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Sand Problem Handling Strategy on Well AR-02 with Hydraulic Pumping Unit

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ABSTRACT

AR-02 well is one of the oil production wells located in Structure X. This well is produced using the Hydraulic Pumping Unit (HPU) method due to low reservoir pressure as a result of the reduced production capacity of the Y Field formation. In addition, this well has sand problems because the fluid production rate of 96 bfpd exceeds the critical sand flow rate of 66.81 bfpd. The physical properties of reservoir rocks do not cause sand problems because they have a cementation factor of highly cemented (m = 1.99), relatively small clay content (5.4%), compact rock (Δt = 54.16 s/ft), and compact as well as stable formation rock (G/Cb = 14.85x1012 psi2). In solving the sand problem in the AR-02 Well, the Gravel Pack and screen were installed. The correct Gravel size according to the Saucier method is 0.035 inch and the correct screen size according to the Coberly & Wagner, Tauch & Corley, and H. J. Ayre methods is 0.016 inch. The value (G-S) ratio indicates that the selection of Gravel and screen sizes is correct (stable), namely the value (G-S) ratio is at number 5. Redesign of the production scheme due to the installation of the Gravel Pack with the use of HPU pumps at the same setting produces; P due to Gravel installation 40 psi, qfluid after Gravel installation 90 bfpd (previously 95 bfpd), PI after Gravel installation 0.188 (previously 0.198), Min allowable stress 8991.56 psi, Max allowable stress 23420.64 psi, Total stretch 55.42 inch, Over travel 0.391 inch, Plunger stroke 94.97 inch, and Pump Displacement 135.65 bfpd.

Keywords: : sand problem; gravel pack; hydraulic pumping unit; sand; screen

I. INTRODUCTION

The AR-02 well is one of the oil production wells located in Structure X. The reservoir for Structure X is located in the Baturaja Formation (BRF) which is carbonate rock at a peak depth of -2,200 mbpl. The initial reservoir pressure is 3,305 psi, the reservoir temperature is 295 °F and the bubble pressure is 2,525 psi, the reservoir is undersaturated. This formation is divided into 2 zones, namely Upper BRF and Lower BRF. Upper BRF consists of Sub zone 1 Upper BRF and Sub zone 2 Upper BRF. Upper BRF has relatively good porosity and permeability in the range (6-20) % and permeability (0.2-20) ms. Structure X was discovered in November 1997, with an initial production rate of 1.085 BOPD, 0.79 MMSCFD and very low moisture content. The total production rate of AR-02 well is 96 BFPD with a water cut of 25% and a gas liquid ratio (GLR) of 2782.66 SCF/BBL. Structure X is located in the capital city of South Sumatra, including within the working area of PT Pertamina Hulu Rokan, Field Y. This well is produced using an artificial lifting method of HPU pump (Hydraulic Pumping Unit) due to low reservoir pressure as a result of the reduced production capacity of the formation belong to Field Y. In addition, this well is experiencing sand problems so it needs an evaluation of strategy to find a solution without decreasing the well effectivity.

The sand problem occurs due to the bond stability damage of the sand grains caused by friction and collisions by a flow of fluid where the flow rate that occurs exceeds the maximum limit of the allowed critical flow rate, so that the sand grains are produced together with oil to the surface. Co-production of sand with production fluids is a common problem in oil fields, which is usually associated with transient shallow formations, and in some areas sand problems are encountered at depths of 12,000 ft or more. This is because the wells produce from unconsolidated layers (easily released), so that it can interfere with the productivity of the wells and can damage production equipment. This problem is caused by the presence of sand-sized grains around the well carried by the fluid flow and will be buried at the bottom of the well (for large grains) or carried to the surface (for small grains).

There are generally three classifications of formation sands:

1. Quicksand (completely uncoupled formation sand)
2. Partially Consolidated Sand (has cementation but only weak linkage)
3. Friable Sand (semi-competent, cemented and potentially disruptive)

The factors that influence the tendency of a well to produce sand are:

1. Degree of cementation of rock

2. Formation strength
3. Critical flow rate
4. Formation clay content
5. Reservoir pressure drop.

In general, the actual sand problem can be identified with the following parameter criteria:

1. The rock cementation factor is relatively small (less than 1.8).
2. Relatively small formation strength (less than 0.8 × 1012 psi2).
3. High production rate (greater than the critical production rate) causes high fluid drag force. This causes the sand stability curve to collapse.
4. The increase in water saturation will cause the clay in the formation to expand. This causes the curvature of stability to be reduced, therefore the curvature of the sand stability is easy to collapse.

Sand problems occurred several times in the AR-02 well with a probability due to the low compaction of the reservoir rock of the well or the rate production exceeds the maximum critical rate. The production of formation sand along with oil-water-gas can affect the performance of the installed HPU pump. Where the pump can get stuck which will cause a decrease in oil production. This problem resulted in the AR-02 well-being frequently shut-in and a decrease in production efficiency. Therefore, in this study, a discussion and evaluation of planning will be carried out in dealing with sand problems in the AR-02 well.

II. METHODS

The method applied for handling strategy of sand problem in the AR-02 well consists of three stages. The first stage begins with evaluating and analyzing the parameters that can be the cause of sand that occurs in the AR-02 well. After knowing the cause of the sand problem that occurred in the AR-02 well, the second stage was to tackle the sand problem. Sand management is carried out by installing a Gravel Pack and a screen which determined based on calculations and analysis. The last stage is to redesign the production scheme on the AR-02 well while still using existing production equipment in the field, namely using the artificial lift production method using the Hydraulic Pumping Unit (HPU). The description of the procedure for each stage is as follows:

1. The first stage: Evaluation of the parameters causing the sand problem

   At this stage, it begins by evaluating the physical properties of the reservoir rock against the sand problem. The physical properties of rocks evaluated include cementation of reservoir rock as seen from the cementation factor, formation stability as seen from the reservoir clay content, rock compactness from the interval transit time value from the productive zone sonic log data, and rock strength based on the calculation of the G/Cb value in the productive formation. After evaluating the physical properties of the reservoir rock, it is continued by evaluating the fluid flow rate against the critical sand flow rate.

2. Second stage: Plan to handling the sand problem

   Solving the problem of sand is done by calculating the size of the Gravel Pack and the right screen. The calculation of the gravel pack size is calculated using the Sauchier method while for the screen size using the Coberly & Wagner, Tauch & Corley, and H. J. Ayre methods. Furthermore, to ensure that the selected Gravel and screen sizes can be calculated using (G-S) Ratio.

3. Third stage: Re-design the production scheme for the AR-02 well while still using existing production equipment in the field

Gravel installation will provide additional pressure loss to the fluid flow. This pressure loss causes the flow rate to be lower than originally designed. Therefore, it is necessary to design a re-production scheme by taking into account the loss of pressure and the decrease in productivity index due to the installation of Gravel.

III. RESULTS AND DISCUSSION

Prior to the strategy for dealing with the sand problem, an evaluation was carried out to determine the cause of the sand. The evaluation consisted of 2 evaluation parts, namely the analysis of the physical properties of the reservoir rock against the sandy problem and the analysis of the fluid flow rate against the critical flow rate. In the evaluation of the physical properties of the reservoir rock, the rock cementation factor in the AR-02 well reservoir has a value of 1.99.

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According to Sparlin D.D in 1993 that reservoirs with cementation factors are classified as highly cemented reservoirs. So that the cementation of the reservoir rock is not the cause of the sand problem in the AR-02 well. Next, analyze the clay content in the reservoir formation. The clay content will affect the sand problem, especially in reservoirs with a water drive. Because when the well has been produced for a long time, the WOC will rise to the productive zone.

The contact between water and reservoir formations that have a high clay content will cause the rock in the reservoir to expand (swelling) which will affect the reservoir rock compaction which can have an impact on sand problems when fluids are produced. The Y field reservoir has a water drive propulsion. Based on the calculation of the GR log data, it was found that the clay content of the AR-02 well reservoir formation was at a value of 5.40%. This value is relatively small, so that the clay content of the formation is also not the cause of the sand problem in the AR-02 well. Next, analyze the compactness of the formation. Whether or not the formation is compact is seen from the value of the transit time interval resulting from recording sonic logs in productive formations. The principle is to determine the transit time interval (Δt) which is a function of formation lithology and porosity. Formations with a transit time interval < 95 s/ft are categorized as compact formation, 95 s/ft < (Δt) < 105 s/ft are doubtful of compactness, and (Δt) > 105 s/ft are classified as formation is not compact. Based on the sonic log data on the AR-02 well reservoir, the transit time interval for the productive formation is 54.15 s/ft. This means that based on the sonic log data, the compactness of the reservoir rock of the AR-02 well is not the reason for the sand problem in the well. Next analyze the strength of the productive formation. The strength of the productive formation is determined based on the calculation of the G/Cb value which can be seen in **Equation 1**.

$$\frac{G}{Cb} = 1{,}34^2 \times 10^{20} \left(\frac{AB\rho_b{}^2}{(\Delta t)^4}\right) \qquad (1)$$

From the above equation, the G/Cb value in the productive formation of the AR-02 well is 14.85 x1012 psi^2. The G/Cb value is > 0.8 x 1012 psi^2, so according to Tixier, the formation is strong/compact (stable). From all the analysis of the physical properties of the reservoir rock against the sand, it can be seen that the physical properties of the reservoir rock are not the cause of the sand problem in the AR-02 well.

Next, analyze the fluid flow rate against the critical flow rate of sand. Sand problems can occur if the fluid flow rate exceeds the critical sand flow rate. Based on the calculation, the critical flow rate for the AR-02 sand well is 66.81 bfpd. While the actual fluid flow rate is at 96 bfpd. So that the cause of the sand problem that occurs in the AR-02 well is that the fluid flow rate exceeds the critical sand flow. If it is observed from the parameters that affect the critical flow rate of sand, the thing that can be done to increase the critical flow rate is to change the formation permeability parameter and/or change the number/density of the perforation holes. Increasing the permeability of the formation can be done by acidizing considering the lithology of the reservoir rock is a carbonate reservoir. Meanwhile, changing the number/density of perforated holes can be done by re-perforating. However, the discussion of this thesis is limited to considerations of optimization and installation of special equipment on the AR-02 well as well as the existing HPU pump using equipment that already available in the field. Therefore, the consideration of doing acidizing and re-perforating will only be included in the recommendations section.

After knowing the cause of the sand, the next step is to overcome the problem of sand. This countermeasure includes the installation of Gravel Pack and screen liners. Before determining the size of the Gravel Pack and screen liner that is suitable for use, it is necessary to analyze the sieve data first.

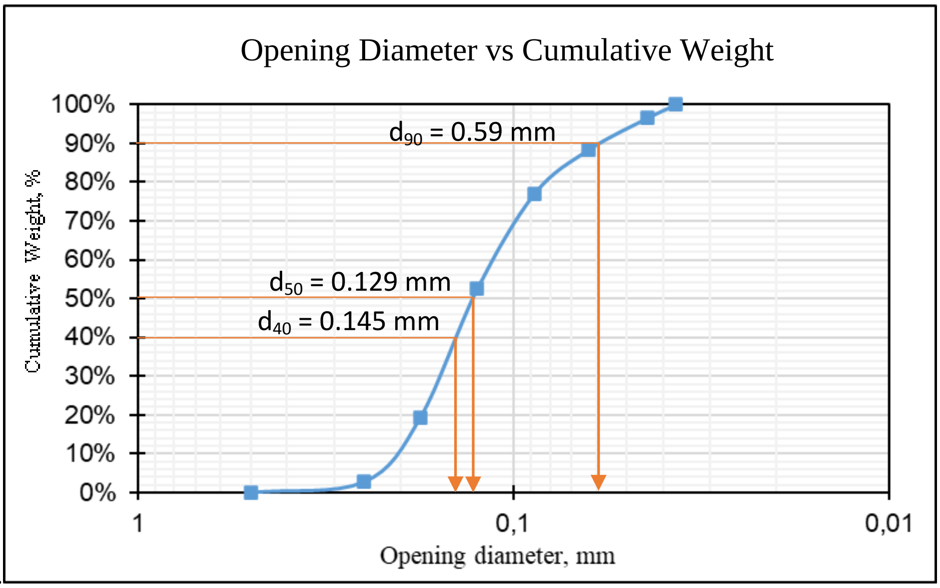

Figure 1. Results of Grain Size Analysis of the "AR-02" Well Formation

From the graph of the formation grain size analysis of AR-02 well, the values of the cumulative weight 40% (d40), cumulative weight 50% (d50), and cumulative weight 90% (d90) are tabulated in the following table.

Table 1. Values of d40, d50, and d90

d_{40}		d_{50}		d_{90}	
Mm	Inch	Mm	Inch	Mm	Inch
0.145	0.005709	0.129	0.005079	0.59	0.023228

Therefore, from these data it can be calculated the value of the uniformity coefficient of the formation grains using **Equation 2.**

$$C = \frac{d_{40}}{d_{90}} \qquad (2)$$

Sieve data is rock core analysis data to determine the sorting or distribution of reservoir rock sizes. After analyzing, it was concluded that the AR-02 well reservoir rock had a good distribution/sorting because the C value was at 2,434. Furthermore, the calculation of the selection of Gravel Pack is carried out. Gravel Pack size selection is done by the Saucier method, namely the recommended Gravel Pack size is 5 to 6 times the data d50 sieve data. With the Gravel size range, the values of $5d_{50}$ and $6d_{50}$ are 0.02537 inch - 0.003045 inch, the recommended Gravel size is 16-30 U.S. Mesh. Gravel size can be determined based on the available screen sizes in the following table.

Table 2. Available Gravel Sizes (Source : Benipal, N.S., 2004)

Size *Gravel* (Inch)	U.S. Mesh (Size)	Diameter median (Inch)
0,006 x 0,017	40/100	0,012
0,008 x 0,017	40/70	0,013
0,010 x 0,017	40/60	0,014
0,017 x 0,033	20/40	0,025
0,023 x 0,047	16/30	0,035
0,033 x 0,066	12/30	0,05
0,039 x 0,066	12/18	0,053
0,033 x 0,079	10/20	0,056
0,047 x 0,079	10/16	0,063
0,066 x 0,094	8/12	0,08
0,079 x 0,132	6/10	0,106

Table 3. Gravel Size Used

d_{50} Sand (Inch)	$5d_{50}$ (Inch)	$6d_{50}$ (Inch)	*Gravel*	
			(U.S.Mesh)	**(Inch)**
0.005079	0.0254	0.0305	16-30	0.035

So that the correct Gravel Pack size for the AR-02 well is 0.035 inch. After that, the calculation is carried out to determine the right screen size. Screen size is determined based on the method of Coberly & Wagner, Tauch & Corley, and H. J. Ayre, i.e. A good screen size to choose is one that can hold Gravel grains in place and can provide sufficient flow area. Based on the size of the Gravel, the determination of the screen size used is 0.016 inch.

Table 4. Screen Size Used Based on Gravel Range Size
(Source : Economides, 1993)

Gravel Size	*Gravel* Size (Inch)	Screen Range (Inch)	Screen Gauge
40 – 60	0.0165 – 0.0093	0.008	8
30 – 50	0.0230 – 0.0120	0.010	10
20 – 40	0.0330 – 0.0165	0.012	12
16 – 30	0.0460 – 0.0230	0.016	16
12 – 20	0.0660 – 0.0330	0.020	20
8 – 16	0.0940 – 0.0460	0.028	28

Table 5. Screen Size Used

d_{50} Sand (Inch)	$5d_{50}$ (Inch)	$6d_{50}$ (Inch)	*Gravel*		*Screen*
			(U.S.Mesh)	**(Inch)**	**(Inch)**
0.005079	0.0254	0.0305	16-30	0.035	0.016

Next do the calculation of the G-S Ratio. The G-S ratio is the ratio between the Gravel grain size and the formation sand grain size. To determine the value (G-S) of this ratio by comparing the size of the Gravel (D50) with the grain size of the sand at 50% of the cumulative weight of the sand (d50). The value of d50 is obtained from Table 1 and D50 is obtained from Table 3, so that the (G-S) ratio can be calculated using **Equation 3**.

$$(G\text{-}S)\ ratio = \frac{Gravel\ at\ 50\ percentile\ (5d_{50})}{Sand\ at\ 50\ percentile\ (d_{50})} \quad (3)$$

Saucier said that the permeability will be stable if the value of (G-S) ratio is 5 to 6. Where if the value of G-S ratio is less than 5 there is a reduction in the permeability of the Gravel Pack because the Gravel Pack is too small to control the sand. Meanwhile, G-S ratio of 6 to 10, there is a reduction in the effective permeability of the Gravel packing. And for the value of G-S ratio more than 10 then the formation sand will freely pass through the Gravel packing. The optimum value of the G-S ratio is 5 to 6 because it appears the bridging function of the Gravel. So Saucier concluded that the optimum ratio of Gravel size to formation sand size between 5 and 6 can be used to maintain packing stability, because the permeability can be maintained in a high state. So that the selection of Gravel and screen sizes on the AR-02 well is correct because it gives a value (G-S) ratio of 5.

Then redesign the production of the AR-02 well. The redesign was carried out because changes were made to the well production equipment, namely the installation of Gravel Packs and screens to overcome the sand problem that occurred. The reset scheme is carried out by observing changes in the optimum flow rate after the Gravel Pack installation. Gravel installation causes a pressure flow loss of 40 psi which results in a decrease in the optimum flow rate from 95 bfpd to 90 bfpd. This causes a change in the productivity index which was previously at a value of 0.198 bfpd/psi to 0.188 bfpd/psi or a decrease in the productivity index of 5.26%.

Furthermore, in the HPU Design, no changes were made to the design of the HPU tool, only a re-calculation was made due to changes in flow rate and productivity index due to the installation of the Gravel Pack. To recalculate the performance of the HPU pump, well data is needed where the depth is 2299.5 m or 7544 ft with a tubing size of 2,441 inches, the pump size is 2 inches with a pump depth of 1740 m or 5708.66 ft and a stroke length of 150 inches. Then in this well using 4 SPM with a Q-test of 96 bpd and a Q design of 90 bpd. This well has a static pressure (ps) of 1200 psi and a pwf of 720 psi with a PI of 0.188 bpd/psi. From these data using the **Equation 4-11**.

$$Imfulse\ factor = 1 + \frac{(SL\ x\ SPM)}{70500} \quad (4)$$

$$Max\ Allowable\ Stress = (22500 + 0.5625\ x\ wt\ of\ fluid)\ x\ service\ factor \quad (5)$$

$$Max\ Allowable\ Range = (Max - Min)\ Allowable\ Stress \quad (6)$$

$$Rod\ stretch\ (inch) = (\frac{12\ x\ Wf}{E})^2\ x\ (\frac{L1}{Ar1})\ x\ (\frac{L2}{Ar2})\ x\ (\frac{L3}{Ar3}) \quad (7)$$

$$Tubing\ stretch = \frac{Weight\ og\ fluid\ x\ Pump\ depth\ x\ 12}{\frac{1}{4}x\ \pi\ x\ DT^2\ x\ 3x10^7} \quad (8)$$

$$Total\ stretch = Total\ stretch\ rod + tubing\ stretch \quad (9)$$

$$Over\ travel = 1.41x(impulse\ factor-1)x(Pump\ depth/1000)^2 \quad (10)$$

$$Plunger\ stroke = SL - total\ stetch + over\ travel \quad (11)$$

$$Pump\ displacement = 0.1166\ x\ plunger\ stroke\ x\ SPM\ x\ plunger\ diameter^2 \quad (12)$$

So that the PPRL results are 15155 lb, MPRL is 7970 lb, the minimum allowable stress is 8,991.59 psi and the maximum allowable stress is 23420.64 psi, then the maximum allowable range is 14429.05 psi with a 5/8 inch stretch rod of 0 inch, stretch 6/8 inch rod by 35.1295 inch, stretch 7/8 inch rod by 17.23 inch, and stretch 1 inch rod by 0 inch, then the total stretch rod is 52.36 inch and tubing stretch is 3.06 inch and total stretch of 55.42 inches. In this well, 0.39 inch of over travel is obtained and a plunger stroke of 94.97 inches and a pump displacement of 135.65 bfpd.

IV. CONCLUSION

Based on the results of the research on the Strategy for Handling the Sand Problem of the HPU Pump in the AR-02 Well, the following conclusions can be drawn:

1. The cause of the sand problem in the AR-02 Well is because the fluid production rate of 96 bfpd exceeds the critical sand flow rate of 66.81 bfpd. The physical properties of reservoir rocks do not cause sand problems because they have a cementation factor of highly cemented (m = 1.99), relatively small clay content (5.4%), compact rock (Δt = 54.16 s/ft), and compact and stable formation rock. (G/Cb = 14.85x1012 psi^2)
2. In tackling the sand problem in the AR-02 Well, Gravel Pack and screen were installed. The correct Gravel size according to the Saucier method is 0.035 inch and the correct screen size according to the Coberly & Wagner, Tauch & Corley, and H. J. Ayre methods is 0.016 inch. The value (G-S) ratio indicates that the selection of Gravel and screen sizes is correct (stable), namely the value (G-S) ratio is at number 5.
3. The redesign of the production scheme due to the installation of the Gravel Pack by using the HPU pump at the same setting resulted in:

- ΔP due to Gravel installation	: 40 psi
- qfluid after Gravel installation	: 90 bfpd (previously 95 bfpd)
- PI after Gravel installation	: 0.188 (previously 0.198)
- Min allowable stress	: 8991.56 psi
- Max allowable stress	: 23420.64 psi
- Total stretch	: 55.42 inch
- Over travel	: 0.391 inch
- Plunger stroke	: 94.97 inch
- Pump Displacement	: 135.65 bfpd

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