

COILED TUBING ACID STIMULATION: THE CASE OF AWI 8-7 PRODUCTION WELL IN SALAK GEOTHERMAL FIELD, INDONESIA

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ABSTRACT

Awi 8-7 is a new well drilled in the Salak geothermal field during 2004. Despite promising indications, the initial steam flow rate from this well was below expectations. A completion test that consisted of a pressure-temperature-spinner (PTS) survey, an injectivity test, and a pressure fall-off (PFO) test was conducted to diagnose the problem and to characterize the initial state of individual permeable zones. Injectivity and pressure fall-off tests indicated that Awi 8-7 had a low injectivity index (II) and a positive skin. These data and the fact that the well lost about 94,500 bbls of water-based mud during the drilling process suggested the presence of near-wellbore formation damage.

An acid stimulation treatment was designed and carried out to improve well performance. The treatment used a hydrofluoric acid system known as Sandstone Acid that was placed at the target zones via two-inch coiled tubing. Post-acidizing well test analysis demonstrated that the acid stimulation successfully improved overall well characteristics. Total II increased from 2.56 to 6.55 kph/psi, permeability-thickness (kh) product increased from 252,000 to 403,000 md-ft, and the skin decreased from +2.2 to -1.2. A flow performance test after the acid job has confirmed a significant improvement of Awi 8-7 deliverability: maximum discharge pressure increased from 211 to 297 psig, while production output at a wellhead pressure of 150 psig increased from 70 to 160 kph of steam.

1. INTRODUCTION

Make up steam supply production wells are now being drilled in the Salak geothermal field, a liquid dominated geothermal resource operated by Chevron in Indonesia. Well Awi 8-7, a 6360' deep production well was drilled in the 2004 make up steam supply drilling program. After completion, well 8-7 delivered steam at sub commercial steam flow rates at system operating pressures. To improve well 8-7's

steam production, a comprehensive stimulation program was planned and executed on the well. The stimulation program scope included diagnostic work to identify the causes of sub commercial performance, evaluation of the most effective stimulation techniques, stimulation design and execution, and assessment of the obtained results. This paper discusses the successful stimulation project of well, Awi 8-7.

2. AWI 8-7 WELL CHARACTERIZATION AND DIAGNOSIS

2.1 Heat-up Survey

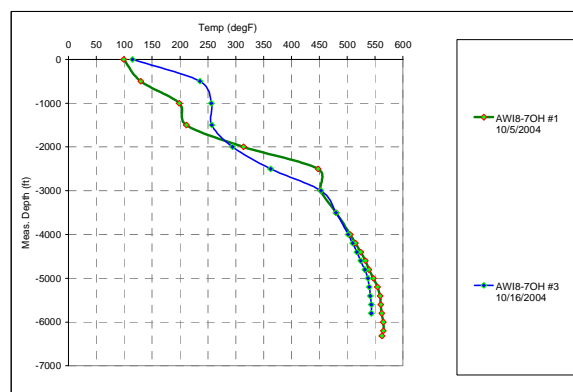


Figure-1: Heat-up survey of Awi 8-7 after drilling completion

A series of shut in pressure-temperature (PT) surveys at Awi 8-7 was conducted following the drilling completion. As shown in Figure-1, the well was fully heated up after twenty days. A high temperature region of 505 – 565°F in the 2400 ft of open-hole production interval made this the hottest well in the vicinity. However, discharge tests showed that the well delivered significantly less steam than surrounding wells.

The drilling history was reviewed to see if the formation had potentially been damaged through invasion of drilling mud, drill cuttings, and cutting fines. The drilling record showed that the well lost about 94,500 bbls of water-based mud in the open hole. In parallel with the drilling history review, a completion test was designed to assist in diagnosing the well performance problem.

2.2. Injection PTS Survey

A completion test at Aw1 8-7 was conducted 40 days after drilling completion, before the stimulation. The test consisted of an injecting PTS survey, an injectivity test, and a pressure fall-off test.

Initial analysis of injection PTS data provided information about the location of the permeable zones and the amount of liquid accepted by each zone. An injecting wellbore model was then constructed by matching simulated wellbore fluid velocity, wellbore pressure, and total injection rate to the measured data (see Figure-2) to identify the individual II value of each permeable zone (Acuna and Arcedera, 2005). Wellbore simulation was performed using the in-house Unocal wellbore simulator. Table-1 shows the injected fluid and II distribution at each permeable zone.

Table-1: Injected fluid and II distribution resulting from injection wellbore simulation

Entry Depth (ft-MD)	Fluid Accepted (kph)	Injectivity Index (kph/psi)
4400	120	0.82
5380	160	0.60
5800	60	0.26
6250	140	0.53
6310	90	0.34

2.3. Injectivity Test

The injectivity test was conducted by continuously recording down hole pressure while decreasing the water injection rate from 30 barrels per minute (bpm) by 5 bpm increments every 1 hour until the final rate of 5 bpm was reached. The pressure tool was set at a depth of 5500 ft. which is near the mid-point of permeable zones. Figure-3 shows the pressure response as the rates were decreased. The pressure at the end of the 1-hour period for each rate was used to construct the graph of injection rate vs. measured pressure shown in Figure-4. The graph shows that the

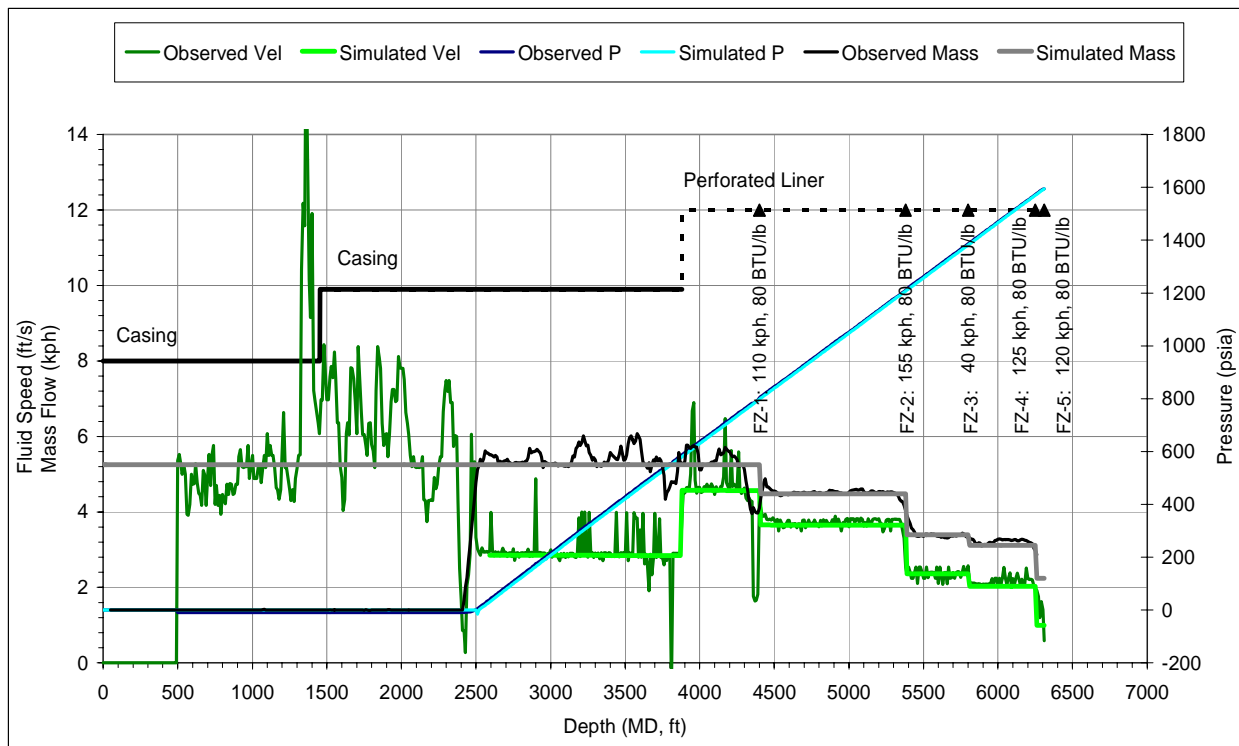


Figure-2: Pre-acidizing wellbore simulator match of injection pressure and fluid velocity on Aw1 8-7

initial II of Awi 8-7 (before being stimulated) was 2.56 kilo pounds per hour per psi (kph/psi).

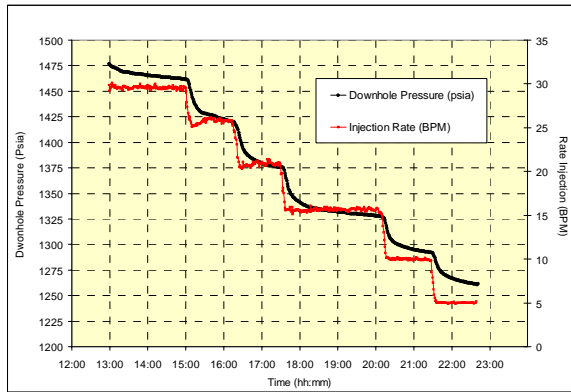


Figure-3: Measured pressure at 5500 ft and water injection rate vs. time on the 1st injectivity test.

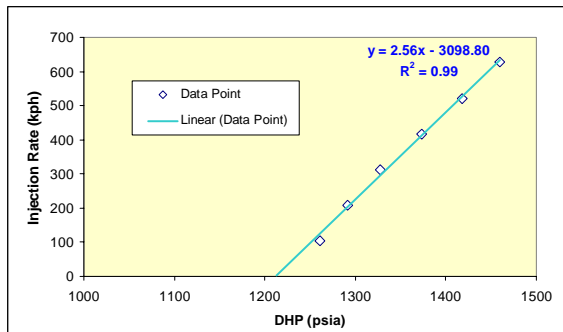


Figure-4: Plot of injection rate vs. measured pressure at 5500 ft. Initial II of Awi 8-7 was 2.56 kph/psi

2.4. Pressure Fall Off Test

After the injectivity test was completed, the water injection rate was increased to 30 BPM and maintained at this rate for five hours as preparation for the PFO test. On the PFO test, pressure decline subsequent to the closure of water injection was measured (Figure-5). The data were analyzed with automated type curve matching (Horne, 1995) using a pressure transient analysis software package called Automate (v.1999.1) to evaluate the permeability-thickness (kh) and the skin of the well. The fluid properties used in the analysis were those of the injected fluid. Homogeneous reservoir and radial flow were chosen for the model. A general fit using kh of 252,000 md-ft and skin of +2.2 resulted in a good match as shown in Figure-6 and Figure-7. This kh value indicated that Awi 8-7 has good connectivity to the natural fracture network but the effect of positive skin has created a lower permeability segment adjacent to the wellbore that

gives an additional resistance to the flow of reservoir fluids.

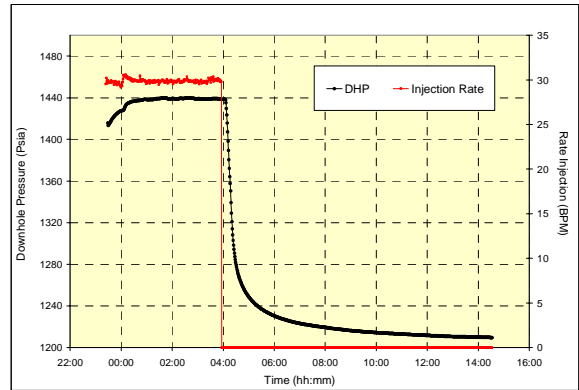


Figure-5: Measured pressure at 5500 ft and water injection rate vs. time on the 1st PFO test

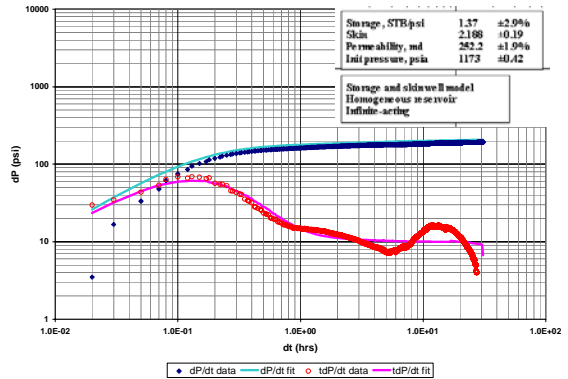


Figure-6: Derivative plot from the 1st PFO test

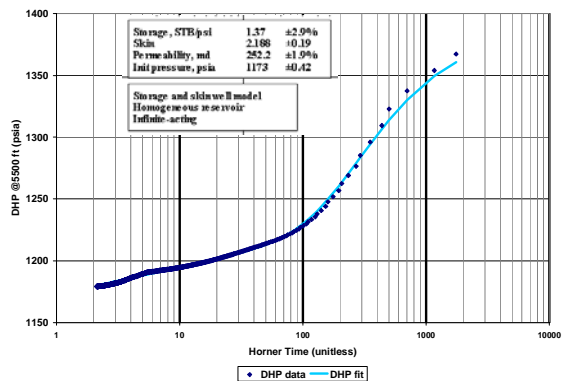


Figure-7: Horner plot from the 1st PFO test

2.5. Flow Performance Test

The first flow performance test (FPT) at Awi 8-7 was conducted before acid stimulation 120 days after drilling completion. Awi 8-7 is a liquid dominated well so that the discharge initiation required air compression of 400 psig. The test was conducted by discharging the well with different valve openings and measuring the wellhead pressure, steam and brine flow rates. The obtained data were fitted with a

parabolic equation. Figure-8 shows the measured data and the interpolated output curve.

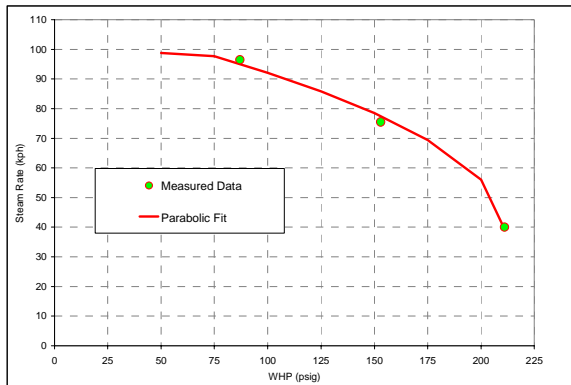


Figure-8: Discharge test data and interpolated output curve from the Awi 8-7 flow test

3. ACID TREATMENT

3.1 Acid Treatment Design

The formation damage inferred from the completion test was believed to be caused by the mechanism of drill cuttings and 94,500 bbls of water-based mud invasion. Weighting material of the drilling mud was bentonite clay and the major components of drill cuttings were quartz, tuff and feldspars. Those materials are all soluble in hydrofluoric acid (HF) to various extents. Based on this information, Awi 8-7 well was selected as a candidate for acid stimulation.

3.2 Selected HF Acid System and Volume

Hydrofluoric acid is commonly used to stimulate sandstone formations in the oil and gas industry and has also been applied in geothermal fields. The treatment chosen for Awi 8-7 utilized an HF acid system offered by BJ Services that is known as Sandstone Acid.

Sandstone Acid was chosen for the following reasons (Malate and Di Lullo, 1998):

- The mechanism of hydrogen ion disassociation results in greater depth of penetration. The Sandstone Acid system uses a phosphonic acid complex known as HV acid to hydrolyze fluoride salts. The fluoride salts are placed in the treatment fluid as either ammonium fluoride liquid (AF) or ammonium bifluoride (ABF) powder. The phosphonic acid complex has five hydrogen ions available that disassociate at different stoichiometric conditions. Having hydrogen ions released at different stoichiometric conditions means initially only a fraction of the available HF acid is produced. As this is

consumed, the reaction equilibrium shifts, generating more HF. This delays HF production offering deeper live acid penetration.

- The acid system partially reacts with clays. On contact with clays in the formation, a microfilm coating of aluminum silicate phosphonate compound is deposited. The film is resistant to HF acid attack. Being resistant to HF acid, it acts to divert live HF acid away from clays and deeper into the formation. Quartz dissolution is also improved resulting in greater acid penetration. This action also has the benefit of reducing the potential of insoluble compounds that can be produced in HF acid - clay reactions.
- The acid system has greater quartz solubility. The HV acid has good adsorption and water wetting properties that catalyze HF reactions to quartz. This action results in higher quartz solubility in time versus conventional mud acid.
- The system requires less hydrochloric acid (HCl). Because the system obtains the necessary hydrogen ions from the HV acid, a smaller volume of HCl is necessary for the preparation of hydrofluoric acid compared to regular mud acid systems. By utilizing less raw HCl, Health Safety and Environment issues are improved.

The acid treatment was designed with a load of 45 gallons of 7.5% wt. HCl per linear foot for the pre-flush and 90 gallons of 5% wt. Sandstone Acid per linear foot for the main flush. HCl preflush is first placed in the zone of interest to remove calcium carbonate, iron carbonate or other calcareous minerals. Calcareous materials can form damaging precipitates when reacting with HF acid. In addition to removing calcareous materials, the preflush moves formation brine out of the near wellbore area. Contact between formation brine and HF acid systems can also result in damaging precipitates.

3.3 Temperature Considerations

The reservoir temperature in Awi 8-7 is over 500°F, whereas standard acid inhibitors for HCl are only effective up to about 300°F. Acid inhibition for zones above this temperature is in principle possible with organic systems, but the cost goes up considerably. In the case of Awi 8-7, the well was quenched with 30 bpm of fresh water for 48 hours prior to the coiled tubing running in the hole. The quenching cools the well, however knowing the magnitude of the cooling was essential for correct design of the corrosion inhibitor loadings.

The first coiled tubing run in the hole was a temperature survey run and dummy run to confirm no obstructions in the well bore. The temperature survey consisted of a memory operated temperature probe

installed in the bottom hole assembly. The acid treatment at deepest feedzone was simulated by pumping water at rates expected during the actual job. The result of this was a maximum recorded temperature of 208°F. The temperature survey results allowed a safe reduction in corrosion inhibitor loadings from the original plan. The understanding of downhole temperatures under actual treatment conditions translated to a significant reduction in corrosion inhibition cost.

3.4 Targeting the Feed Zones

The target intervals for acid stimulation were determined from the permeable zones identified from pre-acid PTS survey. Invasion of unbroken viscosified gel filter cake on the formation face was also considered in designing the acid job (Kalfayan, 2000). The PTS survey will not be able to identify feed zones damaged by this mechanism. Therefore, the potential feed-zone locations identified from drilling breaks, drilling lost circulation, and projection from feed-zone location of surrounding wells were also considered as target intervals for acid treatment (see Table-2).

Table-2: Target intervals for acid stimulation at Awi 8-7

No	Depth (ft MD)	Interval (ft)	Remarks
1	4020 - 4070	50	Identified based on drilling loss circulation
2	4390 - 4510	120	Identified from PTS survey and feed zone location at surrounding well (Awi 8-5)
3	5350 - 5480	130	Identified from PTS survey, total loss circulation while drilling and feed zone location of adjacent well (Awi 8-6)
4	5620 - 5670	50	Identified from drilling breaks and feed zone location of adjacent well (Awi 8-6)
5	5730 - 5870	140	Identified from PTS survey
6	6150 - 6350	200	Identified from PTS survey and Drilling breaks

Coiled tubing offers advantages to place the acid via a dedicated conduit adjacent the desired zones of interest (Mitchell and Stemberger, 2003). A two-inch coiled tubing unit was utilized to maximize acid pumping rates and decrease total treatment time.

The treatment consisted of placing the Sandstone Acid and preflush across six discrete intervals totaling 690 ft of net pay over an open hole interval of 2,330 ft. The coiled tubing was reciprocated across each interval. On the first downward pass, the preflush was pumped. This was followed by reciprocating up and down with the Sandstone Acid. The overflush of fresh water was pumped while moving to the next zone of interest, with additional

overflush fresh water pumped down the annulus to aid in cooling the wellbore.

3.5 Acid Preparation

The total treatment volume was 2218 bbls of mixed acid. This volume of acid required a large number of tanks. The area of operations is in the midst of pristine forest, making protection from environmental hazards very important. To minimize the tank volumes on location, a continuous batch mixing system was employed. This entailed setting up six tanks of 125 bbls each. The treatment was started with all tanks full of mixed acid. Once a tank was emptied, it would be prepared again while the others were being utilized. The procedure was made easier by using all liquid additives for the mixed acid preparation.

Given the large treatment fluid volume, the job time would be quite long. As to maximize personnel safety it was also desired to pump the treatment during day light hours, the treatment was performed over two operational days.

A future operational enhancement would be to meter the acid additives, water and raw acid in such a way to allow continuous mixing and pumping on the fly (Di Lulo and Rae, 2002). This can be done using customized blending / proportioning units to prepare the mixed acid. The unit would only require a source of fresh water since 70 – 90% of all mixed geothermal acid systems are water. This improvement would eliminate the personnel hazard of mixing acid, eliminate the need to mix large quantities of acid prior to commencing a treatment and decrease the operational time necessary for a treatment.

3.6 Acid Treatment

The acid stimulation was subdivided into two phases (lower and upper wellbore sections) over a two-day operation. In the first phase of treatment, the acid was pumped to the two deepest intervals with a total treatment interval of 340 ft. The acid was pumped at an average rate of 4.5 bpm through the coiled tubing. After that, 20 bpm of cold water was pumped down the annulus while pulling up the coil tubing to the next treatment zone.

During the preparation of the remaining acid volume, the well was quenched with 20 bpm of cold water. On the second phase of the treatment, acid was pumped to the three shallowest intervals with a total treatment interval of 350 ft. At the end of treatment, the acid was displaced using fresh water. The tanks were filled one-fourth with a soda ash solution to neutralize them and the fluid was pumped to the well after the water displacement.

4. STIMULATION RESULTS

A post-acidizing injection test that consisted of multi-rate injection test, pressure fall-off test, and injection PTS survey was conducted to measure the wellbore improvement from the acid stimulation. As can be seen on Figure-9, a significant reduction in down-hole pressure at corresponding injection rates was observed during the multi-rate injection test after the acid job. The test confirmed an increase of injectivity index from 2.56 to 6.6 kph/psi. Analysis of the pressure fall-off data showed that the permeability thickness (kh) increased from 252,000 to 403,000 md-ft. and the skin decreased from +2.2 to -1.2 (see Figure-10). Such results are clear indications of better acceptance and reduced restriction to fluid flow.

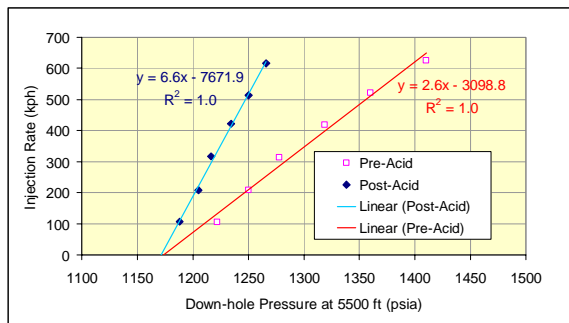


Figure-9: Plot of injection rate vs. measured pressure. II of Awi 8-7 has increased from 2.6 (before acid job) to 6.6 kph/psi

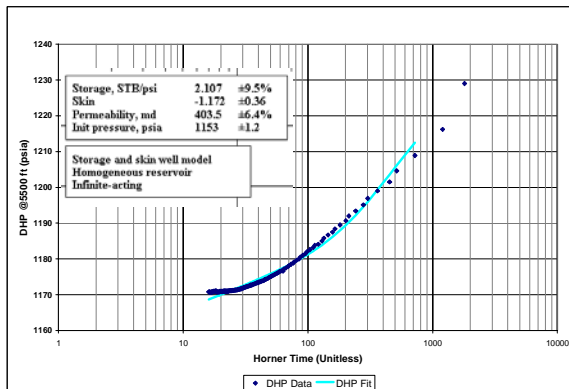


Figure-10: Horner plot from the PFO test after acid job

Table-3: Entry locations and II distributions identified from post-acid injection PTS survey

Entry Depth (ft-MD)	II Pre-Acidizing (kph/psi)	II Post-Acidizing (kph/psi)	Δ II (kph/psi)
4400	0.82	2.84	2.02
5380	0.60	1.73	1.13
5800	0.26	0.35	0.09
6250	0.53	0.84	0.31
6310	0.34	0.79	0.45

Entry locations identified from the injection PTS survey are the same as those identified from the pre-acidizing survey. This suggests that formation damage due to unbroken gel filter cake did not exist on the formation face. A PTS analysis with the wellbore simulator revealed an improvement of injectivity of each entry (see Table-3).

The final and most important gauge of wellbore improvement is the steam deliverability of the well. A flow performance test conducted after acidizing showed a remarkable improvement in power output. The maximum discharge pressure (MDP) increased from 211 to 297 psig and the steam production at commercial wellhead pressure of 150 psig increased from 70 (4.2 MWe) to 162 kph (9.8 MWe).

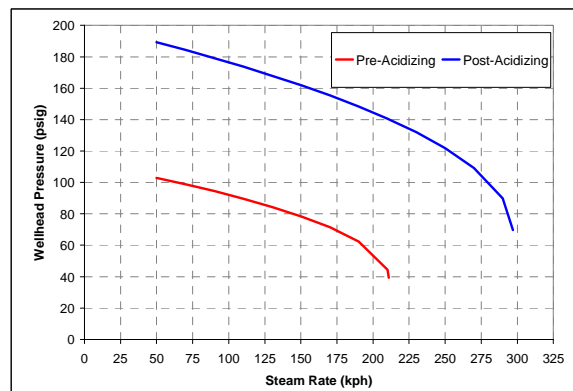


Figure-10: Awi 8-7 deliverability curves, before and after acidizing.

5. CONCLUSION

An acid treatment using Sandstone Acid was carried out to improve the production characteristics of a geothermal well in the Salak geothermal field following an accurate analysis of the possible causes for the initial poor performance of the well. The acid was placed to the target interval zone with a two-inch coiled tubing unit to maximize control over the treatment. Well test results before and after stimulation demonstrate that the acid stimulation has successfully produced improvements in overall well characteristics such as reduction of skin, increase of injectivity and permeability-thickness product, and production output. Based on the positive results obtained in this case, further application of this method is envisaged for other poor-performing wells with similar characteristics.

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