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Production Improvement Through Scale Removal by Condensate Injection in Darajat Geothermal Field Indonesia

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ABSTRACT

Condensate injection to remove wellbore scale and to improve production has been attempted in numerous geothermal fields including Salak, the Geysers, and others. This work describes the first condensate injection operation in the Darajat field. It was also attempted to improve on this process by injecting hot condensate and possibly increasing its pH to accelerate the dissolution of scale.

Ring gauge/go devil history of DRJ-AA indicated that scale was identified in the wellbore starting around 2008. The presence of this scale was accompanied by a higher decline in the well's production thus making this well one of the candidates for well remediation or work-over.

During the preparations to plug and abandon a power plant condensate injector, there was a need to find a temporary injector to take the condensate while engineering work was being done to transfer all condensate to an edge-field injector. This operational opportunity was then translated into a plan of removing the scale and improving production by injecting DRJ-AA with power plant condensate. This was a common practice for scaled-up wells at Salak Field, another Chevron-operated geothermal facility in West Java. The process was to be improved by heating up the condensate using the same well's steam. This was proposed to be done using a positive displacement (PD) pump, injecting at a rate in which there is still positive well head pressure (around 3-5 barg). In concept, the steam from the reservoir pre-heats the condensate before it reaches the shallowest scale detected in the well, which is above the top of the liner. This remedial well work was executed in two stages, namely, a short-period (8 hours) "hot condensate" injection stage by utilizing PD pumps and a long-period (~2 months) cold condensate injection with the well head pressure at vacuum conditions.

Results show that the condensate injection successfully cleaned out some of the scale and improved productivity of DRJ-AA. Subsequent ring gauge surveys resulted to similar-sized tools (used before the well clean-out) reaching deeper indicating a decrease in the wellbore scale. DRJ-AA's original production of 7 - 11 kg/s increased to 16 - 19 kg/s. Geochemistry showed that the produced fluids from DRJ-AA increased in boron and decreased in NCG suggesting boiling of the condensate that was injected during the well clean-out.

1. INTRODUCTION

Darajat is the largest producing vapor-dominated geothermal field in Indonesia. It is located near Garut City, West Java Province, Indonesia, about 150 km southeast of Jakarta (Figure 1). Darajat currently has three power plants (i.e., Units I, II and III) that generate a total of 271 MW of electricity. Unit I generate 55 MW and is operated by PT Indonesia Power. Units II and III generate 95 MW and 121 MW respectively and are operated by Chevron Geothermal Indonesia.

Figure 1: Location of the Darajat Geothermal Field in relation to other cities in Java Island.

DRJ-AA was drilled and completed in September 1994; it has single section of perforated 9-⅝” production liner. The well head is connected to a 13-⅜” intermediate casing through a 13-⅝” casing head. It was drilled from the same surface location as DRJ-C, DRJ-G and DRJ-CA in Pad-3 to supply steam to power plant Unit I (Figure 2). Initial flow testing showed that DRJ-AA produces about 23.3 kg/s of steam at 16 barg Flowing Well head Pressure (FWHP).

DRJ-AA was put on production for several years without any noticeable problem until a dummy run with a 2.5” sinker bar conducted in May 2002 identified an obstruction at about 1,082 m. In 2006, another sinker bar survey was conducted and found obstruction shallower at 740 m. Furthermore in June 2008, a mechanical caliper survey was conducted and the tool stopped at 739 m (Choiri, 2008). Production testing during 2008 indicated that the well could produce 12.2 kg/s at 16.8 bara FWHP, indicating a production decline of ~12.1% per year. The identification of the obstructions and accompanying high decline rate in DRJ-AA led to the first well intervention work conducted in 2008.

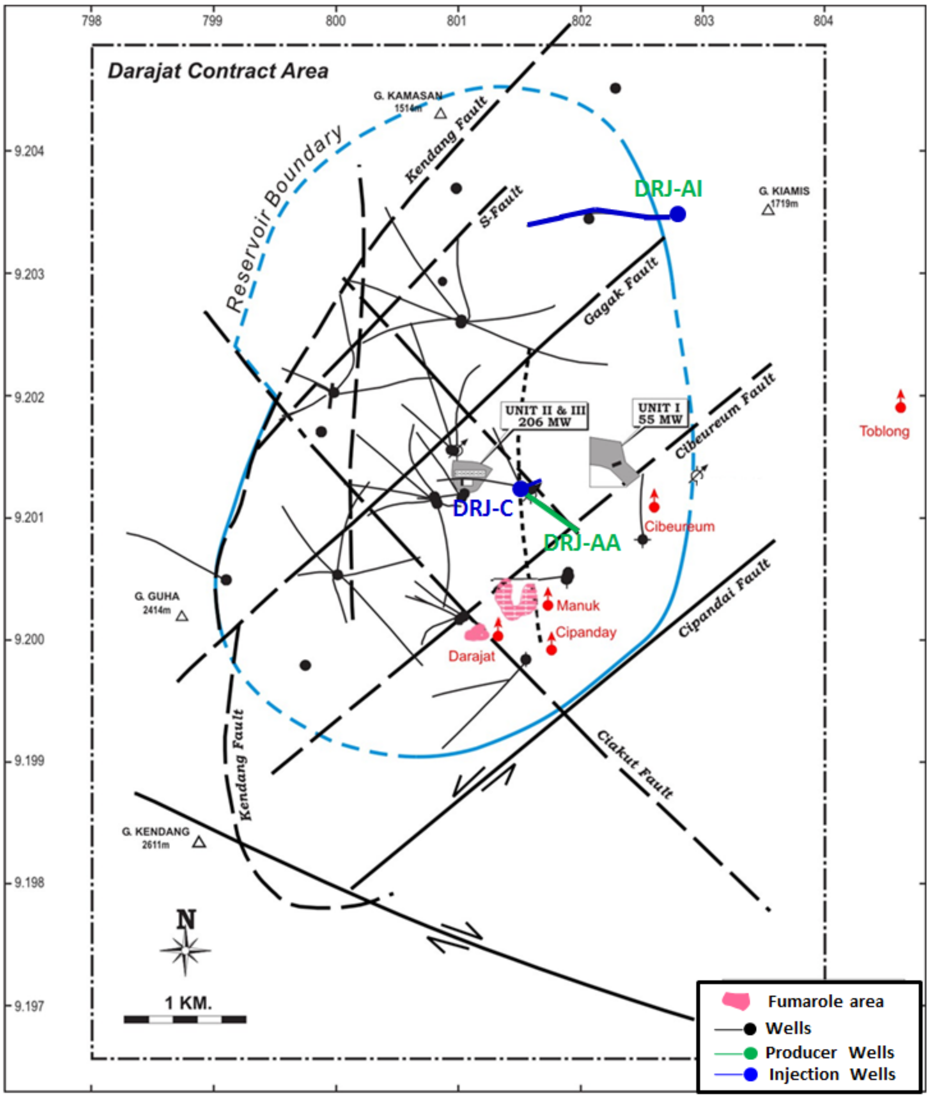

Figure 2: Map of the Darajat Field showing the location of DRJ-C, the dedicated injector for Unit I condensate, and DRJ-AA, the well with obstruction.

The 2008 well intervention work in DRJ-AA using a small rig aimed to clean the obstruction in the wellbore and improve the deliverability of the well. The well work over include running a 12-¼” bit in the 13-⅜” casing section and an 8-½” bit in the 9-⅝ perforated liner down to 1,434 m. Unfortunately, this work over was unable to deliver the expected production improvement. In fact, DRJ-AA did not show any production increase (Pasaribu, 2009).

Meanwhile at Salak Field, condensate injection into the steam cap production well AWI A-E was successful (Putra, 2012). AWI A-E stopped producing completely due to ammonium carbonate (NH_4CO_3) scale build up near its wellhead, thus preventing steam flow. To remove the scale, condensate was injected into a heat exchanger, where it underwent heating with steam from an adjacent well, and then injected into the wellbore using a pump. This test proved the concept of hot condensate injection and was successful in dissolving the ammonium carbonate scale and making AWI A-E productive again.

DRJ-AA is a different case in terms of the composition of the scale (mainly silica) and its location in the wellbore (deeper, near the top of the liner and the top of the reservoir), the type of stimulation required to improve its productivity, and the reaction expected to happen in the wellbore once condensate is injected (primarily dissolution instead of decomposition as in the ammonium carbonate case). Work done in Uenotai Geothermal Field, Japan successfully reduced the amount of silica scale accumulating in the turbine by injecting water (Takayama et al., 2000). This test became the reference to plan the hot condensate injection at DRJ-AA.

It was decided to inject hot condensate instead of the common practice of injecting cold condensate (77 deg F) from the power plant, because it was already observed repeatedly that continuous high rate injection of cold condensate in the area around Pad 3 had negative impact on the steam production of the surrounding producers. The reduction of steam production was either due to increased occurrence of scaling and/or cooling as observed by an increase in NCG production. Since the solubility of amorphous and crystalline silica in water increases with increasing temperature, injecting hot condensate reduces the injection flow rate required, thereby reducing the negative production impact to the surrounding wells.

A number of attempts were performed to obtain scale samples from DRJ-AA, and in 2013 a small amount of sample was obtained in the tool. A white fragment with scratch markings in the ring gauge was observed. Initially, it was generally believed that this obstruction was silica scale. Lab analysis showed that the components present in the sample were amorphous silica, quartz, corrosion product and gypsum. However, the majority of the scale components are still forms of silica, either amorphous or crystalline.

The above references plus the successful long-term injection experiment done at The Geysers (Khan, 2008) prompted the decision to test the application of similar methodology in Darajat. In addition, reliability issues on field condensate injector DRJ-C presented an opportunity to test the idea of condensate injection to clean-out the scale at the adjacent well, DRJ-AA. DRJ-C was the only injector dedicated to dispose of the Unit I condensate (Figure 2). However, the integrity of DRJ-C has become a concern due to an observed leak at the casing head in this injector on November 2011 (Winarno et al. 2012). As a short-term preventive measure, a casing collar was installed to surround the leak in the casing head section of DRJ-C. While repairs were being performed on DRJ-C, the injection needed to be reduced. Excess condensate was then planned to be injected into DRJ-AA.

This injection clean-out experiment at DRJ-AA was planned to be done in two stages. The first stage was utilizing a PD pump to maintain a well head pressure of 3-5 barg. The objective of this stage was to test the capability of the positive displacement (PD) pump in maintaining positive WHP in the target pressure range to affect the heating of the condensate being injected. A Pressure-Temperature-Spinner (PTS) survey was then planned to follow to determine how much production improvement occurred in the first stage. The second stage is the normal long-term injection stimulation with cold condensate.

2. THEORY AND IMPLEMENTATION

2.1. Well Selection Process

Aligned with Chevron's Well Reliability and Optimization (WRO) Base Business process, several candidate wells (including DRJ-AA) were identified for well work/stimulation with a coiled tubing unit (CTU). As DRJ-AA is located on the same pad as DRJ-C, it was decided to use DRJ-AA for this condensate injection clean-out/stimulation exercise prior to any CTU well work/stimulation. In addition, DRJ-AA was selected due to the following reasons:

- Logging depth appeared to be shallower than previous surveys, indicating build-up of scale in the wellbore;
- Anomalous pressure decline of about 1.4 bar/year was observed (neighboring wells exhibit a pressure decline of about **0.6 to 1** bar/year);
- High production decline accompanied by high downhole superheat.

2.2. Injection Test Design

In high enthalpy geothermal reservoirs, silica can be a major problem (Tassew, 2001). Lab analysis of the wellbore obstruction samples collected in DRJ-AA indicated that silica was one of the main components of the sample. Samples from other wells in the immediate area also showed that the scale composition mainly as silica.

In the initial plan, the hot condensate injection was originally for 24 hours duration. Either NaOH or KOH would be added into the condensate to increase the pH of the solution to further increase silica solubility. In addition, the condensate + NaOH solution was planned to be heated using steam from an adjacent well through a production line modification so that the injected fluid would be hot and have a high pH.

However, risk analysis with the consideration of the complexity of the operation prompted the team to simplify the clean-out/stimulation project into two stages, namely, (1) condensate injection using a PD pump followed by (2) long-term injection by gravity. The goal of the first stage of hot condensate injection stage was the dissolution of silica scale in the well bore and near well bore area, after which a PTS survey was planned to gauge the effectiveness of the hot condensate injection. Ring Gauge surveys were also planned to determine whether scale in the production casing was removed.

Figure 3 shows the injection system set-up during the condensate injection at DRJ-AA.

The long-term injection of condensate is to stimulate the well by creating interconnected fractures in the reservoir similar with what was done at The Geysers (Khan, 2008), where geothermal wells were injected with cold liquid for a certain time period and allowed to heat-up for a similar time duration. After the particular well was put back on production, a significant production improvement was observed. Grant et.al (2013) explained that injecting cold fluids could thermally induce rock contraction and causes permeability increases. This could allow interconnected fractures to eventually connect with the permeable fractures in the reservoir. This kind of injection into vapor-dominated geothermal system is also recognized as a powerful technique to increasing sustainability of the reservoir by maintaining reservoir pressures and production flow rates. Kneafsey et al. (2008) proved that cold fluid injection can also increase the steam quality by decreasing the concentration of non-condensable gas (NCG) in the produced steam.

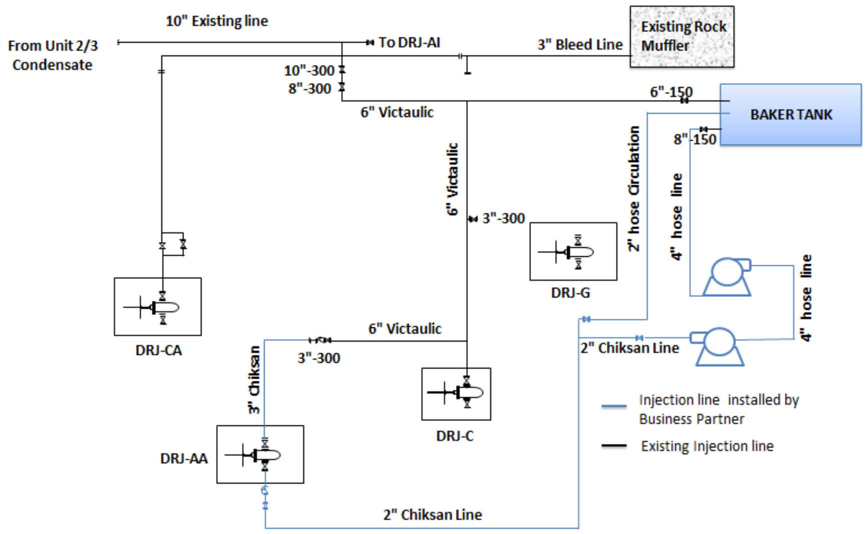

Figure 3: Injection system schematic during the DRJ-AA clean-out/stimulation experiment through condensate injection.

During the planning phase, it was recognized that there were at least two weaknesses of this experiment, namely, the 24-hour duration to conduct the hot condensate injection was a big uncertainty and probably will be limited by the PD pump reliability. Additionally there was insufficient time to run the PTS and Ring Gauge surveys and adequately assess the effectiveness of the first stage because the problem with DRJ-C was found to be much more critical and the well had to be plugged and abandoned. All the condensate from the power plant had to be transferred to DRJ-AA much earlier than planned. With these uncertainties, the main objectives of the clean-out/stimulation project were revised as:

- Determine whether the output of the PD pump can be controlled while maintaining positive WHP to affect heating of the condensate above the reservoir ;
- Assess whether the obstruction can be removed and the well's productivity be improved;
- Test the concept of producing Injection Derived Steam (IDS).

3. FIELD EXECUTION

The first phase of the DRJ-AA condensate injection (or the hot condensate stage) started at Feb 22, 2012 as shown Figure 4. The PD pump was used continuously for about eight hours. The cold condensate injection stage commenced right after completion of the hot condensate injection and lasted until April 23, 2012 (Figure 4).

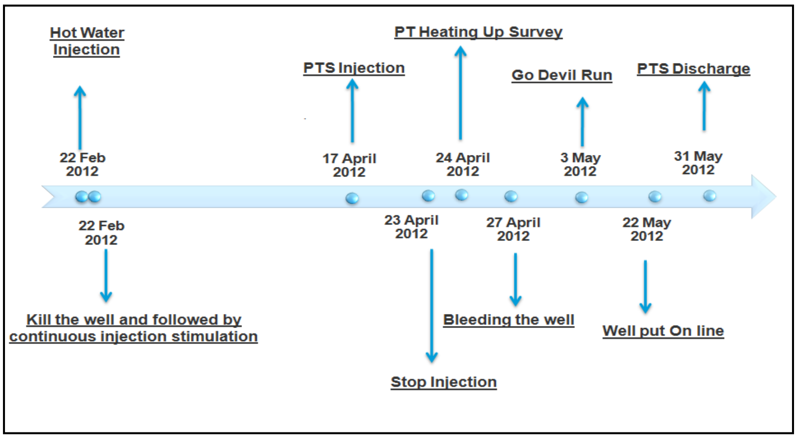

Figure 4: Time sequence of the DRJ-AA Clean-out/Stimulation through condensate injection.

Figure 5 shows the results of WHP monitoring during the first stage of hot condensate injection into DRJ-AA. During the first stage of the injection test, the WHP was initially 25 barg and slowly decreased to about 5 barg. The WHP was then maintained positive by controlling the PD pump output at about 2-3 BPM injection rate for about 8 hours. After this first stage of hot condensate injection, the well was injected with condensate by gravity for about two months (under vacuum condition) with injection rate around 12 BPM until April 23, 2012. A sequence of tests, namely injection, PTS, heat-up and Ring Gauge surveys, were conducted after the condensate injection. DRJ-AA was put back on production on May 22, 2012 and a discharge PTS survey was conducted on May 31, 2012 to conclude the Clean-out/Stimulation project.

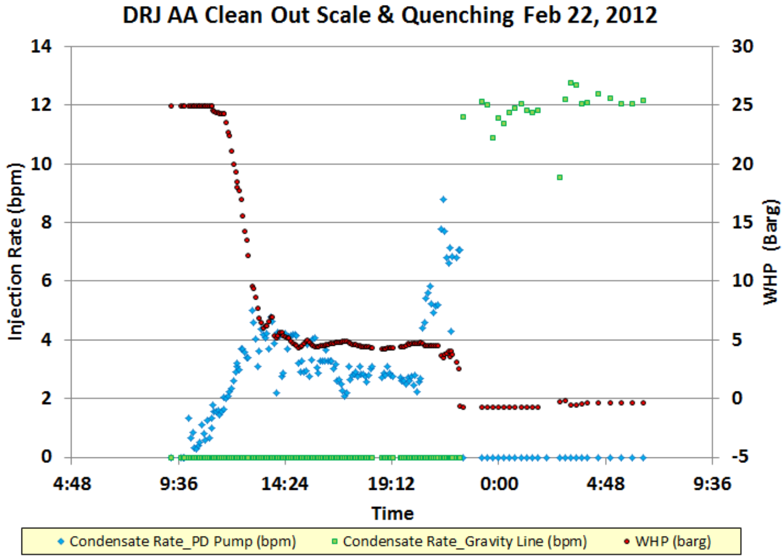

Figure 5: Chart showing the evolution of the WHP during the DRJ-AA Clean-out/Stimulation Project.

4. EVALUATION OF INJECTION TEST DATA

4.1. Interpretation of Ring Gauge Runs

As mentioned previously, DRJ-AA has single section of perforated liner 9-⅝" and the wellhead is connected to the 13-⅜" intermediate casing with a 13-⅝" casing head. This well has a 34º inclination with the Kick-Off Point (KOP) at about 372 m. At Chevron, ring gauge runs are normally conducted in the production casing until before the top of liner (TOL); at DRJ-AA case, the TOL is at 1,012 m.

The ring gauge runs indicated that there was an increase of about 200 m in the Maximum Clear Depth (MCD) in the production casing for the 8.5" ring gauge. Before the condensate injection, the 8.5" Ø ring gauge tool could only go down to 620 m while the 3.5" Ø ring gauge could go down to 834 m only (Figure 6). After the combination of hot and cold condensate injection, the 8.5" Ø ring gauge could reach until 780 m (i.e., deeper by 160 m from the before condensate injection run) while the 3.5" Ø ring gauge reached as deep as 1,020 m (again, deeper by 180 m from initial).

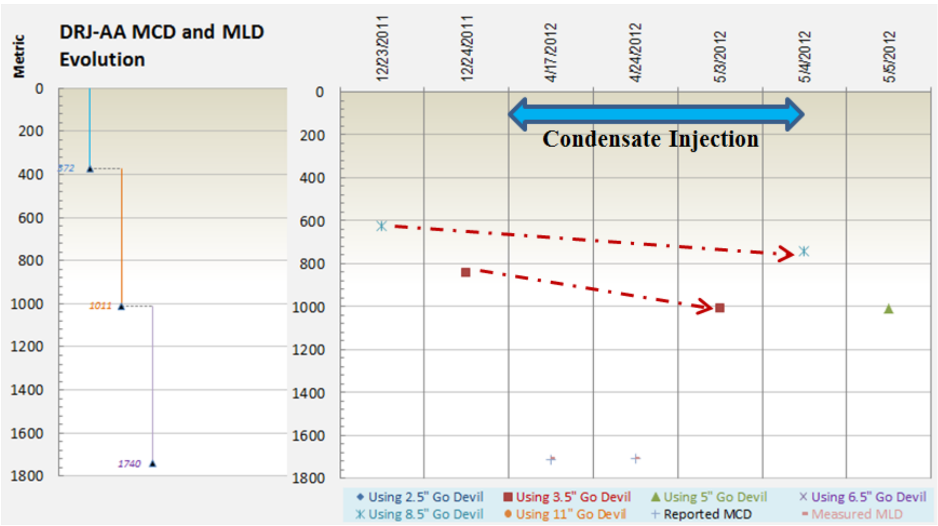

Figure 6: Evolution of the Maximum Clear Depth (MCD) of DRJ-AA showing the deeper penetration of tools after the conclusion of the condensate injection test.

4.2. Injection Pressure-Temperature-Spinner (PTS) Analysis

The Injection PTS survey on April 17, 2012 indicated that DRJ-AA has two shallow feed zones that are producing steam and two other feed zones that are accepting liquid (Adityawan, 2013) (Figure 7). Table 1 shows the estimated specific contribution of the four feed zones. Note that the two shallow feed zones at 1,141 m and 1,208 m MD were producing steam even while about 45 kg/s of condensate was being injected into the well. The injected condensate was exiting the wellbore in the two deeper feed zones at 1,441 m and 1,552 m MD (Figure 7 and Table 1).

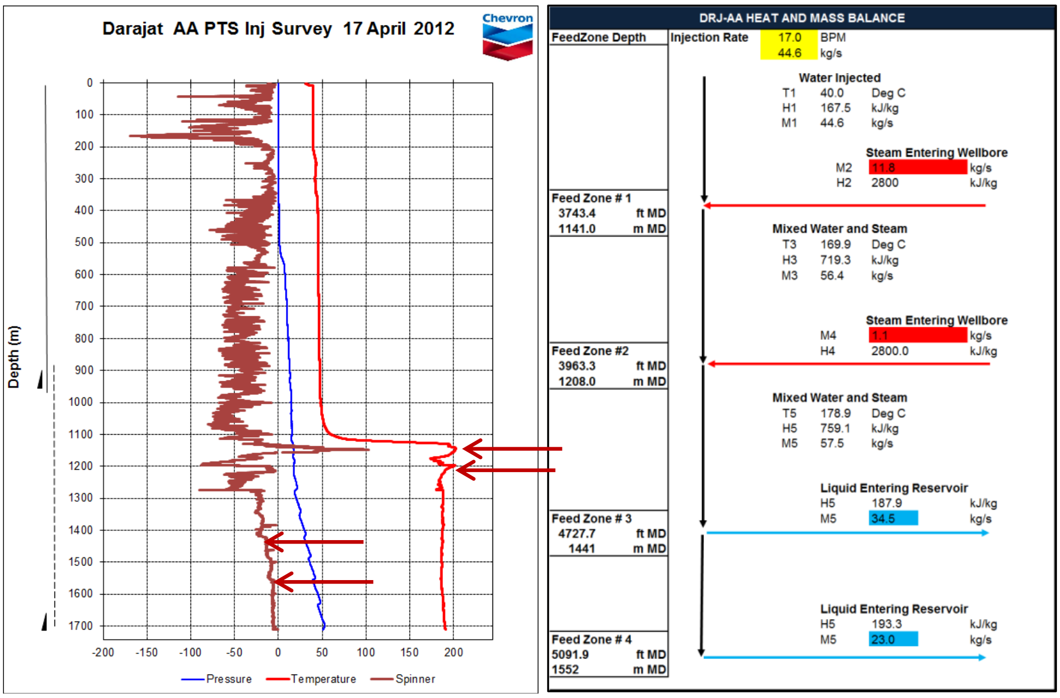

Figure 7: Injection PTS at DRJ-AA showing the depth where fluids exit the wellbore (arrows in left chart).

Table 1: Feed Zones and PI comparison based on Injection PTS

Number	Depth (m)	Fluid Flow	Fraction	Mass, kg/s	II, kg/s-bar	PI, kg/s-bar	Remarks
1	1,141	In				0.56	
2	1,208	In				0.23	
3	1,411	Out	0.6	26.8	5.69	0.73	Injected 44.6 kg/s of condensate.
4	1,552	Out	0.4	17.8	1.65	0.21	

4.3. Discharge PTS Analysis

A Discharge PTS survey was conducted on May 31, 2012 or about five weeks after the termination of condensate injection and the well was put on bleed. This survey was conducted with the objective of better understanding the initial well deliverability after DRJ-AA has heated up. During this PTS survey, it was observed that the liquid inside the wellbore had not yet completely disappeared, indicating that either DRJ-AA has inherent low permeability or that the fractures encountered by the well were blocked with debris, thus preventing/slowing down migration of the liquid inside the wellbore into the reservoir.

Analysis of the May 2012 Discharge PTS data showed that there was improvement in both the shallowest and bottom feed zones (Table 2). The shallowest feed zone PI increased by almost four times compared with the 2008 Discharge PTS result (i.e., 1.18 to 4.81 kg/s-bar in Table 2); similarly, the bottom feed zone PI increased by almost seven times. Production-wise, the bottom feed zone was estimated to produce almost 40% of the total deliverability of DRJ-AA compared with the estimated 13% during the 2008 Discharge PTS survey. It is generally believed that these improvements were due to the combination of both scale dissolution (during the hot condensate injection) and mechanical scale reduction by the erosional velocity of the injected fluid during the two-months condensate injection by gravity.

Table 2: Historical Feed Zone and PI comparison

		2006 Discharge **PTS**		**2012 Injection PTS**	**2012 Discharge PTS**	
MD (ft)	**MD (m)**	**PI (kg/s-bar)**	**% Fraction**	**PI (kg/s-bar)**	**PI (kg/s-bar)**	**% Fraction**
3,743	1,141	1.18	0.87	0.56	4.81	0.61
3,963	1,208	N/A		0.23		
4,629	1,411	0.22	0.13	0.73	1.68	0.39
5,092	1,552	N/A		0.21		

As shown in Table 2, new feed-zones were identified during the PTS injection survey. This is normal because during injection the upper portion of the production zone (above the liquid level in the wellbore), the pressure is much lower than during production or during a production PTS. This results in a bigger pressure difference between reservoir and wellbore in the upper permeable zone where the steam is entering wellbore. On the other hand, at the bottom of the wellbore where there is a liquid column the difference between the wellbore pressure and the reservoir pressure is much higher than during production. Furthermore, the injected condensate cools the reservoir rock making it contract to increase the fracture size and the fracture permeability. During normal production conditions, some of the permeable zones identified by an injection survey may or may not be contributing steam to the wellhead.

The PTS results and the Productivity Indices (PI) were processed with Geoflow (Chevron's wellbore simulator) to estimate DRJ-AA's deliverability after the condensate injection. Figure 8A shows that the steam deliverability of DRJ-AA post-condensate injection was estimated at about 16 – 19 kg/s at a FWHP of 16 Bara. This deliverability is more than 50% from its initial production of 7 - 11 kg/s.

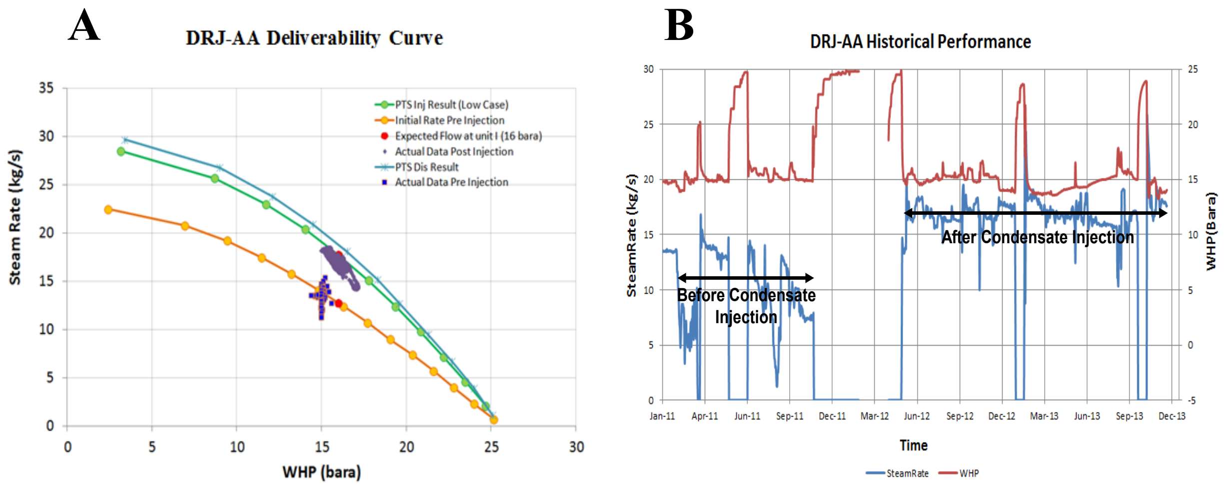

Figure 8: Comparison of actual and estimated deliverability curves of DRJ-AA.

The increase in the initial well deliverability indicated by the wellbore model result during the PTS survey agrees with the actual historical production. As shown in the figure 8B above, this increase was sustained for a year and a half after the experiment, indicating that this increase is not just a short time peak, but able to maintain the production rate in the range of 16 – 19 kg/s for quite a long time .

5. THEORIES EXPLAINING THE PRODUCTION INCREASE

Based on the phenomenon that was observed in DRJ-AA production behavior, there are at least three possible explanations to the increase in steam deliverability.

5.1. Wellbore clean out from scaling due to first stage and second stage of injection

Based on the ring gauge results, there was indication of scale reduction after the injection test as shown by the deepening of MCD. Using the model from Ocampo-Diaz et al. (2005), the shape of the initial scale accumulation (before clean-out) in the wellbore most likely looked similar to Figure 9 below. Before the injection test, the 8.5' Ø and 3.5" Ø ring gauges encountered obstructions at about 620 m and 834m, respectively. After the injection test, the ring gauges could reach deeper until 780 m (for the 8.5" Ø) and the Top of Liner (1,020 m) (for the 3.5" Ø). From the results of the ring gauge runs, it can be concluded that some of the scale in the upper part has been dissolved with the combination of both injection stages, thus allowing the ring gauges to log deeper.

A PTS survey was done in October 2013 while DRJ-AA was on bleed (bleed rate is about 0.1 – 0.3 kg/s of steam) through the 3" wing valve. The survey was done primarily to determine if there is cross-flow in the wellbore induced by the well crossing a suspected fault/structure that compartmentalizes the Darajat reservoir. The data obtained can also be used to help identify where the remaining scale is located in the wellbore.

- The PTS response tagged as #1 (1,410 m) and #2 (1,140 m) show the major feed zones (FZ) of this well (Figure 10) and agrees with the interpretation of the previous survey. FZ #1 shows a significant inflow in to the wellbore which flows back into the reservoir at FZ #2 since the spinner goes to zero at this point. This confirms the cross-flow in the wellbore indicating that the fault is somewhere between the two FZs. However, there is still an upward flow of steam from this point since the well is under bleed condition. However, the spinner could not detect it because the flow velocity is below the spinner threshold.
- At about 1,020 m – 1,050 m, just below the production casing shoe, there was an increase in spinner velocity (marked as #3 in Figure 14) even though there are no identified feed zones at this depth. Also, this is an area where there were no casing diameter changes. A possible explanation of this apparent increase in flow velocity is a constriction or reduction in wellbore size most likely due to scaling. Therefore, we can speculate that the major scaling in the well occurs at this point and continues up the wellbore.
- At about 700 – 800 m and 950 – 1,000 m (tagged as #s 5 and 4, respectively, in Figure 10) inside the production casing, the spinner rotated in the opposite direction. This behavior is an indication of down flowing fluid movement in the wellbore and could be explained by the condition of the well during the PTS survey. While on bleed condition, there is steam flowing from the reservoir to the wellhead. A well is put on bleed so that it remains hot. As the steam flows to the surface some of it condenses to water because of heat loss in the well bore to the surrounding rock. It flows back down to the reservoir. The

spinner does not detect this water above the KOP since there the well is still vertical and the spinner tool is at the center of the wellbore. Below the KOP, the wellbore is now at an angle and the liquid flows on the low side of the wellbore where the tool will also rest. Normally, there is a steady increase in liquid down flow as liquid accumulates. However, in the area whereit is believed that scale exists, the area available to flow is reduced, increasing the velocity.

This spinner response further validates the conclusion of the ring gauge runs that there is a partial decrease of scale in the wellbore but it was not totally dissolved.

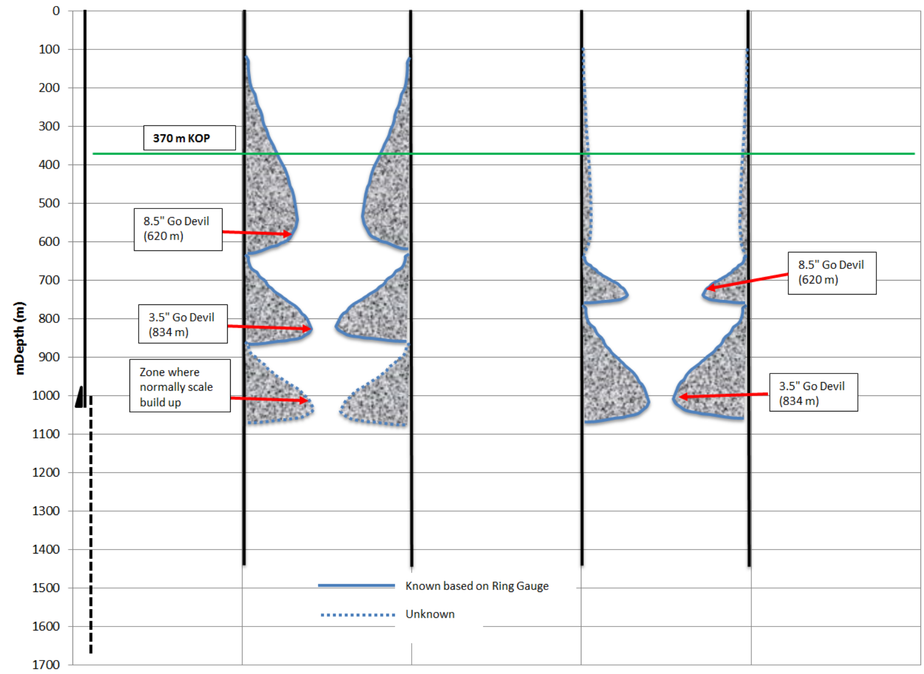

Figure 9: Cartoon showing the apparent change in the wellbore scale before and after injection.

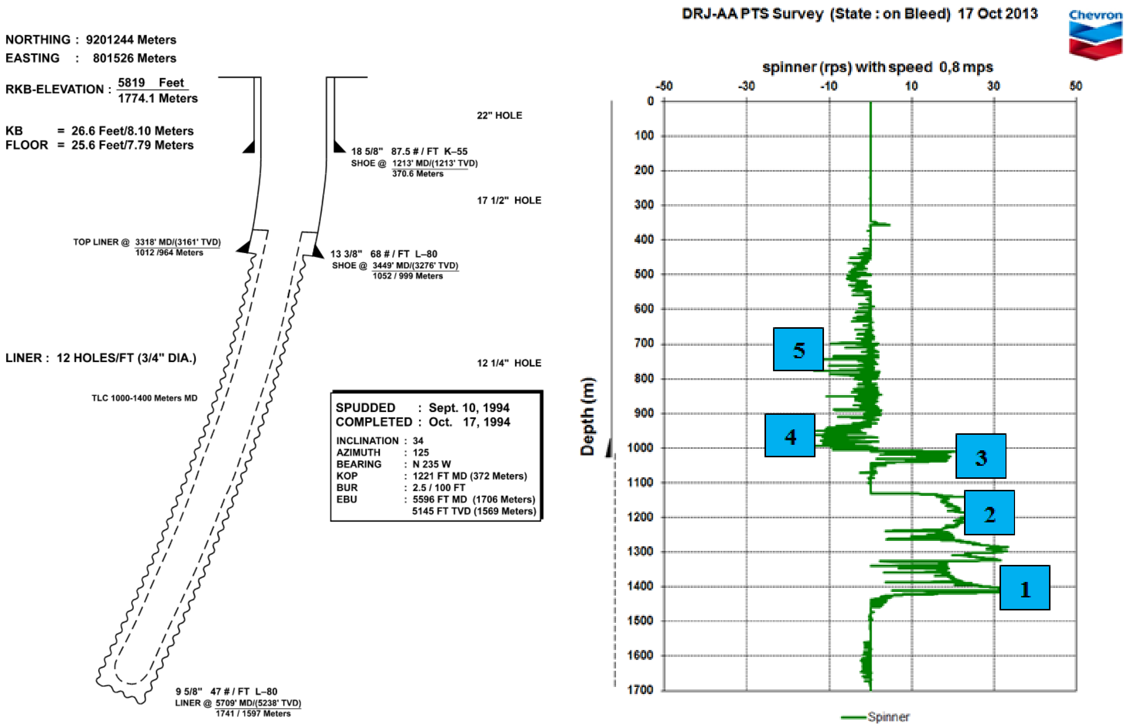

Figure 10: Chart showing DRJ-AA well geometry and spinner behavior during the PTS survey on bleed condition. Depths tagged as #s 3, 4 and 5 are the locations where scale is believed to exist.

5.2. Injection Derived Steam (IDS) from the injected condensate

IDS calculation has been being used at Darajat geothermal field to monitor the proportion of steam that is being generated from boiled injection liquid. This is normally done by comparing the initial produced NCG with the current produced NCG. Since boiling controls the IDS, thus NCG and IDS should have the opposite relationship. In the other words, the higher the NCG, the lower IDS produced and vice versa.

Historically, DRJ-AA had been producing NCG at ~1.3 wt% with boron in steam condensate at ~4 ppm. Condensate injection at DRJ-AA in 1Q and 2Q 2012 at ~35 l/s provided additional steam from the boiled condensate as indicated by the increase in boron and decrease in NCG or higher in IDS after the injection (Figure 15). This hypothesis is supported by DRJ-AA's decreasing steam rate beginning 2Q 2013 even if there was no change in WHP. This is an indication that the IDS effects start to deplete and it is followed by downhole superheat increase based on PT measurement data in October 2013 (Figure 12B).

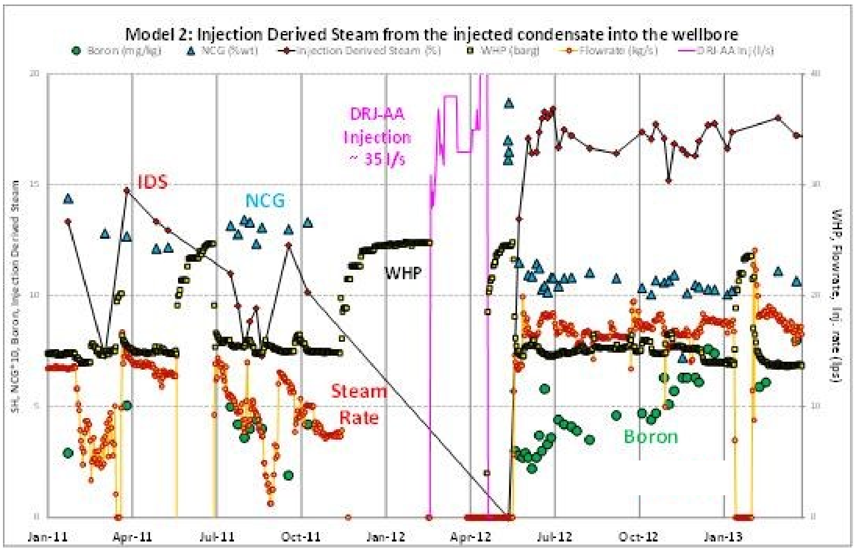

Figure 11: Estimated IDS in DRJ-AA (represented by red circles). As boiling controls the IDS, NCG and IDS should have opposite relationship. Higher IDS results to lower NCG and vice versa. The 2 months injection provides temporary additional steam as indicated by steam rate which also corresponded by IDS, NCG and Boron that indicate the injected liquid was boiled.

<u>5.2.1 Pressure-Temperature (PT) and Superheat Monitoring</u>

By comparing the pressure trends of 2008, 2011, and 2012, it can be seen that the expected pressure decline is occurring as the reservoir is exploited. However, comparison of pressure measurements in 2011 and 2012 with 2013 indicate that, instead of decline the pressure actually increased (Figure 13A). The 2012 survey was conducted on April 24th, or about a day after the condensate injection was stopped and was lower by 1.7 Bara compared with the 2011 survey. In normal operating condition, it is expected that the 2013 pressure profile should have been lower by at least 1 bara. This anomaly is due to Unit 1 and Unit 2 power plants shutdown (decreasing mass extraction by about 55%) whereas unit 1 shutdown for two weeks and unit 2 shut down for about six months respectively. Note that the liquid level in 2012 (right after the condensate injection) was at about 1,520 m similar with the liquid level in 2008 right after well completion (Figure 13A) and this liquid level disappeared in the following survey.

Figure 13B shows the superheat profiles of DRJ-AA pre- and post-condensate injection. In the historical temperature measurement of DRJ-AA, it is shown that the well is almost always in saturated condition and show superheat in the bottom, except the temperature reading in 2012 that shows some under saturated temperature due to the well heating up after the injection test.

In May 2011, or about a year before the 2012 condensate injection at DRJ-AA, bottom hole superheat was estimated at 5ºC (Figure 8B). As expected, the bottom hole portion of DRJ-AA significantly cooled during the condensate injection; hence, the April 2012 superheat estimate was negative. In October 2013, the well has almost rebounded back to its pre-condensate injection conditions as the estimated superheat was about 3ºC (Figure 8B). This estimation is due to higher pressure reading as an effect of power-plant shut-down, under the normal condition the pressure must be lowered with lower Pressure, the actual superheat in October 2013 must be around 5^{o}C or even higher. This is an indication of the IDS effect is in depletion already as elaborated in the previous section.

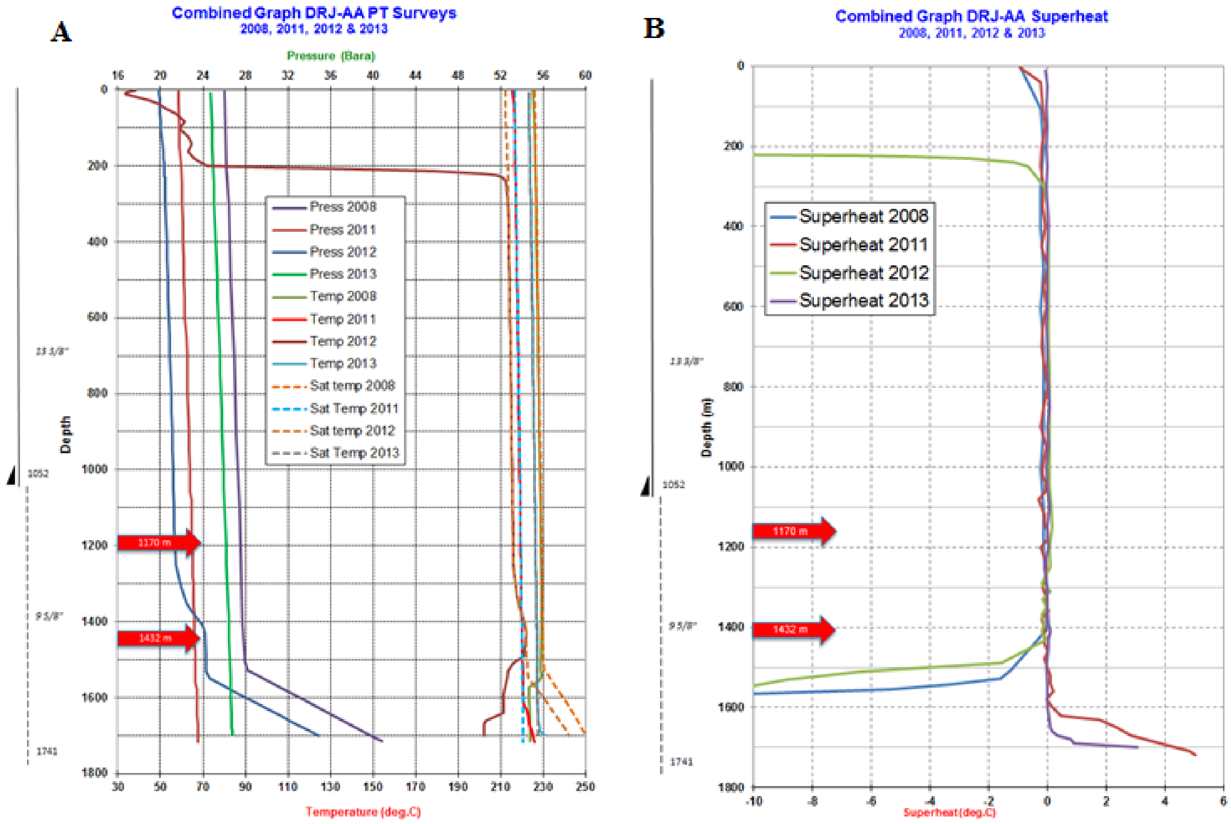

Figure 12: Charts showing historical (A) pressure and temperature and (B) superheat profiles of DRJ-AA.

6. CONCLUSIONS

The hot and cold condensate injection at DRJ-AA successfully improved the well's deliverability and appeared to remove some of the scale inside the production casing shoe. The scale was believed to have been partially removed by a combination of both dissolution and erosion by the injected condensate. Since the PTS and ring gauge surveys between the hot and cold injection stages were not performed, we cannot tell for sure if the short term hot condensate injection process was more effective than the usual cold condensate injection. The remaining scale can serve as nucleation points for new scale to build up. Therefore this process of scale removal by injection is not as good as a more thorough mechanical cleaning using a liquid jetting tool such as BJ's Rotojet or Schlumberger's Jet-blaster.

Some of the increase in productivity can be attributed to increased IDS production. It remains to be seen if this is true by continuous monitoring of the produced steam chemistry.

This injection test was operationally successful to meet the planned objectives to test feasibility of maintaining positive WHP while injecting certain amount of condensate and to test whether a long term injection could contribute to production improvement.

7. ACKNOWLEDGEMENT

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