Action plans driven by such planning reduce subsurface uncertainty, mitigate downside outcomes, and capture upside outcomes. The UMP is a living document that contains resolution options, sign-posts for outcomes, and mitigation/capture plans. Some of the key uncertainties, sign posts and mitigation and capture plan for the SE Proximal 3000 kph project are summarized in Figure 7.



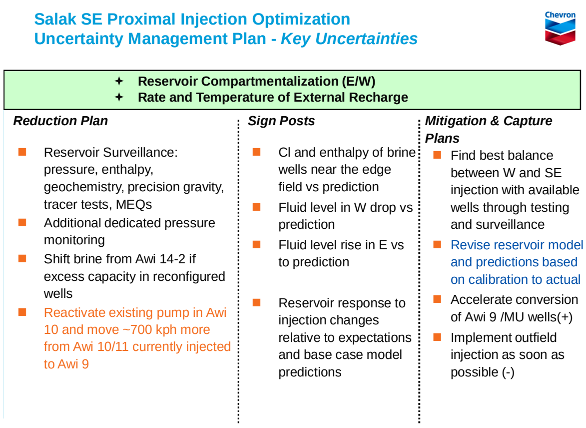


Figure 7: Examples of subsurface Uncertainty Management issues for the SE Proximal Injection project

4.1 Key Uncertainties for Outfield Move

Key uncertainties for Stage 2 of the Salak Optimization project have been identified and captured, and the UMP will be updated as new data from SE Proximal 3000 kph implementation and delineation wells become available. A brief summary for each delineation area is provided here, to highlight some of the key issues. Currently the following uncertainties are identified for the alternative delineation locations.

4.1 Outfield Move

<u>4.1.1 Proximal West</u>

- Reservoir Quality (sustainability and connectivity)
- Well design (shallow/deep/fork or single penetration)
- Operability and long-term maintenance cost of high-pressure injection system

More detail is provided for the West, since four wells have already provided some information on that area. Since the permeability and temperature of the reservoir in this area are low, the key issue is how to make a commercially viable project with low injectivity. Permeability is now fairly well constrained for this area, but uncertainty remains regarding the stimulation potential of the wells and the best stimulation methods to use. There is also some uncertainty about the long-term trend in injection rate for the area if both condensate and brine are injected to this area with limited permeability.

<u>4.1.2 Distal South (S5)</u>

- Reservoir Quality (injection rate and connectivity)
- Obtaining land/operation in Tea plantation

Awi 15-3RD provides some applicable reservoir data for the S5 location. For S5 there is significant uncertainty regarding reservoir quality, especially whether a high injections rate area with low connectivity to the production field can be delineated. Geologic factors suggest that reservoir quality, especially temperature, may be higher at S5 than in the west, but that the higher the reservoir quality the higher the probability that the area is connected with the proven reservoir. High connectivity will not fully satisfy the requirements for outfield injection, although it may indicate the location has value for production. Table 2 summarizes subsurface assessments of ranges on injectivity at S5 relative to the west, and the risked percentage of injection that is expected to return. Another critical uncertainty was whether an agreement to buy or lease land for pad construction could be consummated in a timely manner. Agreement was successful reached with the landowners and 22-1 is being drilled in 3Q09 well.

Table 2. Estimated Outfield Injection Well Capacity in kph.

	WEST (Awi 18/20 after stimulation	South (Awi 22/S-5)	Far SE (S-4)
P10	300	150	50
P50	450	500	400
P90	600	1500	1000

4.2 Salak Optimization Value Drivers

The primary value drivers of projects described and recommended in this report are thought to be captured in economic analysis and portrayed through such parameters as NPV and DPI. However, some value drivers may not be directly included in economic calculations, or be difficult to accurately portray in decision analysis because of large uncertainties on their economic impact. This section summarizes some value drivers that the Salak Optimization

Team considers important, and that may have significant upside or downside impacts of the Stage 2 optimization.

4.2.1 Reservoir

The main reservoir-related value drivers in this project are the characteristics of potential injection areas such as overall ***Reservoir Quality*** (high permeability and temperature) and ***Connectivity*** to the production zone. A very large range in permeability and temperature is common at the margins of geothermal reservoirs that typically dictate the injectivity of wells. For purposes of this project, the ideal outfield injection location is one that exhibit high reservoir quality and low connectivity to the production zone. As discussed in the Section on numerical simulation, the extent to which a given injection area (West, S5, S4) is hydraulically connected to the production field has a significant impact on selection of the best alternative.

Another reservoir-related value driver is the ***Value of Information*** provided by a particular delineation target or strategy. It is recognized that there is potential for delineation in a particular area to identify upside potential for production that would not otherwise be identified, as well as provide information that can be used to target future wells and to improve the field geologic and reservoir simulation models. A significant well characterization program is being undertaken, and will be leveraged to improve field models and reservoir management efforts.

4.2.2 Commercial and Operational

Non-reservoir value drivers includes the ***Operability and Constructability*** of the facilities required for a given injection option. In the case of Stage 2, high-pressure pumping is being considered in some options, however, such a strategy is not common in existing geothermal operations and therefore carries a higher degree of uncertainty regarding estimates of planning, construction and O&M costs.

Geothermal energy development projects have low carbon emissions, and thereby have a lower impact on Greenhouse Gas Emissions than projects using carbon-based fuels. Currently no economic parameter captures this value to society for the Salak project, although Chevron recognizes the importance of developing sustainable sources of energy. Similarly, maintaining a critical mass of intact forest ecosystems benefits global and local communities in many ways. One major benefit of mountain watersheds is a sustainable source of clean water for multiple uses. ***Minimizing the overall footprint*** of Salak geothermal development on the Gunung Halimun-Salak Protected area is considered a value driver of the project. An example of how this value driver influenced the project is the decision to construct only one pad to the north of the field (N3), rather than two (N3 and N5) as was originally planned. Other new locations were constructed in areas where forest had already been partially replaced by agricultural use. These decisions reduced the environmental impact to the area.

The final value driver being considered by the Salak Optimization Team is how the project may ***enhance long-term Chevron Geothermal Strategic Flexibility***. The primary issue here is how investment in Salak injection optimization now may free up key resources for other growth projects in the future. It is expected that the injection optimization will reduced the reservoir monitoring and make-up drilling demand of the project, which will free critical organizational capacity for other high value projects in the years to come.

CONCLUSIONS

Re-injection of brine and condensate has always been the key reservoir management challenge for the Salak field (Murray et al., 1995; Acuna et al., 2008). The Salak Optimization Project was initiated in March 2005 with a goal of redesigning the production and injection well configuration in a way that mitigated cooling by injection, reduced the production decline rate in the field, and maximized the production potential of the Salak field going forward. By the end of 2009, seven new wells (Awi 17-1, 18-1, 18-2, 19-2, 19-3, 20-1, 22-1) will have been completed on new distal locations, and 4 wells on the Awi 14 and 15 pads (SE) will have been redrilled and/or recompleted to deeper and more distal targets to identify and characterize new injection areas. It is expected that 3000 kph of brine will be shifted from Awi 9 to the SE wells, whereas power plant condensate will be shifted to selected western wells (Awi 18 and 20) by the end of 2010. Planning for moving additional brine from Awi 9 awaits the completion and testing of Awi 18-2 and Awi 22-1 (S5).

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