PROFESSIONAL TECHNICAL PAPER
ONLINE PRESENTATION
24 - 25 OCTOBER 2020

A Breakthrough in ESP Implementation to Solve Extreme Well Problems

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Abstract. Electrical Submersible Pump (ESP) is an artificial lift that often associated with big production rate. To be able to install ESP, a well should have at least 300 bfpd production rate. ESP well candidates must also have very small amount of base sediment (BS) and quite low GOR, which means ESP does not suit wells with unconsolidated sand reservoir and also high GOR wells. As technology flourished, these requirements for an ESP well are no longer valid. A breakthrough was established for ESP implementation. Nowadays there are some ESP that can withstand extreme well problems such as unconsolidated sand reservoir, high GOR, heavy oil, and slimhole casing.

These extreme wells exist quite a lot in Pertamina EP Asset 1 (PEP A1). JM Structure has unconsolidated sand reservoir with BS number 0.5-40%, NB Structure has heavy oil problem with 10-200 cp reservoir fluid viscosity, GS Structure has gassy problem with 2000 – 4000 scf/stb GOR, and JB Structure has slim hole problem with 4-1/2” casing. PEP A1 face quite challenging condition to produce wells from these structures optimally. This paper will cover Pertamina EP success in handling sand and high GOR problems.

ESP intended to solve sand problem has open impellers, which cause less probability of scale and solids deposition. This open impeller also creates no space between impeller and diffuser, hence no solids accumulation. This ESP is also able to operate in low rate condition, as low as 50 to 60 bfpd. Above 150 bfpd, ESP with conventional type of impellers but with abrasive resistant material is used. To handle high GOR problem, multiphase pump (MPP) is used along with gas separator. MPP stage design has axial screw type impeller and gas handling diffuser. Gas from reservoir fluid will be compressed and be broken into smaller bubbles resulting in homogenous gas-liquid mixture, hence no gas lock during production. Pertamina EP has successfully installed both ESP types in JM and GS structure with sight to install ESP for heavy oil and slim hole casing in the near future.

ESP for sand problem were installed in well JM-134 (open impeller) with 10% - 50% BS and JM-25 (abrasive resistant material) with production rate around 600 bfpd of JM Structure. ESP for high GOR were installed in well GS-1 and GS-15 of GS Structure. Both wells has around 2000 scf/stb GOR. In total, these four wells have been producing 4706 bbls and counting. It shows that these two types of ESP have successfully handled sand and high GOR problems in PEP A1.

The successful implementation these two types ESP shows that a breakthrough has been made in ESP implementation, which makes old stereotypes about ESP well that were mentioned above are now obsolete.

Keyword: ESP, Extreme Well, Sand Problem, High GOR, Electrical Submersible Pump, Gassy

1 Introduction

Producing wells' fluid to surface is the main task for production engineers. Every well has its own characteristic and behavior that production engineers need to identify. After the identification, suitable lifting method will be selected to produce the well. Engineers' life are easier when wells can produce naturally using their own energy. But, once that energy fades, artificial lift will be needed to enter the picture. As common knowledge, there are several artificial lifting method that can be selected: gas lift, sucker rod pump (SRP), progressive cavity pump (PCP), electrical submersible pump (ESP), and other methods that are modification or combination of these four methods. Selection of lifting needs to consider inflow performance relationship (IPR), gas produced, inclination, well's trajectory, base sediment (BS), cost, and many more.

ESP is a multistage centrifugal pump that offers a great deal of flexibility and is capable of producing very high volumes of liquid, can be used efficiently in deeper wells than sucker rod pumps, and are able to handle some free gas in the pumped fluid (Economides et al, 2013). When talking about ESP, it is often associated with high production fluid rate. A well will need at least 300 bfpd for ESP to be considered. Conventional ESP has constraints in gas rate and BS number. In other words, ESPs are especially effective in wells with low bottom hole pressure, low gas/oil ratio, low bubble point, high water cut or low API gravity fluids (https://www.pumpsandsystems.com/electric-submersible-pumps-oil-and-gas-industry). However, as technology flourished, those constraints are now ancient. ESP has been improved and modified to be able to manage all of those handicaps.

Pertamina EP Asset 1 (PEP A1) has quite a lot of wells with extreme problem. These wells dwell in Field Ramba and Jambi. JM Structure is located in South Sumatera and produces 350 bopd, contributing 15% of Field Ramba production PEP A1. This oil structure produces from Palembang Formation in 300 – 400 m depth. Like other shallow prospects, this formation also has unconsolidated sand problem. BS number in this structure ranges from 0.1 – 50%. Amidst this problem, almost all well from JM Structure still has prospect of oil from history or production log. GS Structure is located in Jambi Province and is one of main structures in Field Jambi. This structure produces 1000 bopd and consists of 29 wells. Main problem that needs to be handled is its high GOR (more than 2000 scf/stb). Producing high GOR is really challenging. Gas pound that ultimately leads to fluid pound found with sucker rod pump lifting, while gas lock is the problem when conventional ESP is used. A technically sound and reliable lifting are needed to handle these two problems.

Well JM-134 was drilled on May 2019 and produced oil with peak production of 75 bopd. Due to PEP A1's commitment to SKKMigas, a sand control job was performed on July 2019. This production and activity history are shown in Figure 1.

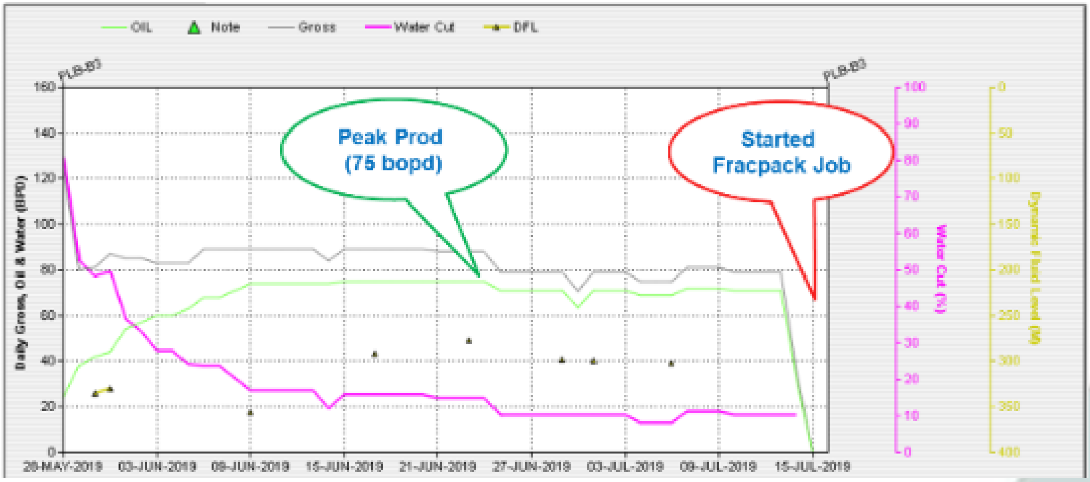


Figure 1 Production and Activity History Well JM-134

Fracpack operation has been performed safely and meet the design accordingly. There were a minor incident where 1 ea pump safety disk broke when pumped 10 ppg sand slurry, but Immediate action was taken to close discharge blender valve that connect to that burst disk pump. Other than that operation was successful. Figure 2 and Figure 3 show fracpack operation pump chart and fracture geometry chart.

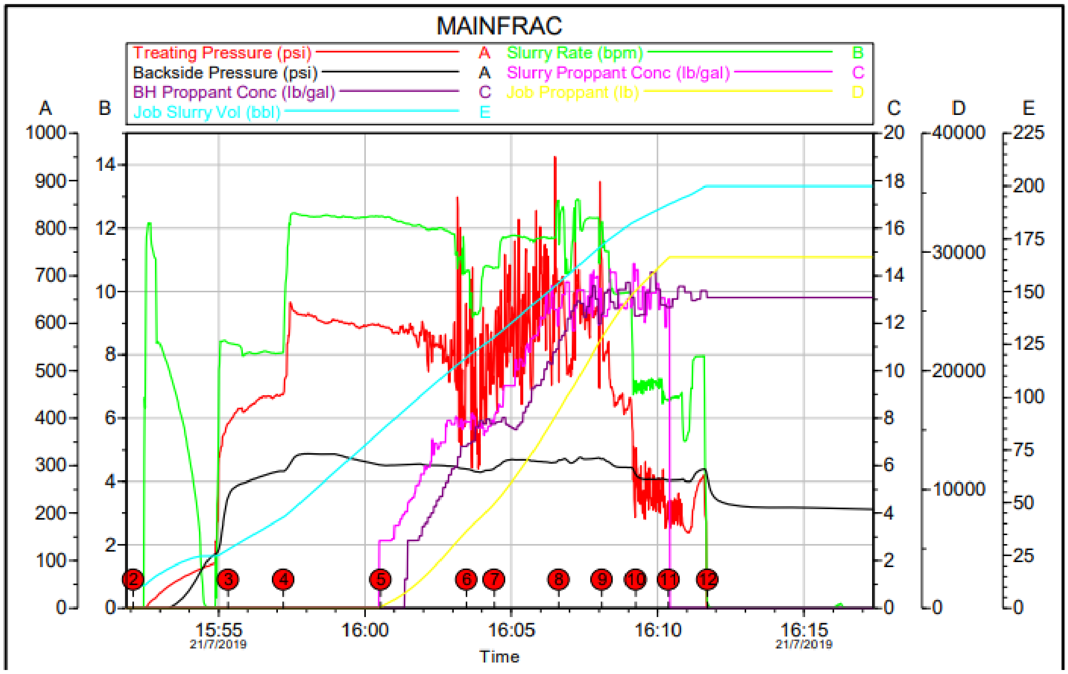
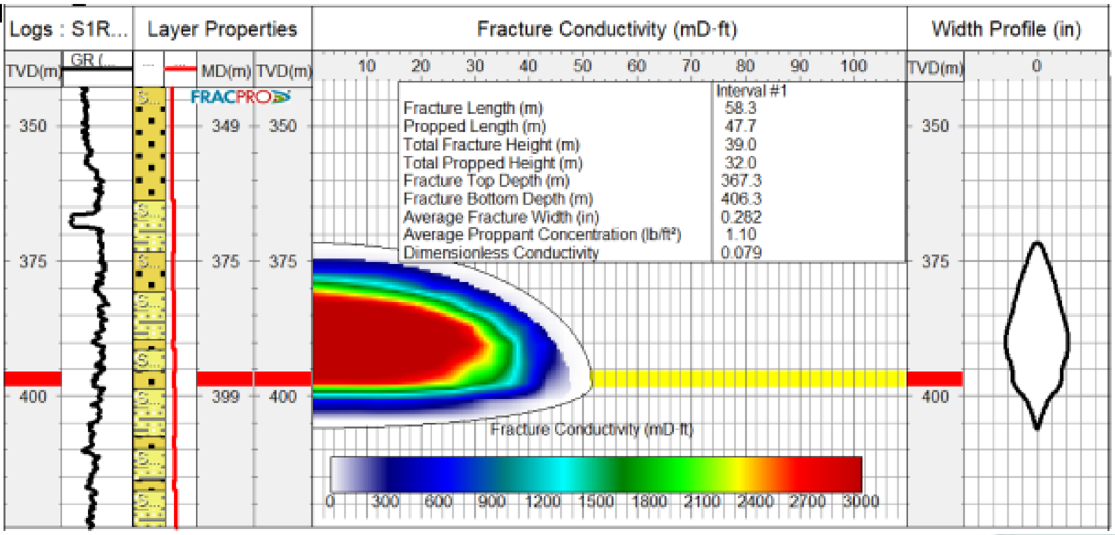


Figure 2 JM-134 Fracpack Pump Chart



	Interval #1
Fracture Length (m)	58.3
Propped Length (m)	47.7
Total Fracture Height (m)	39.0
Total Propped Height (m)	32.0
Fracture Top Depth (m)	367.3
Fracture Bottom Depth (m)	406.3
Average Fracture Width (in)	0.282
Average Proppant Concentration (lb/ft²)	1.10
Dimensionless Conductivity	0.079

Figure 3 JM-134 Fracture Geometry Shape

After this job was where the drama began. Artificial lift chosen for this well was SRP. However, this lifting method was not able to produce the well because sand was stuck in its traveling valve. It created leak in the valve, hence no fluid can be produced to surface. PCP had also been tried for this well, but due to no compatibility test with well's fluid the effort failed miserably. There were still no fluid came to the surface. The silver line was that when swab job was performed, the result showed that there were still influx from the reservoir. Fluid from swab job was analyzed and compared to the fluid before fracpack was performed, and it showed that there were an increase in BS number. Average BS number for this well before fracpack Figure 4 shows production history after fracpack. Figure 5 to 7 show signs that showed this well was still "alive" and all that it needed was a suitable lifting method to be able to produce.

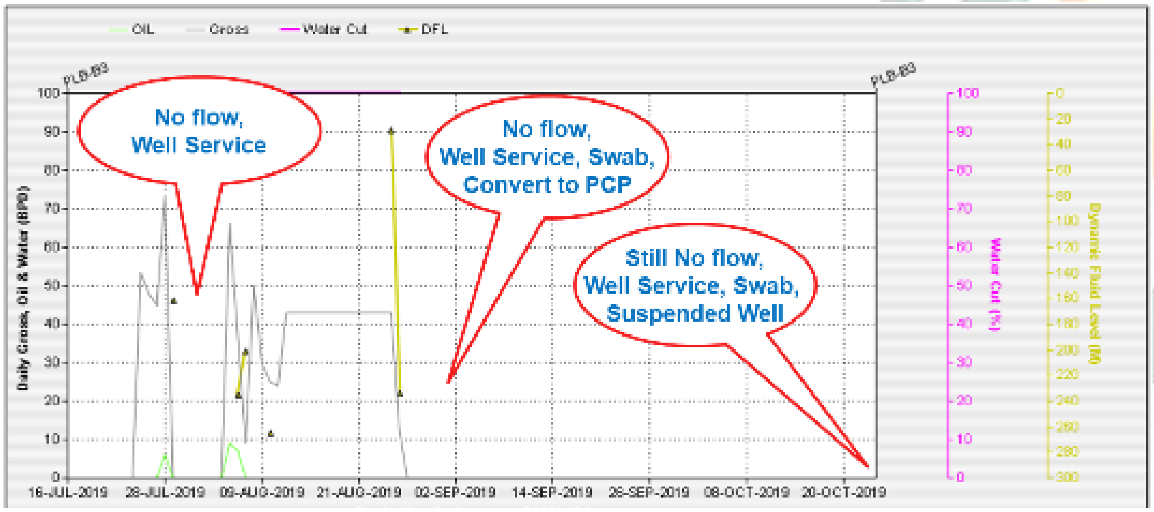


Figure 4 JM-134 Production History after Fracpack

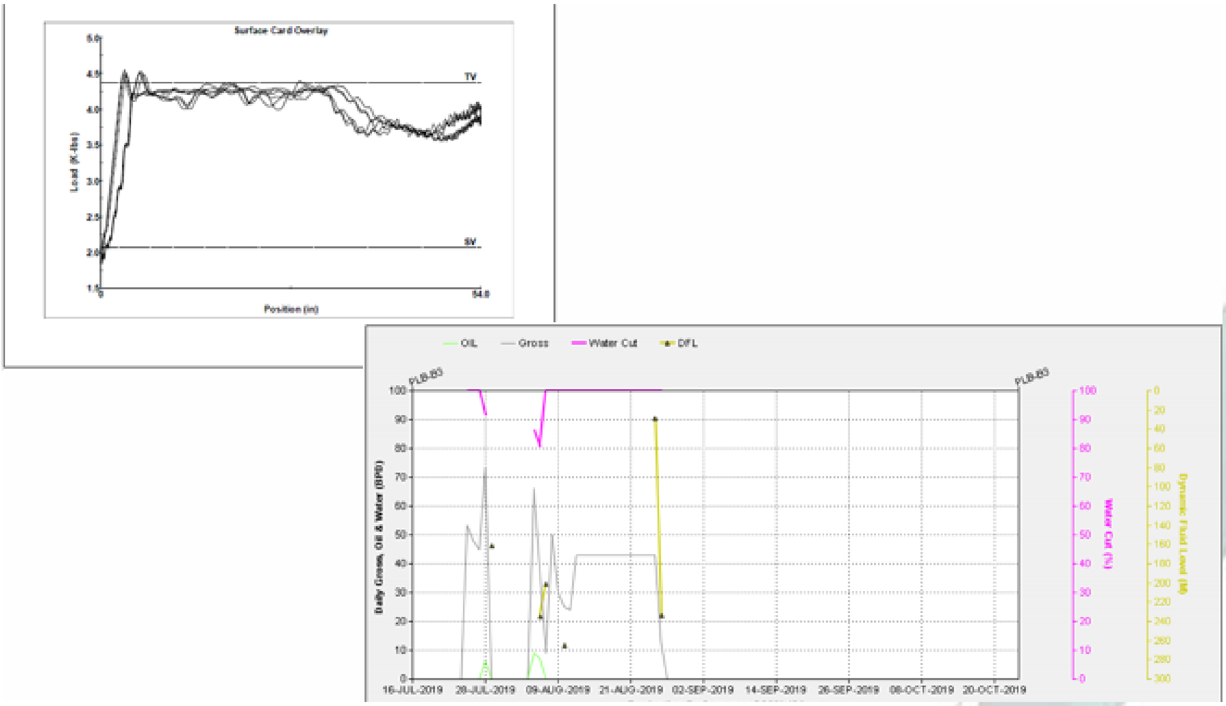
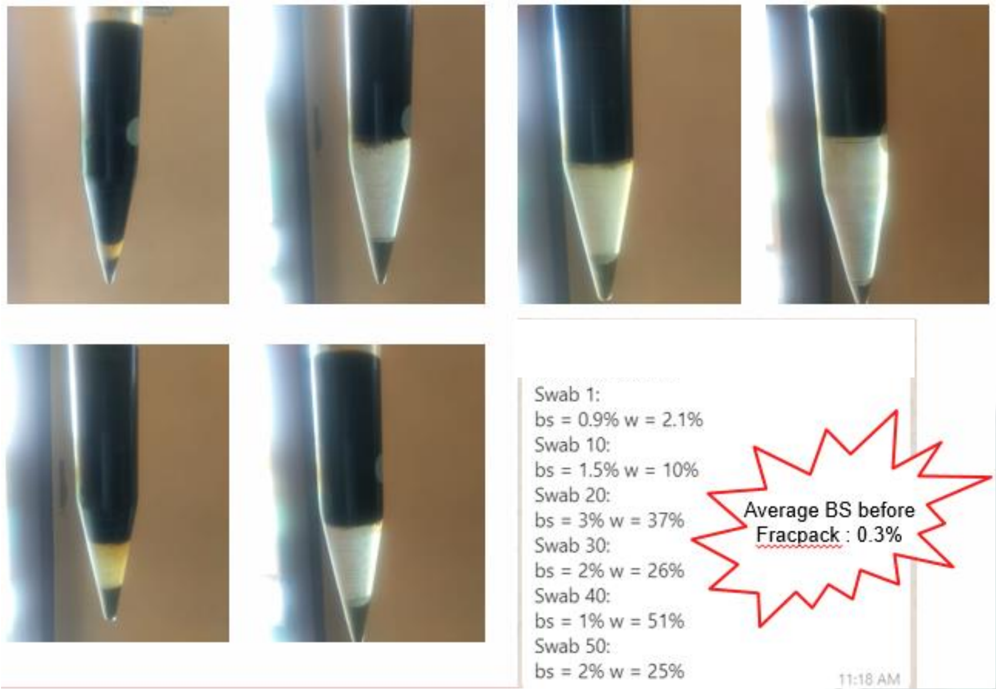


Figure 5 Dynagraph showed fluid pound but fluid level survey showed that there was reservoir influx

Figure 6 Swab job also showed reservoir influx



Swab 1:
bs = 0.9% w = 2.1%
Swab 10:
bs = 1.5% w = 10%
Swab 20:
bs = 3% w = 37%
Swab 30:
bs = 2% w = 26%
Swab 40:
bs = 1% w = 51%
Swab 50:
bs = 2% w = 25%

Average BS before Fracpack : 0.3%

11:18 AM

Figure 7 Fluid analysis showed that there was an increase in BS number

A little bit different than JM-134, JM-25 had less BS number than JM-134 but with higher production rate (around 800 – 1000 bfpd). The problem with JM-25 was production lifetime. The longest lifetime this well had was three months. Figure 8 shows JM-25 production performance.

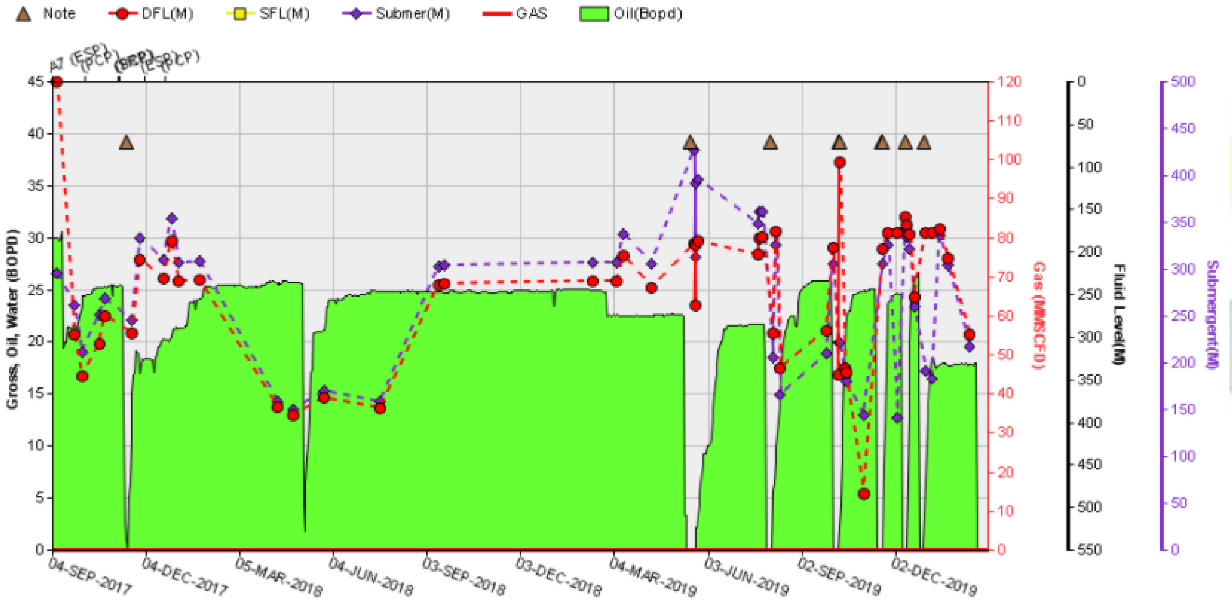


Figure 8 JM-25 production performance

In can be seen in Figure 8 that from May 2019 until March 2020, there are at least 8 well service jobs and short lifetime. A more suitable lifting method was needed to solve this problem and even optimize the well.

In GS Structure the problems that is faced is gassy wells. Some wells are producing under gas pound / fluid pound condition. SRP and conventional ESP lifting are under threat of gas lock. Well GS-1 was a natural flow well with peak production of 346 bopd. As time goes by, right about one month of production, the well was declining and finally couldn't be produced naturally anymore. Figure 9 shows well GS-01 production performance.

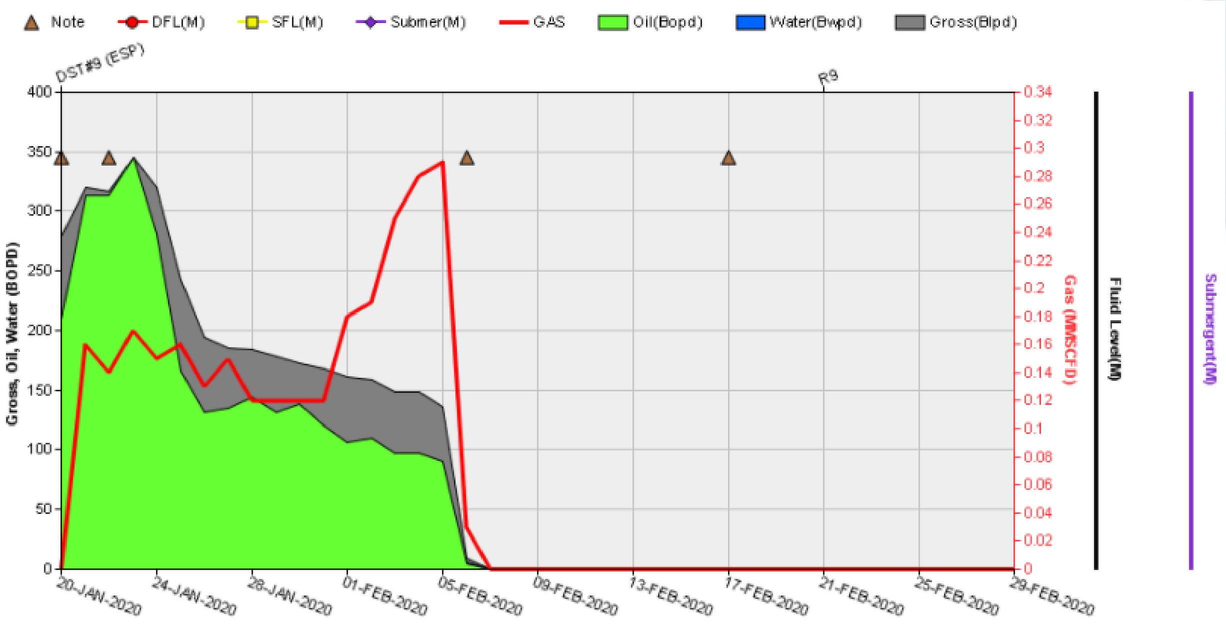


Figure 9 GS-1 production performance

In order to attempt to restore GS-1 production, nitrified acid job was performed using coiled tubing unit (CTU). HCl 32% was used in this job, because based on its well history this GS-1 well was completed using $CaCl_2$ as its CF and the well was suspended for a few years before put in to production on January 2020. Suspending the well for a long time caused $CaCl_2$ to precipitate, moreover its water contained bicarbonate (HCO_3) that can cause $CaCO_3$ to form. Table 1 shows formation water analysis for Well GS-1.

Ion	mg/1	mgeq/1	% react, value
Natrium Na+	5408.68	235.16	48.99
Calsium Ca++	12.00	0.60	0.13
Magnesium Mg++	51.56	4.24	0.88
Karbonat CO3=	0.00	0.00	0.00
Bikarbonat HCO3-	2440.00	40.00	8.33
Sulfat SO4=	0.00	0.00	0.00
Chlorida Cl-	7100.00	200.00	41.67
Besi, Fe+++	0.00	0.00	0.00
Total Dissolved Ion	**15012.24**	**480.00**	**100.00**

Table 1 Formation water analysis for Well GS-1

However, after nitrified acid job was performed the well was still not able to flow naturally. Since the well near February 2020 produced 0.28 MMSCFD gas and 98 bopd, its GOR was more than 2000 scf/stb. Gas lock problem using SRP or conventional ESP was unavoidable with this high number of GOR.

GS-15 also experienced this high GOR problem. This well produced just above 0.1 MMSCFD with about 40 bopd of oil (GOR around 2000 scf/stb). Figure 10 shows Well GS-15 production performance.

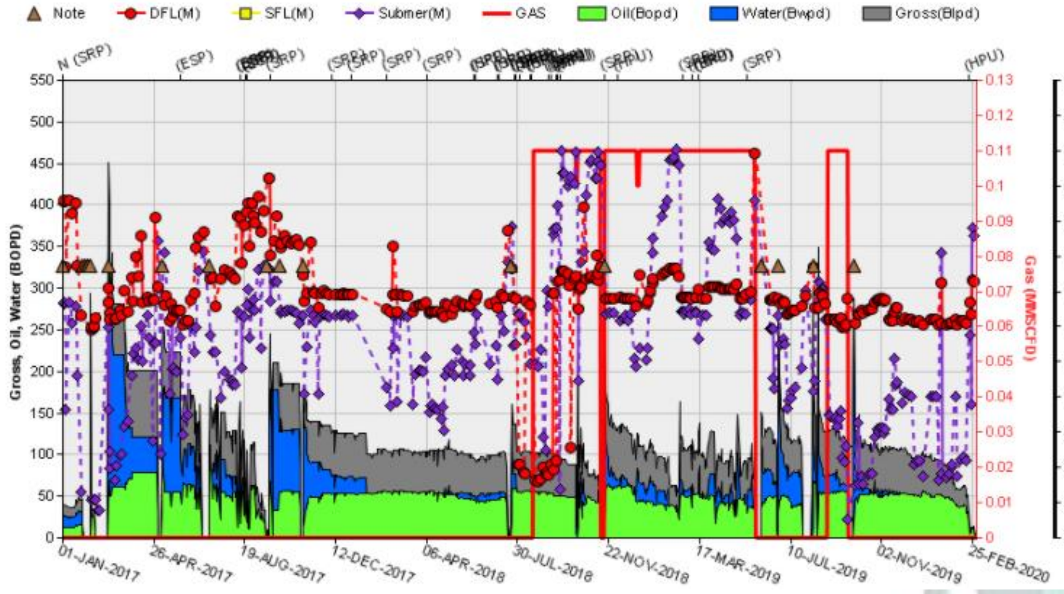


Figure 10 GS-15 production performance

It can be inferred from figure 10 that as soon as gas kicked in, well's lifetime was also shortened. The gas kicking in started when fracturing was performed in this well on February 2017 due to new layer's low influx. The fracture grew through the layer above producing one. This accidentally fractured layer unfortunately contains gas, therefore after fracturing job the well was produced as well as the gas consequently with much higher GOR. Since gas lock was inevitable by producing the well using conventional ESP and SRP, other lifting solution method was needed to enter the picture.

2 ESP for Extreme Wells

2.1.1 ESP High Solid Content (Abrasive Resistant Material)

ESP High Solid Content (Abrasive Resistant Material)

ESP high solid content for extreme well was chosen as solution for the problem in JM-134, but before this kind of ESP is discussed, here is a brief picture on why conventional ESP failed to handle wells with sand problem. Figure 11 shows impeller and diffuser design for conventional ESP.

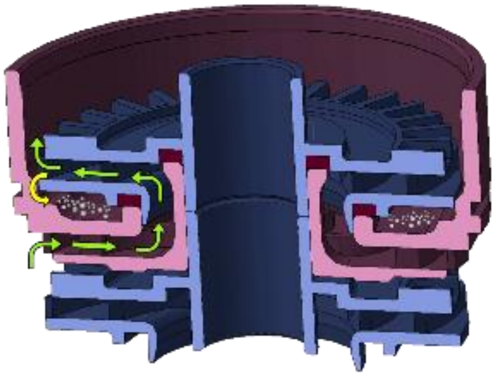


Figure 11 Conventional ESP design

The design in conventional ESP made itself susceptible to solids and scale deposition also prone to gas lock for wells with high GOR. Deposition of solids and scale clogged the space between impeller and diffuser, hence pump stuck. This is where special trait from ESP high solid content works.

ESP high solid content has open impellers, shown in Figure 12, which cause less probability of scale and solids deposition. This open impeller also creates no space between impeller and diffuser, hence no solids accumulation. This ESP is also able to operate in low rate condition, as low as 50 to 60 bfpd like what shown in its pump curve in Figure 13 and 14.

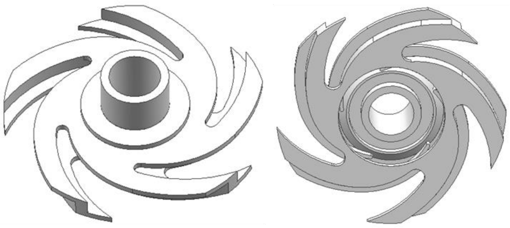


Figure 12 Open impeller design for ESP high solid content

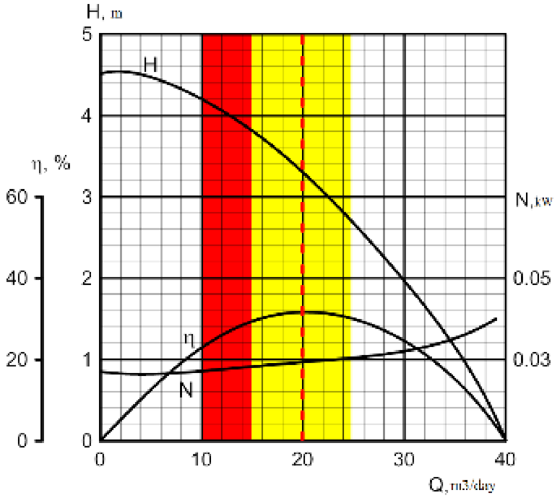


Figure 13 ESP high solid content pump curve (Ageev et al, 2014)

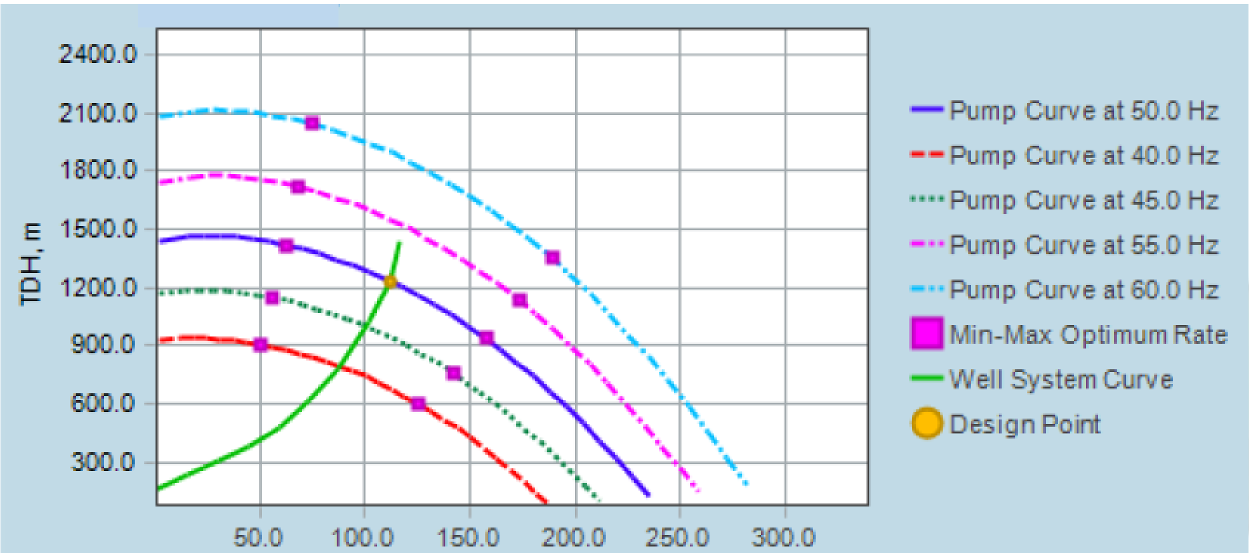


Figure 13 ESP high solid content multi head pump curve

For wells that have production rate above 200 bfpd but also have sand problem, impeller design will be the same as conventional but the material for the ESP assembly is abrasive resistant. It makes sense, as the fluid is more dominant than solid, BS number will decrease. Therefore conventional type of impeller will not be a problem here, the focus is turned to the pump material.

ESP for High GOR Wells

Common knowledge for production engineering is gas is an enemy to ESP. But to annihilate gas from well is impossible, so tools to handle gas is absolutely needed. Default solution for gas handler is the gas separator. When people mention gas separator it usually refers to static gas separator that only uses reverse flow method (reversing gas flow to the annulus). It can handle 20% of free gas (https://production-technology.org/esp-pump-intake/). Next level gas separator is the Advanced Gas Handler (AGH) that can handle up to 50% of Gas Volume Factor (GVF). This type of gas separator works by this sequence:

1. Gas is broken, grinded, and compressed into solution in the axial stage.
2. Compressing the gas reduces its volume and increases its elasticity, helping to stabilize the fluid.
3. The stable mixture enters the labyrinth stage, where it undergoes even more intensive grinding.
4. This process repeats as the fluid-gas mix flows through the sequential stages, increasing homogenization and consistency so that it can easily pass through the pump.

AGH increases the uniformity of the fluid entering the pump. This improves ESP operation and efficiency by reducing vibration and pulsing. As the fluid exits the ESP, free gas is released from the homogenized mixture. It expands out of solution and actually provides additional lift for reservoir fluids. In general, the use of a gas handler helps improve ESP operation and efficiency (https://www.novometgroup.com/products-services/artificial-lift/intake-and-gas/advanced-gas-handler/).

The most sophisticated gas handler so far is multiphase pump (MPP). This is the primary tool that is used in ESP extreme well for high GOR. MPP can handle free gas up to 75%. It consists of an axial type impeller and diffuser. Figure 14 shows this axial type impeller and gas handling diffuser.

Figure 14 Axial type impeller and gas handling diffuser of an MPP (Peshcherenko et al, 2014)

Operation sequence of MPP is as follow:

1. Flow streams to the axial type impeller that results in compressed gas volume.
2. Compressed gas streams to the diffuser and this gas bubbles break into smaller bubbles.

This operation sequence results in homogenous gas-liquid mixture. Figure 15 shows how MPP works.

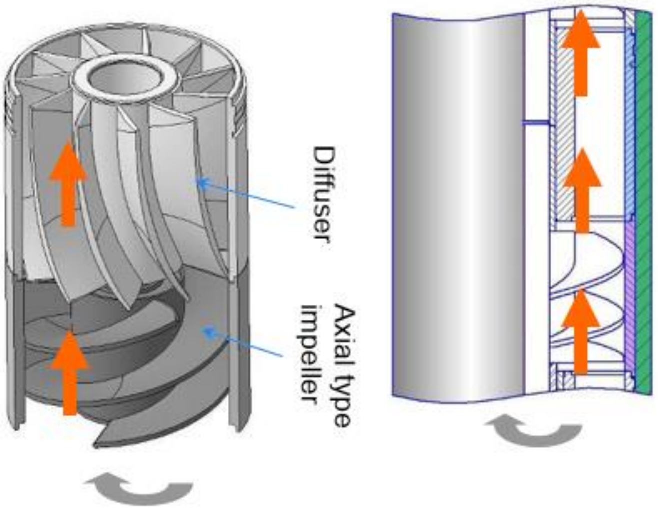


Figure 15 How MPP works

Benefits of MPP:

- Increased production and reservoir life in gassy wells by increasing drawdown and allowing effective pump operation at lower intake pressure
- Increased production by reducing gas locking production shutdowns
- Improved installation Run life by stabilizing motor current

3 Result and Discussion

3.1 JM-134 Using ESP High Solid Content

ESP installation was performed on late October 2019. Immediate result was gained after installation. Under extreme condition this well could fluid to surface. At the beginning of production BS number for this well as high as 50% as shown in Figure 16. Well JM-134 produced peak production of 60/55/8% at June 21st 2019. Cumulative production gained from this project is 1278 bbls. Figure 17 shows production history of this produced well after installation.

Figure 16 BS for Well JM-134 as high as 50%

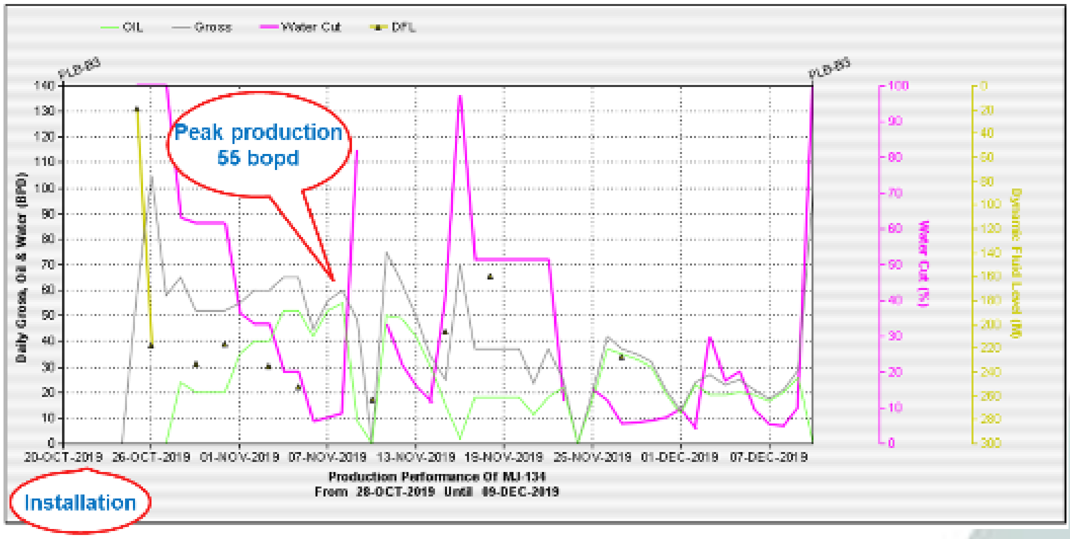


Figure 17 JM-134 production history after ESP high solid content installation

As time goes by, sand problem in JM structure, especially in this well, is really severe. Depleted pressure of the formation resulted in increasing of sand blocking perforation decrease in influx. On February 1st, 2020, well intervention was performed in this well to change producing zone.

If sand problem really severe, ESP for high solid content can't work on its own. Combination of sand control method from the reservoir, lifting type, and surface sand trap need to be performed for optimal production.

3.2 JM-25 Using ESP Abrasive Resistant

Installation of ESP abrasive resistant in this well is proven to be a success. Figure 18 shows performance production of Well JM-25.

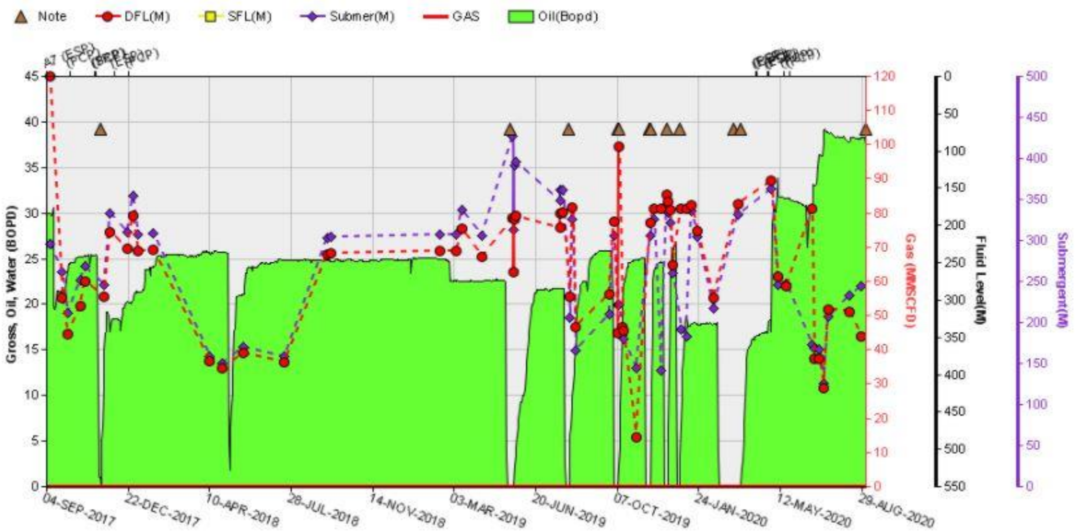


Figure 18 JM-25 production history after ESP high solid content installation

ESP abrasive resistant was installed on March 21st 2020. It can be seen from Figure 18 that it shows improvement in production by getting some gain in production rate and also in cumulative production. Well's lifetime is also improving with 5 month and still producing now. Peak production was on July 12th, 2020, on 39 bopd. Last production on September 4th, 2020, was still on 38 bopd. Cumulative production since installation is 4984 bbls and counting.

3.3 GS-1 Using ESP for High GOR

Another success in ESP extreme well installation was in Well GS-1. ESP for high GOR is able to get Well GS-1 back on production. Opportunities for upsizing the well is also opened based on production and intake pressure trend. Peak production was on May 19th, 2020, on 106 bopd. Cumulative production so far is 13025 bbls and counting. Figure 19 shows production performance of this well.

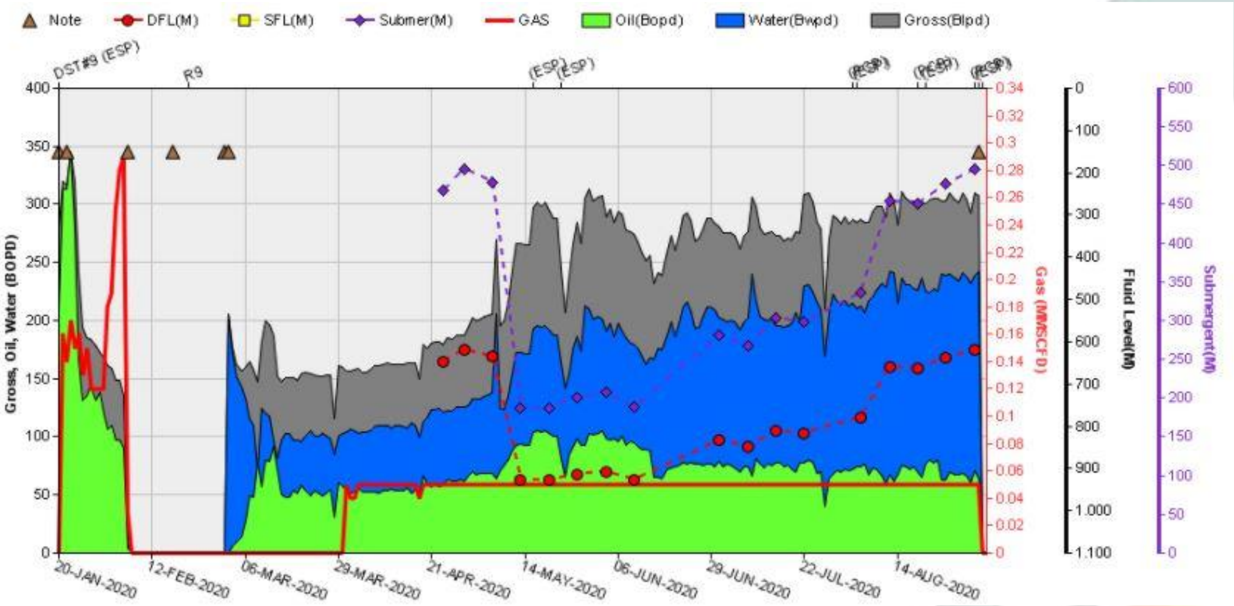


Figure 19 GS-1 production performance

Figure 19 tells that not only well is back on production, there is also improvement in well's fluid level/submergence based on downhole sensor intake pressure (Pi) reading. This increase in Pi/submergence opened the door for increasing frequency or even upsizing the pump. Right now the pump operating on 70 Hz frequency but submergence is still quite high to be optimized. Thus, upsizing the pump is the next step for this well.

3.4 GS-15 Using ESP for High GOR

ESP for high GOR in this well got a mixed evaluation. Figure 20 shows production performance for this well.

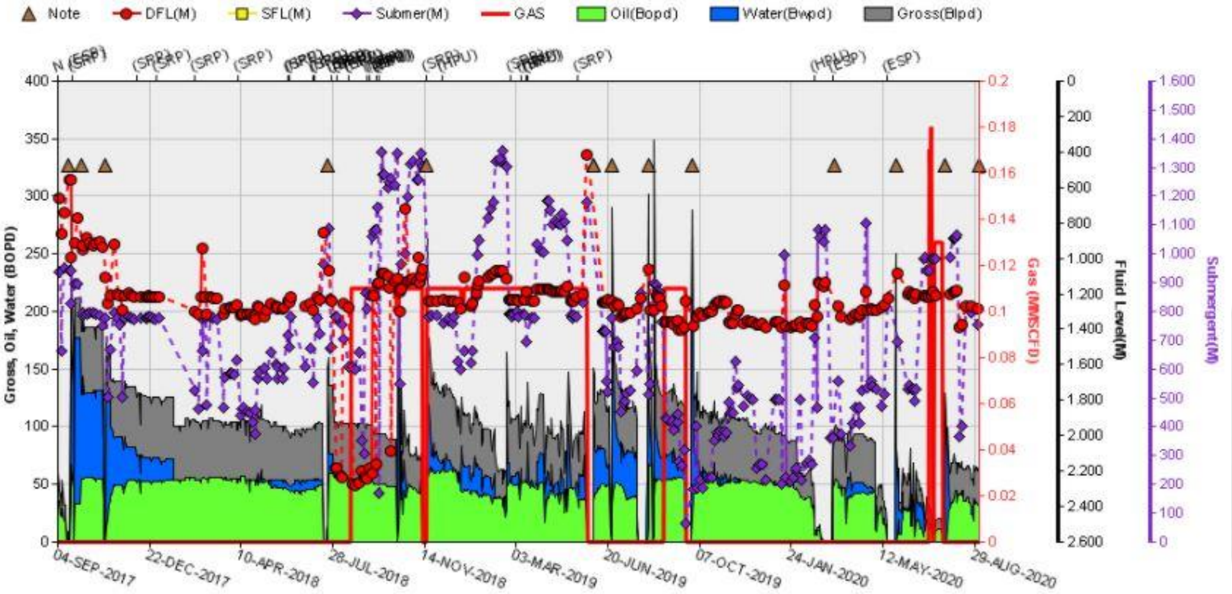


Figure 20 GS-15 production performance

It can be inferred from Figure 20 that ESP for high GOR wells can handle GOR for this well. However there is one more handicap from this well in using ESP. e.g. scale. After installation on March 21st, 2020, there were two well services that needs to be done on this well. The first well service was needed because production keep declining and Pi keeps increasing, meaning scale deposition was formed. Figure 21 shows scale deposition from pulled pump in GS-15.

Figure 20 Scale deposition in pulled pumped Well GS-15

After getting this data, scale preventer for this well was added into two sections instead of one. However there was an indication of tubing leak shown in Figure 21.

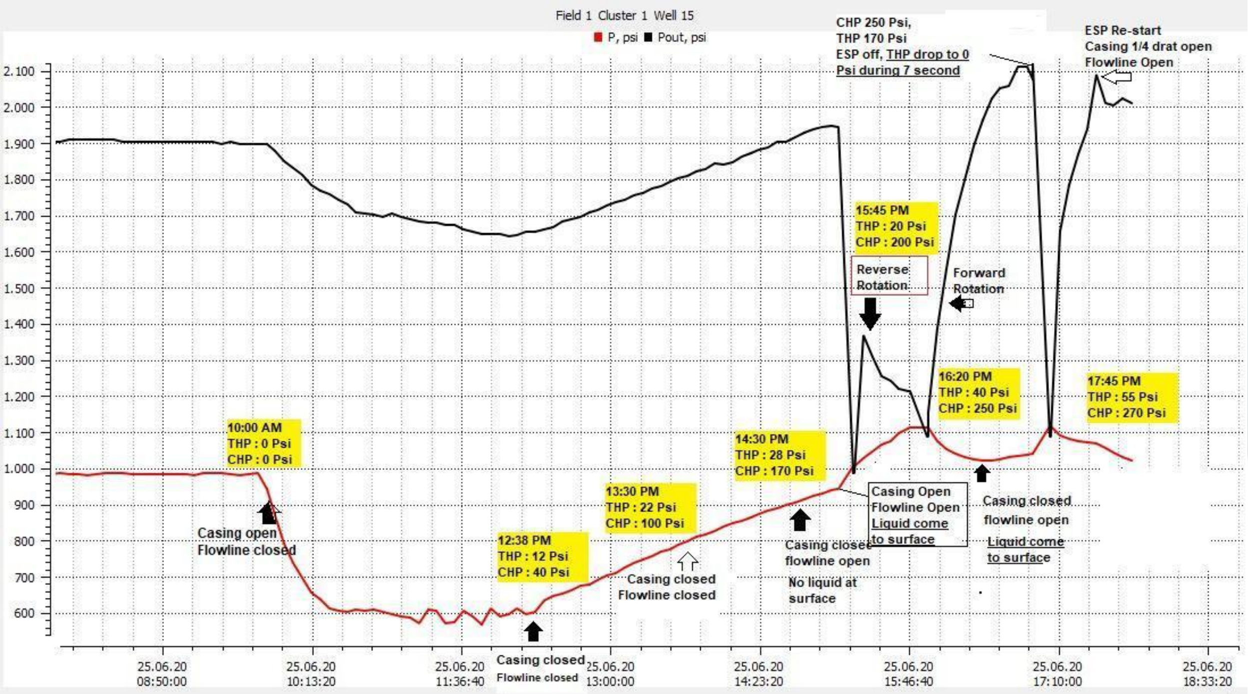


Figure 21 GS-15 tubing leak indication

When the second well service was done, tubing leak was found on two position as shown in Figure 22.

Figure 22 Tubing leak in Well GS-15

After the second service Well GS-15 is producing quite well. Peak production of this well was on March 16th, 2020, with 55 bopd. Cumulative production since first installation is 4575 bbls and counting.

Looking at peak production was no better and even for shorter period of time compared to before ESP for high GOR installation, there are two conclusions that can be inferred. The first one is depletion of producing layer. This N1 layer is producing quite massive recently through new discovery from 2 newly drilled wells and 3 workover wells, so it makes sense that reservoir pressure and well's production are decreasing. Second conclusion is that the search for suitable lifting method for this structure is still need to be explored.

4 Conclusion

Installation of ESP extreme well in these four wells are quite successful, especially in Well JM-25 and GS-1 that contribute to at least 20000 bbls. In JM-134, even though ESP high solid content was able to revive the well and got 1278 bbls cumulative oil, the severity of sand problem and pressure depletion call for combination of efforts from subsurface, lifting, and surface efforts. Sand control stimulation for the reservoir, ESP high solid content for lifting, and suitable sand trap at surface will be options to explore. In GS-15, ESP high GOR was proven capable to handle high GOR wells and getting more than 4500 bbls. However, since production is still less than previous period before ESP for high GOR installation, BHP survey confirmation needed for how far reservoir pressure has been depleted. Possibilities in exploring other lifting method that is more suitable than ESP for high GOR are still opened and worth considering.

This success breaks down walls of limitation that previously labelled on ESP implementation. Sand problem, low rate, gassy, small clearance casing, and other problems that seemed impossible to be solved by ESP before, have become feasible. This technology need to be explored further. For the next step in Pertamina EP, other candidates for ESP high solid content and ESP for high GOR await. There also some candidates for other ESP extreme well technology such as slimhole ESP, ESP for high viscous oil, and through tubing ESP. This lifting type is evolving, and production engineers need to adapt to its evolution.

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