WELL INTERVENTION AND ENHANCEMENT IN DIENG GEOTHERMAL FIELD, INDONESIA

Ichwan Agusta Elfajrie[1]*, Stefanus Kusuma Adityawan[1], Luthfan Hafizha Judawisastra[1], Muhammad Istiawan Nurpratama[1], Dodi Herman[1] and Ramonchito Cedric M. Malate[2]

[1]PT Geo Dipa Energi (Persero) Aldevco Octagon 2nd Floor, Jl. Warung Jati Barat No. 75, South Jakarta 12740 - Indonesia

[2]KDA Consulting Limited, 1 Pepene Avenue, Waiata Shores, Conifer Grove, Auckland 2112, New Zealand

*ichwan@geodipa.co.id

Keywords: *Dieng, well enhancement, acid stimulation*

ABSTRACT

PT Geo Dipa Energi, (Persero) started developing Dieng Geothermal Field in 2002 and has since implemented operational strategies to sustain steam supply to the installed plant capacity of 60 MWe. Periodically, the company conducted a candidate selection and prioritization of the wells for well workover and enhancement to address steam supply and injection capacity shortfall. The results of evaluation formed the basis in implementing a well intervention and acid stimulation campaign for the prioritized candidate production and injection wells in Dieng Geothermal Field. Improvements were initiated in terms of well testing and analyses and acid treatment design to increase the effectiveness of the well stimulation. The use of electronic pressure-temperature-spinner logs and improved well test interpretation became essential for better candidate selection, acid treatment design, quantification of pre-acidizing well parameters and evaluation of acidizing results. To date, acid stimulation program has been successfully implemented in three production wells and two injection wells. Considerable improvement in production and injection capacities of these wells were attained that improved the operational level of the power plant in Dieng Geothermal Field.

1. INTRODUCTION

1.1 Background

Dieng Geothermal Working Area which is located in Central Java Province, Java Island, Indonesia, is one of the geothermal fields operated by PT Geo Dipa Energi (Persero) (GDE) since 2002 with an electricity generation capacity of 60 MWe (Figure 1).

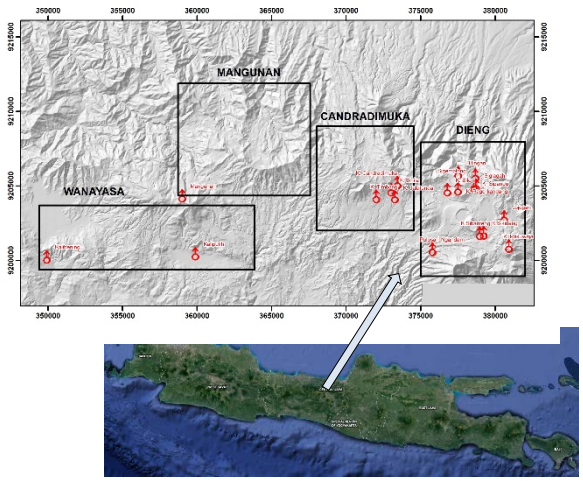


Figure 1: Location of Dieng Geothermal Working Area.

To date, a number of well intervention programs have been performed to address production and injection capacity decline due to wellbore or reservoir problems. Wellbore problems are closely related to well clearance and casing integrity issues. Meanwhile, reservoir problems are related to the changes of reservoir performance capability, specifically feed zone contribution decline due to positive skin in the form of mineral deposition such as scale, mud cake or cutting during drilling. Figure 2 shows well intervention types for each wellbore and reservoir issue (Sarmiento, 2008).

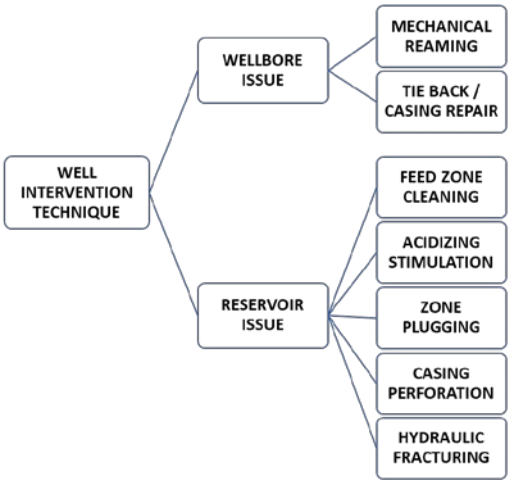


Figure 2: Well intervention techniques (Sarmiento, 2008).

Besides mechanical reaming and tie back/casing repair technique, acid stimulation has been conducted in several production and injection wells in Dieng geothermal field since 2019. Matrix acidizing was implemented rather than fracture acidizing and the acid was injected using diffuser (perforated drill pipe) in front of target feed zone.

1.2 Matrix Acidizing

Matrix acidizing is an acid stimulation method where the acid solution is pumped to increase permeability near the wellbore by removing damage or filter cake in the feed zone area. It is pumped with less pressure than fracturing pressure so that the acid can penetrate further into formation (poro-elastic concept) in certain range of penetration. By a number of experiences, it is estimated to 3-3.6 m of maximum range of penetration (Malate, 2003).

Important factors in designing matrix acidizing stimulation are:

- Damage type (mud, scale, etc.)
- Cutting or scale sample solubility to acid system
- Formation type of near wellbore
- Estimated feed zone thickness

In general, there are four stages in acid stimulation process:

a. Preflush, usually using HCl. It is aimed to remove Ca^{2+} and CO_3^{2-} in the formation. Its purpose is to optimize acid mainflush reaction afterward. Brine or fresh water is not recommended as preflush fluids because HF can react with metal ions in the solution to form insoluble precipitates.
b. Mainflush, HCl and HF compound in certain ratios. HCl can dissolve limestone or dolomite. It is not effective to dissolve silica mineral such as clay, feldspar and silica sand. In contrast, HF can dissolve silica mineral effectively. However, HF is not effective to dissolve carbonates because its reaction can form an insoluble precipitate such as CaF_2.
c. Overflush, either HCl, KCl, NH_4Cl or freshwater. It is intended to push byproducts produced by the mainflush reaction away from wellbore. The use of 5% NH_4Cl is to reduce the chance of secondary product precipitation which causes formation damage. Overflush volume is at least equal to mainflush volume.
d. Displacement, usually using fresh water. It is intended to clean drill pipe from acid solution before lifting the diffuser to another pumping target.

For the preflush acid system, HCl with a range of 10-15% is most often used. For the mainflush acid system, it generally ranges from 10%HCl:7%HF to 12%HCl:3%HF. Based on PNOC-EDC experience in Philippines, mainflush ratio of 10%HCl:5%HF can be used as a basis system in solubility test (Malate, 2003). Table 1 can be used as a guidance to estimate the effectiveness of solubility of certain minerals to HCl and HCl:HF (Portier, André, & Vuataz, 2007). The cleaner the formation and the higher the permeability, the lower HCl:HF ratio can be. High HF concentration in mainflush acid system, e.g. 10%HCl:7%HF, can be used for formation with high silica content.

MINERALS	SOLUBILITY	
	HCl	HCl-HF
Quartz	No	Very low
Felspars	No	Low to moderate
Micas	No	Low to moderate
Kaolinite	No	High
Illite	No	High
Smectite	No	High
Chlorite	Low to moderate	High
Calcite	High	High, but CaF_2 precipitation
Dolomite	High	High
Ankerite	High	High
Siderite	High	High

Table 1: Solubility of sandstone minerals (Portier, André, & Vuataz, 2007).

The acid performance can be evaluated by performing solubility test of cutting or scale sample to several acid system. Based on GDE experience, a 50% total solubility of preflush and mainflush acid is considered good for acid stimulation.

Each preflush and mainflush acid volume is determined based on the estimated feedzone thickness. The reference acid volume ratio for Dieng geothermal fields is 50 gal/ft for preflush and 75 gal/ft for mainflush. The mainflush volume of 75-125 gal/ft has a success ratio of 75%, while those with less than 75 gal/ft only have a success ratio of 30% (Malate, 2003). The use of acid volumes greater than 200 gal/ft has a very high success ratio but also has a high cost. Acid system can be optimized following the actual feedzone thickness according to PTS logging results. Preflush acid volume can be optimized to 75 gal/ft and 100 gal/ft. Therefore, the results of solubility test and the budget availability are two important factors to influence the selection of acid system and its volume ratio.

The next important lab tests are corrosion test and water compatibility test. The purpose of corrosion test is to ensure that the acid composition will not damage materials, such as drill pipe and casing or liner. The allowable corrosion rate (ACR) of material by an acid system is established at 0.05 lbs/ft^2. The test is conducted for 12 hours at 100ºC at minimum temperature (boiling point at atmospheric pressure). Water compatibility test is intended to ensure that the acid dilution in specific fresh water will not form sludge.

Figure 3 shows flowchart of matrix acidizing preparation.

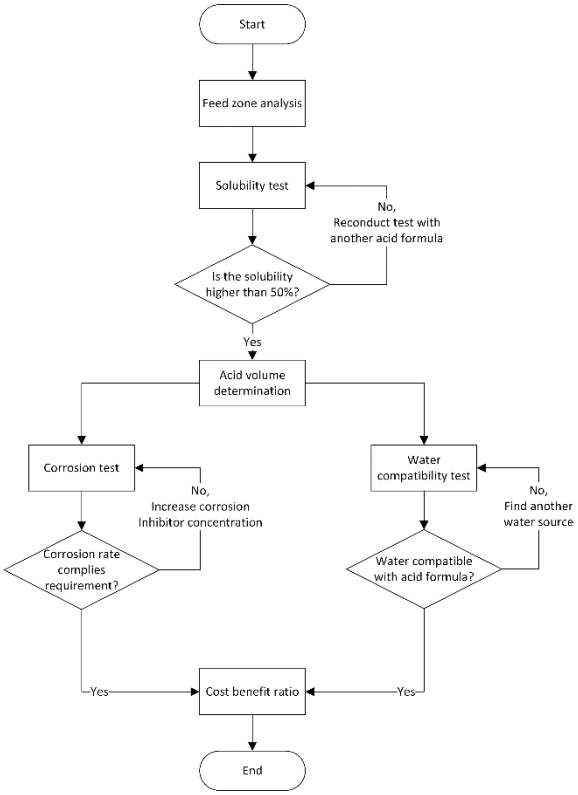


Figure 3: Flowchart of matrix acidizing preparation.

1.3 Diffuser Design

The acid was injected through a diffuser to improve the acid penetration to the perforated liner and formation. The acid is pumped at target rate of 14 bpm.

The diffuser has 9.42 m of length with 3.5 inches of diameter. Twenty-seven (27) perforation holes with 0.5 inch and 0.75 inch of diameter has been installed following 60 degrees of

distribution angle. Figure 4 (a-b) shows the diffuser and Figure 5 is an illustration of acid pumping inside the liner.



(a) (b)

Figure 4 (a-b): (a) Actual diffuser condition, (b) An example of fluid pumping during function test on surface.

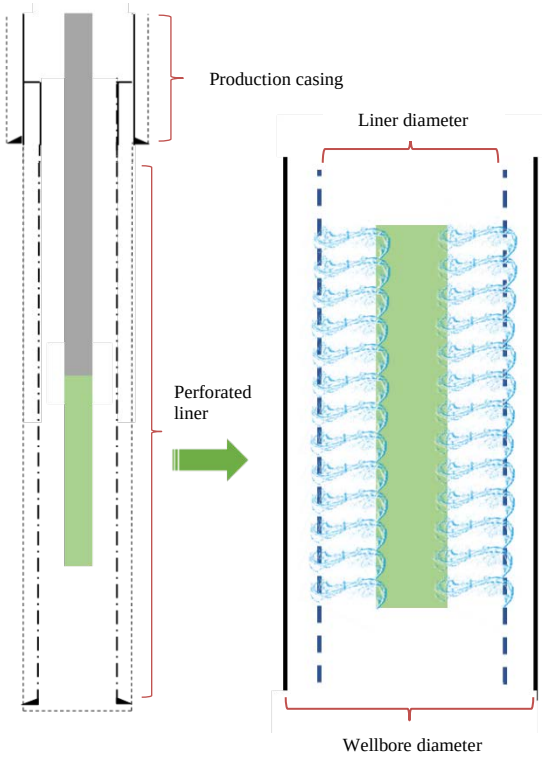


Figure 5: Illustration of acid pumping inside liner.

2. GDE ACID STIMULATION PROGRAM

The matrix acidizing stimulation job starts with work over mechanical reaming activity to optimize access to target pumping depth. A pre-acid PTS logging survey in injection condition follows to confirm estimated feed zone location and thickness before chemical mixing. A mandatory quality control to acid system is conducted by checking its SG value to ensure consistency prior to acid pumping. Table 2 shows the SG reference of common acid formula.

ACID SYSTEM	SG LAB BLEND
10% HCl	1.047
10%:5% HCl:HF	1.092
10%:7% HCl:HF	1.112
5% NH_4Cl	1.016

Table 2: SG value reference.

After acid treatment is successfully completed, a post-acid PTS logging survey in injection condition is performed to determine gain in Injectivity Index (II) for each feed zone. It provides a preliminary result of acid stimulation, both on production capacity and injection capacity enhancement. Both PTS logging survey are followed by injectivity test at varying injection rates to measure improvement from acid treatment. Figure 6 shows a total flow chart of the entire acid stimulation program.

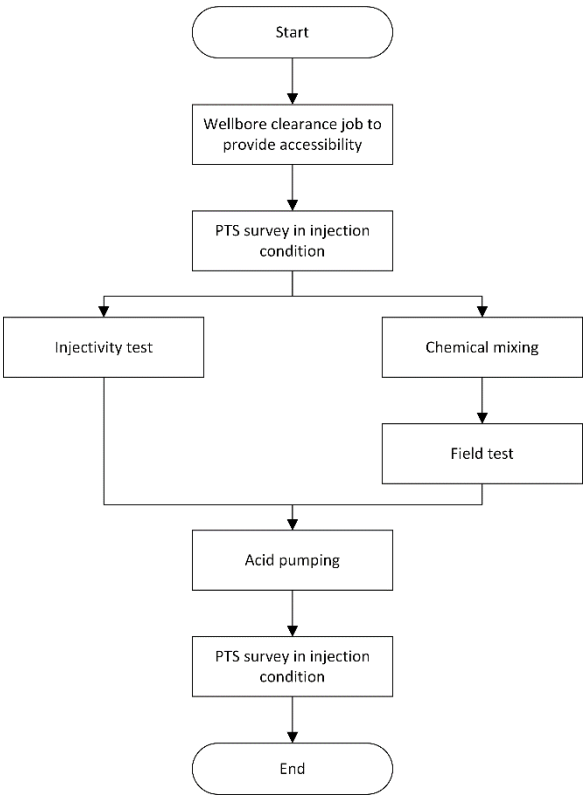


Figure 6: Flowchart of entire acidizing program.

There were two injection wells that have been stimulated in 2019 namely, DNG-A and HCE-A. Both injection wells were decommissioned since 2017 due to injection capacity decline. In the following year (2020), acid stimulation was performed in three production wells: HCE-B, HCE-C, and HCE-D. Work over mechanical reaming and tie back casing have been done before to these production wells, but well productions were still not as good as expected.

In injection wells stimulation program, pre and post acid PTS logging survey were not conducted. As a replacement, GDE conducted a pre and post surface injection test to gauge the injection capacity improvement after stimulation.

3. ACID STIMULATION RESULTS

3.1 Injection Wells

3.1.1 Preparation

Supersaturated silica brine (SSI>>100%) have been continuously pumped out of settling ponds into the Dieng injection wells throughout the operation of the power plant. As such, silica deposition was observed in these injection wells that produced blockages and eventually led to decline in injection capacities. Work over mechanical reaming and acid stimulation have been conducted to increase injection capacity of two injection wells, DNG-A and HCE-A in the beginning of 2019 with the following objectives:

a. To clear the silica mineral blockages detected in the wellbore.
b. To improve the current injection capacity of the wells by removing near well skin (formation damage) through acid treatment.
c. To improve the permeability in the immediate vicinity of the wellbore.

The initial acid system proposed for injection wells DNG-A and HCE-A is the application of 15% HCl preflush and 10%HCl:7%HF mainflush. The solubility test was also conducted by using 15%HCl preflush and proposed mainflush at 12%HCl-7%HF and 15%HCl-7%HF concentrations (Table 3).

WELL	% SOLUBILITY				
	15% HCl	10%:7% HCl:HF	12%:7% HCl:HF	15%:7% HCl:HF	TOTAL
HCE-A	14.09	67.43	-	-	81.52
		-	67.67	-	81.76
		-	-	64.80	81.79
DNG-A	7.09	57.44	-	-	64.53
		-	56.17	-	63.26
		-		60.12	67.21

Table 3: Solubility test results of HCE-A and DNG-A.

Acid solubility of HCE-A scale samples were found to be very high compared to DNG-A acid solubility results which is also considered to be well above the usual average solubility results. Mainflush system 10%HCl:7%HF was selected because the solubility test result is not much different with the other two acid systems.

The permeable zones detected in DNG-A are 1,738-1,806 mMD and 1,809-1,940 mMD with estimated total feed zone thickness of around 200 m. These were mainly based on observed partial drilling loss records. It was decided to cover 25% of total feed zone or only about 50 m. The acid job design proposed for DNG-A called for acid volumes of:

- Preflush 15% HCl volume = 300 bbls
- Mainflush 10%HCl-7%HF volume = 300 bbls

The only permeable zone detected in HCE-A at 2,043-2,050 mMD was based on the observed total loss drilling record and temperature heating up survey. This gives a total feed zone thickness of only 7 m. The calculated acid volumes would be very small if the feed zone thickness of 7 m will be used. Further, it was decided to expand total pumping target thickness to 40 m. The acid job design proposed for HCE-A called for acid volumes of:

- Preflush 15% HCl volume = 250 bbls
- Mainflush 10%HCl-7%HF volume = 250 bbls

3.1.2 Results

GDE conducted a pre and post surface injection test to gauge the improvement after stimulation. An injection capacity model calculation for DNG-A and HCE-A is presented using available information:

a. Injectivity of the well
b. Permeable zone location/s
c. Reservoir pressure at the feed zone

The calculation procedure for injection capacity starts from bottom to wellhead, with the bottom set at the depth of the deepest feed zone. The principal calculation methodology is based on pressure drop calculation derived from Bernoulli's fluid flow equation:

$$\frac{dP}{dz} = \frac{g}{g_c}\rho\cos\theta + \frac{f\,\rho\,v^2}{2\,g_c\,d} + \frac{\rho\,v\,dv}{g_c\,dz}$$

where:

dP/dz: pressure drop per certain depth, bar/m
g: gravitational constant, 9.81 m/s^2
g_c: gravitational conversion constant
ρ: fluid density, kg/m^3
θ: inclination angle
f: friction factor
v: fluid velocity, m/s
d: casing or liner diameter, m

The pre-acid injection test conducted on DNG-A at maximum injection rate of 228 tph showed a small positive WHP at approximately ~2.7 barg. The post acid injection test conducted at higher injection rate of 304 tph gave vacuum WHP readings (-0.7 barg). Figure 7 below shows the DNG-A injection test results.

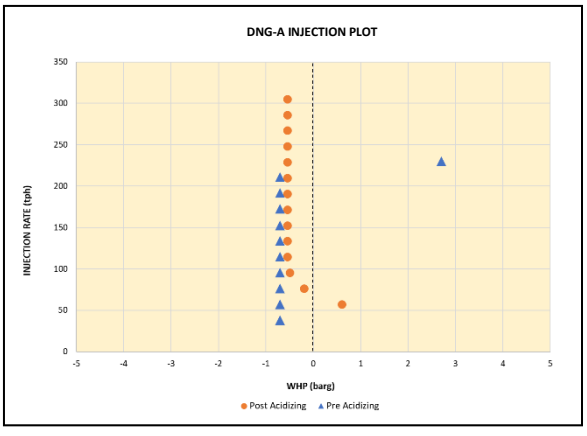


Figure 7: DNG-A pre and post acid surface injection test.

The pre-acid cold injection capacity of DNG-A against wellhead delivery pressure is presented in Figure 8. Here, the injectivity index of the well was initially varied to calibrate the injection model. The injection model with an injectivity of about 4.3 tph/bar and reservoir pressure of ~140 bara gave

a good match to the observed injection capacity at 2.7 barg. A pre-acid cold injection capacity (T=25°C) of about 220 tph at zero WHP is then calculated. This corresponds to a static water level of about ~522 m.

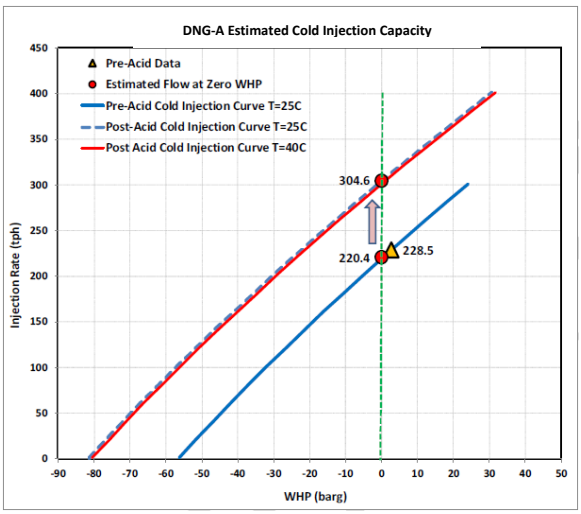


Figure 8: DNG-A pre and post acid estimated injection capacity.

The post-acid cold injection capacity was also modelled using the same injectivity index at 4.3 tph/bar and a pressure reduction of at least ΔP~20 bars which corresponds to a decline in static water of at least 200 m. The post-acid injection capacity at injection temperature of 40°C is estimated by applying the fluid density correction which is also displayed in Figure 8. Around 40% improvement in injection capacity is realized at the targeted brine injection condition.

Figure 9 below shows the HCE-A surface injection test results. The pre-acid injection test conducted at maximum injection rate at 304 tph showed vacuum WHP. The post-acid injection test also conducted at 304 tph gave similar vacuum WHP readings (-0.6 barg).

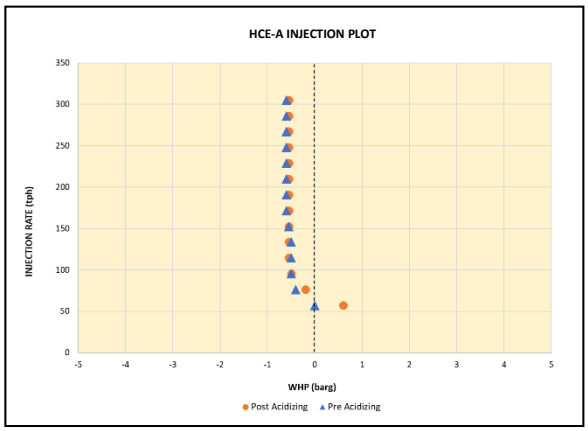


Figure 9: HCE-A pre and post acid surface injection test.

The surface injection tests showed the well could easily accept 50 tph brine with vacuum WHP whereas HCE-A could not operate before. The improvement of injection capacity is difficult to be determined since the well response was similar before and after acid stimulation. Therefore, the total gain of injection capacity was approach by using the conservative number of initial and final injection rate capacity. It is assumed the well can accept at least 100 tph brine at zero WHP before acid stimulation. The estimated pre-acid injection capacity curve is presented in Figure 10 with the calibrated injectivity index of 7.5 tph/bar and reservoir pressure of at least 170 bara.

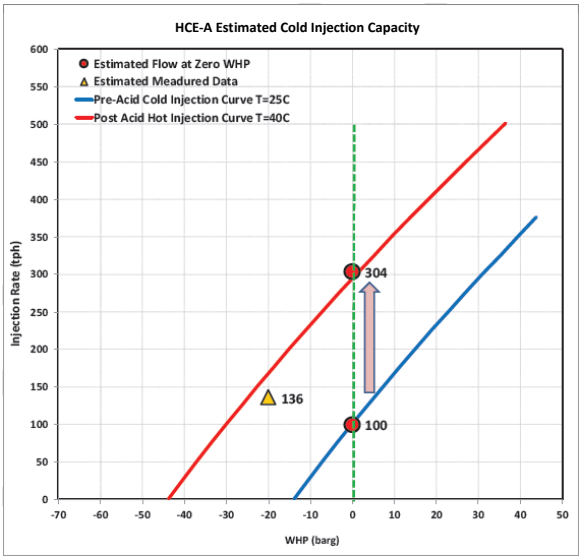


Figure 10: HCE-A pre and post acid estimated injection capacity.

It is also further assumed that the well can easily accept 340 tph of brine at zero WHP after acid treatment. The post-acid injection capacity curve is estimated using the same injectivity at 7.5 tph/bar and pressure reduction of at least ΔP ~ 25 bars. This would correspond to a decline in water level of more than 200 m. A 240% improvement in injection capacity is realized at the targeted brine injection condition.

3.2 Production Well

3.2.1 Preparation

To optimize steam production for Dieng Unit 1, acid stimulation was performed in three production wells: HCE-B, HCE-C and HCE-D in early 2020. Based on well deliverability curve, the total expected gain of steam production was 5.8 MW.

Solubility test to all the samples gave very good results, which is way higher than 40% (77-85%). A chemical component of preflush and mainflush is very effective and satisfying. Table 4 shows the solubility test detail.

WELL	DEPTH SAMPLE (m)	SOLUBILITY (%) TO PF & MF ACID SYSTEM			
		PF (10% HCl)	MF (10%:5% HCl:HF)	MF (10%:7% HCl:HF)	TOTAL
HCE-B	1,770	16.40	65.79	-	82.19
	1,980	21.35	58.04	-	79.39
HCE-C	1,926	20.25	-	63.92	84.17
	2,115	20.88	-	62.75	83.62
	2,151	17.33	-	68.00	85.33
HCE-D	1,935	23.23	-	53.36	76.58
	1,959	23.23	-	60.73	83.95
	1,992	21.20	-	55.91	77.11

Table 4: Solubility test results of HCE-B, HCE-C and HCE-D.

The acid volume was determined using the dosing rate of 75 gal/ft for mainflush and 50 gal/ft for preflush, after determining the total thickness of feed zone targets. A 5% NH_4Cl was selected as overflush to avoid mineral precipitation with 8 ft of depth of penetration (critical depth of penetration is 3 ft). The initial acid mixture volume requirements for each well are summarized in Table 5.

WELL	PUMPING TARGET THICKNESS (m)	VOLUME ACID (barrel)		
		PREFLUSH	MAIN FLUSH	OVER FLUSH
HCE-B	120	494	728	729
HCE-C	60	260	377	377
HCE-D	80	338	494	495

Table 5: Acid volume requirements of HCE-B, -C and -D.

Water compatibility test shows there was no sludge formation, so that the available water source was compatible with acid system. Corrosion tests to drill pipe and casing samples show good result where the observed corrosion rate was below ACR (Table 6).

ACID SYSTEM	CORROSION RATE (lbs/ft^2)	
	DRILL PIPE	CASING
10% HCl	0.00316	0.0235
10%:5% HCl:HF	0.01623	0.0288
10%:7% HCl:HF	0.04820	0.0313

Table 6: Corrosion test results.

The acid mixture volume requirements were then updated based on the results of the pre-acid PTS logging survey. Table 7 shows the updated feed zone thickness targets and acid mixture volume of each well.

WELL	PUMPING TARGET THICKNESS (m)	VOLUME ACID (barrel)		
		PREFLUSH	MAIN FLUSH	OVER FLUSH
HCE-B	40	325	700	700
HCE-C	50	300	400	350
HCE-D	80	450	670	670

Table 7: Updated pumping target thickness and acid mixture volume

3.2.2 Results

Increased Injectivity Index (II) value and changes in bottom hole pressure (BHP) are indicative of well production. Tables 8-9 show the changes in injectivity for HCE-B and HCE-C. The injectivity decline observed at FZ#5 in HCE-B and FZ#1 and FZ#9 in HCE-C will be confirmed by the calculated Productivity Index (PI) value on next survey.

FEED ZONE	DEPTH (m)	II (kg/s/bar)		
		BEFORE	AFTER	GAIN (%)
FZ#5	1,757	0.45	0.09	-80
FZ#4	1,779	0.41	0.49	19
FZ#3	1,893	0.22	0.22	2
FZ#2	1,903	0.09	0.11	28
FZ#1	1,933	0.48	1.07	121
TOTAL II		**1.65**	**2.00**	**21**

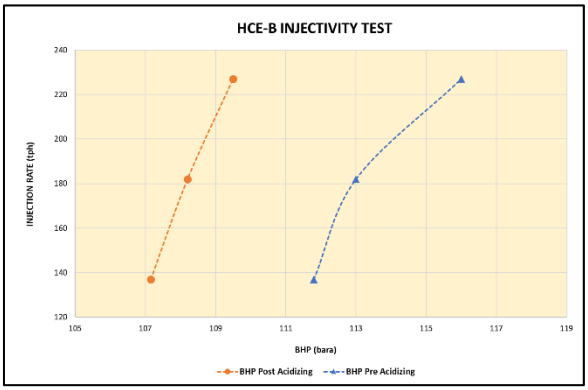
Table 8: II gain in HCE-B.

FEED ZONE	DEPTH (m)	II (kg/s/bar)		
		BEFORE	AFTER	GAIN (%)
FZ#9	1.799	0,13	0,08	-41
FZ#8	1.927	0,71	1,07	52
FZ#7	2.031	0,07	0,18	142
FZ#6	2.037	0,07	0,12	61
FZ#5	2.071	0,04	0,06	58
FZ#4	2.101	0,07	0,11	55
FZ#3	2.131	0,03	0,05	53
FZ#2	2.163	0,03	0,07	126
FZ#1	2.193	0,10	0,07	-26
TOTAL II		**1,25**	**1,81**	**44**

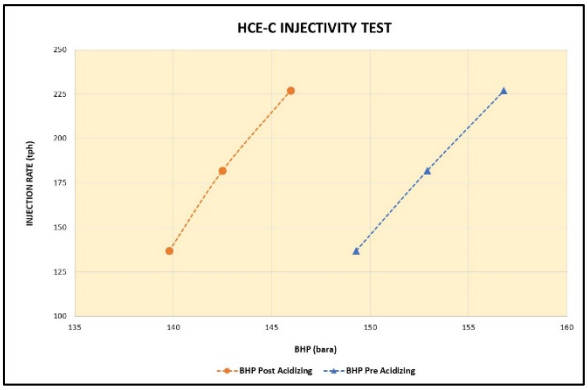
Table 9: II gain in HCE-C.

Post-acid PTS logging survey was not carried out in HCE-D because of the obstruction found during pre-acid PTS logging survey pre-acid pumping. The spinner blade stopped rotating no longer rotates due to damage on spinner casing, which only produced good data during RIH of the PTS tool. Therefore, the feed zone targets were only defined using drilling loss circulation data, such as TLC and PLC.

In addition to injectivity (II) measurement of feed zone, an Injectivity test at selected depths was also conducted for HCE-B and HCE-C at three injection rates: 137 tph, 182 tph and 227 tph (Figure 11).



(a)



(b)

Figure 11 (a-b): Injectivity test before and after acid stimulation; (a) HCE-B, (b) HCE-C

Both wells HCE-B and HCE-C produced an increase in injectivity at 21% and 44% respectively. There was a decline in BHP in HCE-B of about 5-7 bara that translated to estimated water level drop about 48-67 m. In HCE-C, BHP declined by about 10-11 bara with estimated water level drop about 96-106 m.

Well performance was evaluated two (2) weeks after HCE-B, -C and -D are back online. Operational wise, all production wells in Dieng geothermal field are operating at

minimum WHP to meet the allowable silica scaling index (SSI) value. After acid stimulation, all the three production wells can now be operated above minimum WHP (Table 10).

WELL	OPERATING WHP vs. WHP MINIMUM (SSI LEVEL)		STEAM FLOW (tph)	WELL OUTPUT (MW)
HCE-B	Before	Below	15.6	2.1
	After	Above	25.0	3.5
HCE-C	Before	Below	30.5	4.1
	After	Above	64.3	9.0
HCE-D	Before	Below	19.6	2.6
	After	Above	25.7	3.6

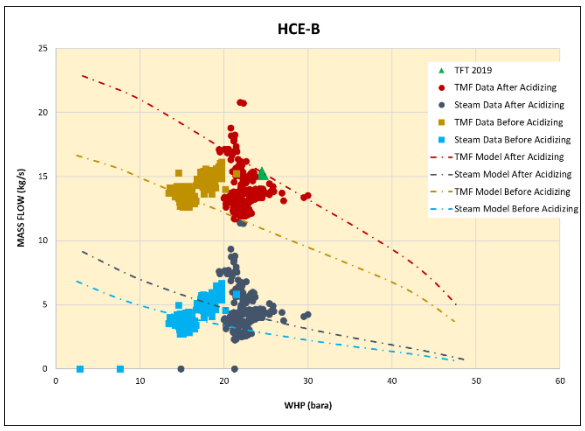
Table 10: Production performance comparison.

Table 11 shows the performance of all three wells before and after acid stimulation. The total output gain of about 7.3 MWe was higher than the initial plan estimate by 1.5 MWe.

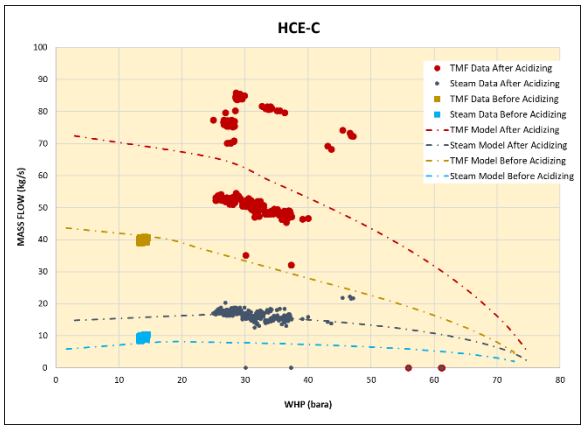
WELL	TOTAL II GAIN (%)	TOTAL OUTPUT GAIN		REMARKS
		MW	%	
HCE-B	21	1.4	67	• PF & MF Ratio: 100 gal/ft & 150 gal/ft • Moderate II gain
HCE-C	44	4.9	120	• PF & MF Ratio: 69 gal/ft & 95 gal/ft • High II gain
HCE-D	Unknown	1.0	38	• PF & MF Ratio: 69 gal/ft & 104 gal/ft • Unconfirmed FZ due to obstacle
TOTAL		7.3		

Table 11: Injectivity II and production gain.

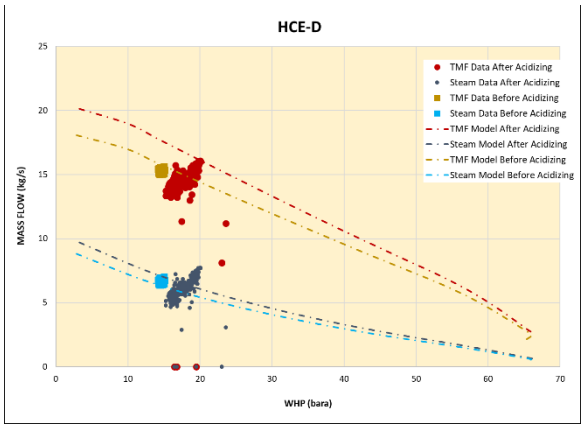
The comparison of well deliverability output curves for the three wells can be found in Figure 12 (a-c). There was considerable improvement in steam flows for HCE-B and HCE-C while minimal steam gain in HCE-D because the feed zone thickness and location were unavailable to be confirmed before acid pumping. It may lead to ineffective acid pumping. The steam gain in HCE-D was found to be about 38% only, which was confirmed by production data shown in well deliverability curve in Figure 12 (c).



(a)



(b)



(c)

Figure 12 (a-c): Injectivity test before and after acid stimulation; (a) HCE-B, (b) HCE-C

4. COST ANALYSIS

4.1 Injection Wells

The acid job cost for DNG-A and HCE-A are summarized in Figure 13 below. The cost components were categorized into mobilization-demobilization costs, equipment rental cost and materials costs. Mixing and pumping job, including personnel cost, was included into the mobilization-demobilization costs.

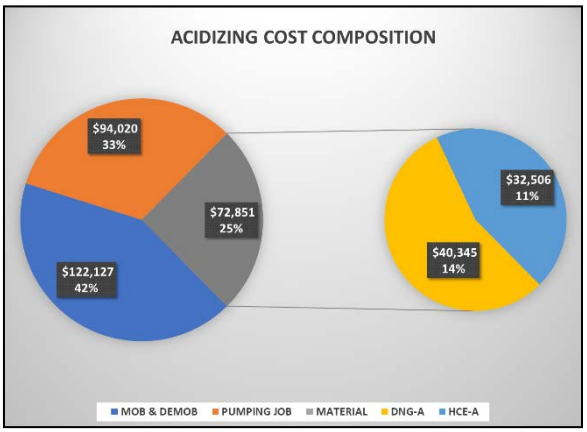


Figure 13: Cost structure of DNG-A and HCE-A acidizing stimulation

The total cost of the acid job was evaluated at US$288,999 or at around US$145,000 per well. The cost structure shows the material cost at about 25% of total cost with the mobilization-demobilization costs at 42% representing the bulk of the acid job cost.

4.2 Production Wells

Similar to injection wells, the cost structure of acid stimulation in production wells also consists of three main categories: mobilization-demobilization costs, equipment rental cost and materials cost. The cost ratio of each three category is almost similar, about one third of the total cost. The difference was an additional cost of a wellpad moving because one of the three production wells is located on a different wellpad. Figure 14 shows the production wells cost structure.

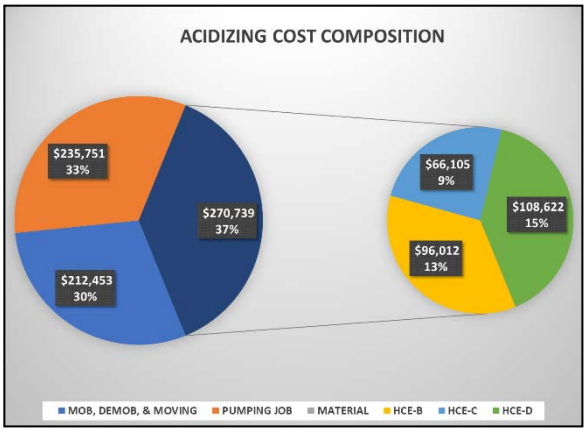


Figure 14: Cost structure of HCE-B, HCE-C and HCE-D

The acid materials cost for HCE-D was higher than others, about 15% of total materials cost. It was driven by its estimated feed zone thickness of 80 m. On average, acid materials cost per well at around US$90,000 for 170 m of total feed zone thickness. According to injection wells stimulation job in 2019, the cost of acid volume per meter feed zone thickness in 2020 was about US$300 higher regardless of the difference of acid materials. It is very essential to ensure the acid is pumped right on target. It means that PTS logging pre-acid survey is very important to conduct with a slight additional cost of about US$6,900 per survey.

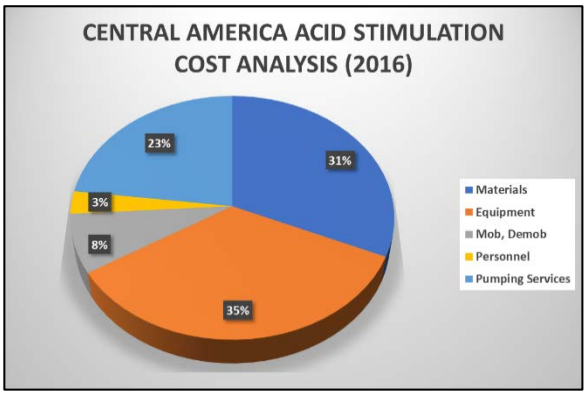


Figure 15: Acid stimulation cost structure for wells in Central America (60 m equivalent volume) (Malate,2019).

Total acid stimulation cost is estimated around US$718,942 or US$239,647 for one production well. With a total production output gain of 7.3 MW, the cost per 1 MW gain is about US$98,485.

The acid stimulation cost structure for typical wells in Central America with similar material volume requirement is presented in Figure 15 (Malate, 2019). The cost structure shows similar contribution for the materials cost at ~31% of total acid job cost and the equipment rental cost at ~35%. However, the total acid job cost at a minimum of US$650,000 per well is almost similar with GDE's project of acid stimulation for three production wells.

Performing acid stimulation using drill pipe also presents the rig services cost. In total, the composition of acid pumping is estimated at 50%, rig services at 46% and wireline services at about 4% (Figure 16). By including both rig and wireline services, the total incremental cost per 1 MW gain translates to US$195,025. It is still lower than acidizing cost budget, which about US$238,855 per 1 MW with 5.8 MW of expected gain.

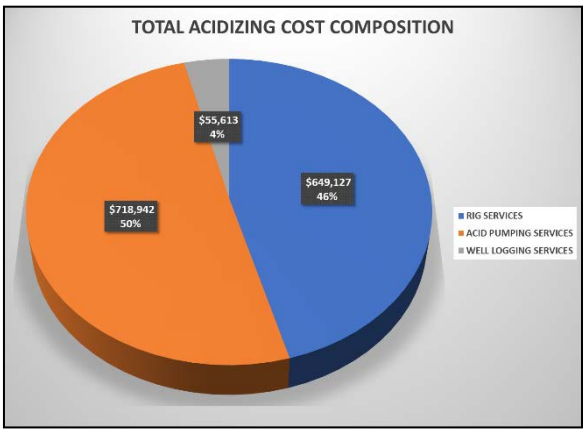


Figure 16: Total acidizing cost composition

5. CONCLUSION

Following are the conclusions of the completed acid stimulation of injection and production wells in Dieng geothermal field:

a. A good increase in injection capacity (~40%) was obtained in DNG-A while significant increase (~240%) was realized in HCE-A. The injection capacity improvement was estimated using wellbore injection model due to unavailability of downhole PTS measurements.
b. The total production output gain in three production wells exceeded the GDE expectation. The total output improvement is approximately 7.3 MW, 1.5 MW higher than the plan. After acid stimulation, all three production wells can now be operated above minimum WHP considering the SSI level.
c. HCE-B presented a 21% gain in Injectivity Index (II) and HCE-C by about 44%. PTS logging was not conducted in HCE-D due to the obstruction inside the wellbore. Therefore, feed zone position and thickness, including the II gain, could not be confirm.
d. In 2019, the total cost of acid stimulation in two injection wells was estimated at US$288,999 or at around US$145,000 per well. In 2020, the total cost of acid stimulation in three production wells was at

US$718,942 or at around US$239,647 per well. By including the cost of rig and wireline services, the total incremental cost per 1 MW output gain was calculated at US$195,025.

REFERENCES

Malate, R. C. M.: Well Intervention Techniques. *International Geothermal Conference 2003*, Reykjavík, Iceland. pp. 7 – 11. (2003).

Malate, R. C. M.: Evaluation of Dieng and Patuha Wells for Acid Stimulation. *PT Geo Dipa Energi (Persero) Internal Report*, Jakarta, Indonesia. (2019).

Portier, S., André, L., & Vuataz, F.-D. Review on Chemical Stimulation Techniques in Oil industry and Applications to Geothermal Systems. *Enhanced Geothermal Innovative Network for Europe*, pp. 11-14. (2007).

Sarmiento, Z. F. Management of Geothermal Resources in the Philippines. *Short Course on Geothermal Project Management and Development*, pp. 5-10 (2008).

ISSN 2703-4275