GEOTHERMAL WELLS DISCHARGE INITIATION USING AIR LIFT AND AIR COMPRESSION: CASE STUDY WITH AND WITHOUT DOWNFLOW IN THE WELLBORE

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ABSTRACT

During the exploration phase of Rantau Dedap geothermal field located in South Sumatra, Indonesia, 2 wells (namely X-1 and X-2) were drilled from the same pad by Supreme Energy Rantau Dedap (SERD). After respectively 3 and 2 months under shut-in conditions, decision was taken to discharge these wells in order to accelerate the heating-up process. These two wells present similar temperature, but their respective completion tests have shown that a downflow is occurring in the wellbore of well X-1 while it is not the case in well X-2. Furthermore, attempts of simply opening the master valve to discharge these wells were not sufficient, and thus stimulation methods were required to do so. This particular situation gives a good opportunity to assess the effectiveness of the different types of discharge initiation such as air lift and air compression, for wells with and without downflow.

This paper describes in details the sequence of operations and the associated well behaviours during the various attempts to discharge wells X-1 and X-2, both using air lift and air compression methods. The results show that improving the procedure for initiating discharge using air compression increased the probability of a successful discharge of the well. In addition, the different attempts on well X-1 raise some concerns about the use of air lift for a well presenting a downflow in its wellbore.

Putting into perspective the cost and the operational issues of each of these methods, this paper aims to provide appropriate solutions to initiate well discharge under particular configurations and provides a better methodology to ensure a safe and successful well discharge stimulation.

1. INTRODUCTION

Initiating the discharge of high enthalpy geothermal wells is generally not a major issue: steam or cold gas may accumulate in the top part of the casing and develop sufficient shut-in wellhead pressure so that the simple opening of the flow control valve will initiate the flow. However, assistance to flow may be required in the case of low pressure single-phase liquid wells or if there is a cold section in the upper part of the wellbore. Different techniques and practices are available to stimulate such wells and initiate the discharge, and many considerations need to be taken into account in order to achieve safe and efficient flow initiation at minimized cost.

In 2014, Supreme Energy, GDF Suez and Marubeni have started the exploration drilling of Rantau Dedap green field geothermal project in South Sumatra (Figure 1). The two first exploration wells (namely X-1 and X-2) were drilled from the same pad and both required stimulation to initiate the discharge. Despite similar temperature and pressure regimes, these two wells present different feed zones characteristics, and thus allow to make very particular observations to assess the two stimulation of discharge initiation tested: air lift and air compression.

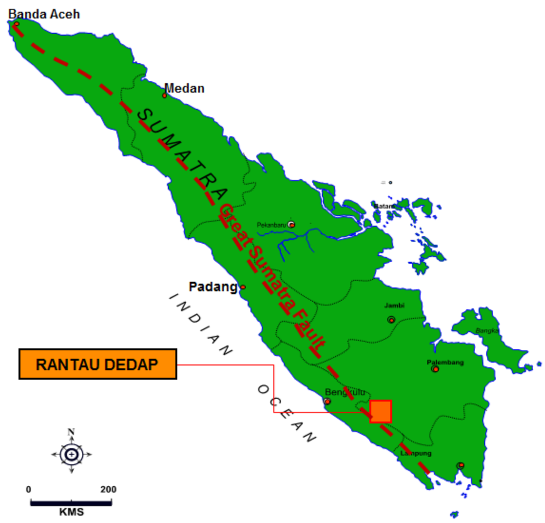

Figure 1: Rantau Dedap prospect location

2. SEQUENCE OF OPERATIONS

2.1 Well X-2

During well X-2 completion test, two main feed zones were identified at 736 and 626 masl, for a total injectivity index of about 9 kg/s.bar. To evaluate the possibility to discharge well X-2, a Pressure Temperature (PT) profile was carried out before the stimulation attempt. This profile showed that the pressure at the first feed zone was 52 bara and that according to Sarmiento's methodology (1993), considering the areas A_c representing the amount of missing energy to initiate flashing in the top part of the wellbore and A_f representing the available energy for flashing once the well has been compressed down to the first feed zone, the well would most likely not discharge with air compression method since the ratio A_f/A_c was clearly less than 0.7, as shown in Figure 2.

When using this methodology, one shall carefully check that the recorded temperature truly represents the equilibrated temperature in the well, especially in the production casing section, where flashing can be triggered if any leakage occurs at the tool lubricator during the PT logging. For well X-2, the comparison of log down and log up runs indicated that the temperature profile matching the saturation curve between 1510 and 1315 masl was not due to a pressure drop in the well during the logging, but truly reflected the static condition of the well.

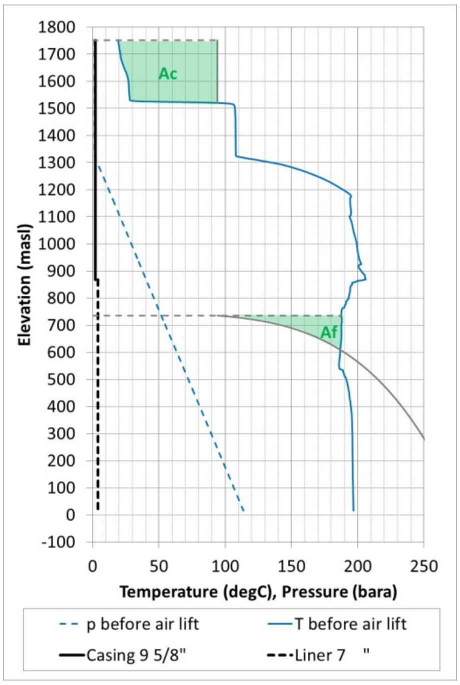

Figure 2: Well X-2 PT profile before discharge initiation

2.1.1 Air lift

Therefore, decision was taken to stimulate the well by using air lift technique, directly with the rig and drill string (made of 5 in., $3^{1/2}$ in. and $2^{3/8}$ in. joints) which were available at that time. As a common practice, the first attempt of air lift was carried out at 800 masl so that the height of lifted fluid (ie. from the depth of injection to the water level in the well) was equal to the height of nearly-vacuum condition in the well (ie. from the water level to the wellhead), in order for the reservoir fluids to reach the surface. Under this configuration, the well flowed after the maximum air rate (2300 scfm) was reached, the wellhead pressure (WHP) getting stabilized at 2.8 barg under continuous air injection (Figure 3). However, once the air injection was reduced and stopped, the well flowed at 0.1 barg and produced water only (condensation product) for about 4.5 hours.

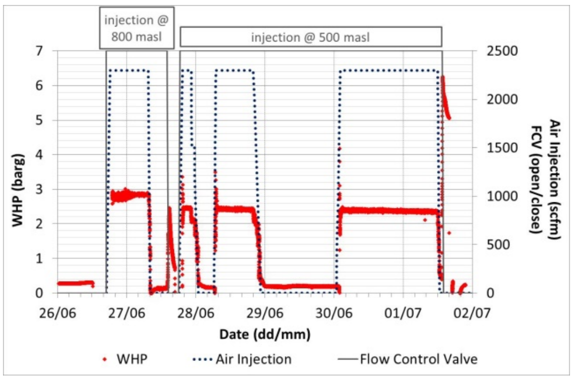

Figure 3: Well X-2 discharge attempt with air lift

The first attempt being non successful, the Flow Control Valve (FCV) was closed and the drill string was run deeper, at 500 masl, ie. about 100 m below the last feed zone (striping down was exceptionally allowed since the well was not developing any pressure at the wellhead). Three attempts were carried out under this configuration, all leading to a well flowing with a WHP of 2.4 barg under continuous air injection (2300 scfm), but again water only being produced with a WHP of 0.2 barg (for about 5 and 27 hours) once the injection had stopped. Therefore, it was not possible to make well X-2 continuously flow using air lift with the drill string.

2.1.2 Air compression

However, this attempt with air lift was not considered as a failure since the PT profile that was recorded after under shut-in condition (Figure 4) showed that some of the permeable section got heated up (the rest of the section got cooled down because of cold water influx from the brine that was being re-injected at the same time in well X-1). But the most significant benefit of this first attempt with air lift was the heating up of the top part of the casing, where the fluid in the wellbore reached the conditions of saturation (bleeding the cold gas accumulated at the top before the air lift had not allowed to do so because the influx from the reservoir was too small to induce continuous steam flow up to the surface).

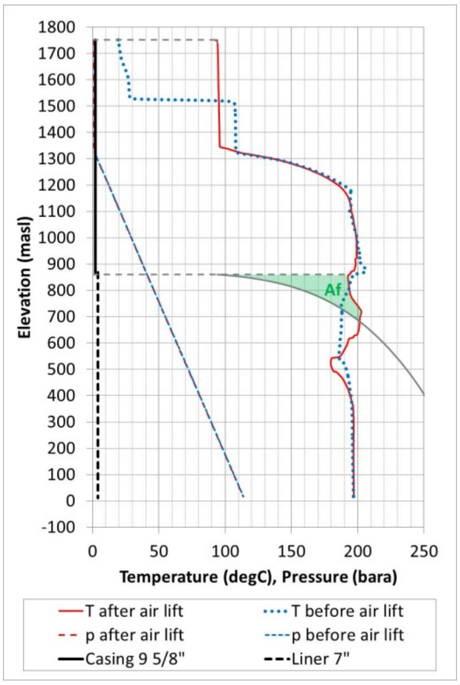

Figure 4: Well X-2 PT profile 1 day after discharge initiation

Consequently, the area A_c was reduced to 0 and the ratio A_f/A_c was tending to infinite, giving the well high chance to flow by using air compression. Therefore, decision was taken to try to discharge well X-2 by using this stimulation technique. 24 hours after the well had been put under shut-in condition, the first attempt of air compression was performed by injecting air through the wing valves. As shown in Figure 5, the WHP reached a maximum of 42.3 barg (43.1 bara), compressing down the water level just below the casing shoe, around 860 masl (taking into account the pressure drops in the wellbore), where a possible permeable zone was identified during the first Pressure Temperature Spinner (PTS) survey run under injection condition. This was 100 m shallower than expected, which actually led to a bigger area A_f, and still having the ratio A_f/A_c tend to infinite. Fifty minutes after the WHP had reached its maximum, the FCV was opened and the well was able to continuously discharge (immediately) with a WHP of 2.9 barg.

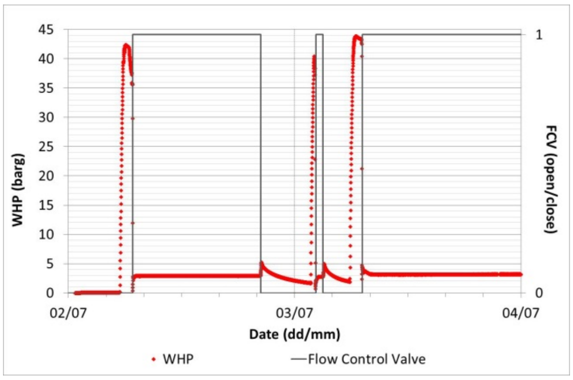

Figure 5: Well X-2 discharge attempt with air compression

After 13.5 hours of continuous flow, the discharge initiation was considered a success and the FCV was closed in order to remove the Blow-Out Preventer (BOP) and some equipment to free the rig that was still mobilized after the air lift attempt. A second attempt of air compression was carried out successfully (WHP reached 40.4 barg, or 41.2 bara) but the FCV was closed again to change the lip pipe for a more appropriate diameter to use James' lip pressure method. Thus, a third attempt was carried out (WHP reached 43.8 barg or 44.6 bara) and the well flowed continuously at a WHP of 3.1 barg, producing steam and brine until the FCV was closed after 2 weeks of testing.

2.2 Well X-1

PTS survey run under injection condition had shown that a downflow was occurring in well X-1 between the two identified feed zones: the first feed zone at 1033 masl acts as an inflow (flow from the reservoir into the wellbore) with a productivity index of about 91 kg/s.bar, exiting the wellbore at the second feed zone located at 590 masl, whose injectivity index is about 19 kg/s.bar. This strong downflow (estimated to be around 40 kg/s under static condition) thus required particular care in the execution of the discharge initiation.

Like for well X-2, the choice of the stimulation method for the discharge of well X-1 was based upon its PT profile at the time of the test. This profile showed that the pressure at the first feed zone located at 1033 masl was 27 bara only and the ratio A_f/A_c was clearly less than 0.7 (Figure 6), suggesting that the well would most likely not discharge with air compression technique.

As already stated for well X-2 case, the comparison of log down and log up runs of X-1 indicated that the temperature profile matching the saturation curve between 1425 and 1300 masl was not due to a pressure drop in the well during the logging, but truly reflected the static condition of the well.

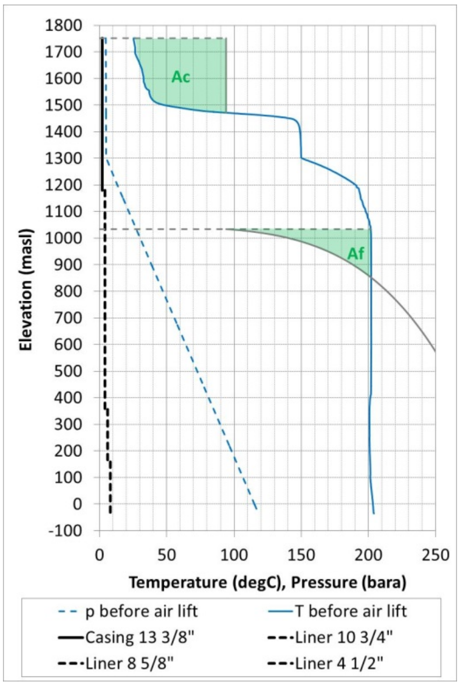

Figure 6: Well X-1 PT profile before discharge initiation

2.2.1 Air lift

Given the very low probability to successfully discharge well X-1 by using air compression, the technique that was chosen was again air lift, still using the rig and drill string (made of 5 in., $3^{1/2}$ in. and $2^{3/8}$ in. joints). The depth of injection was set at 800 masl (ie. below the first feed zone acting as an inflow) so that the height of lifted fluid was equal to the height of nearly-vacuum condition in the well (see paragraph 2.1.1).

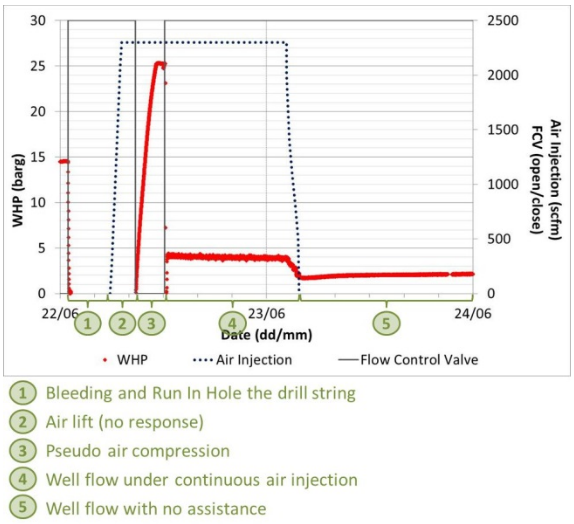

Figure 7: Well X-1 discharge attempt with air lift

As presented in Figure 7, once the well had been bled off and the drill string run in hole to 800 masl depth (1), air was injected gradually up to 2300 scfm. After 1.5 hours of continuous injection, no response was observed at the wellhead (null WHP and no fluid produced at the separator) (2) and decision was taken to close the FCV to check that some air was coming back to the surface. By doing so, the WHP immediately increased and reached 25.3 barg (26.1

bara) after 2.5 hours (3). This confirmed that some of the air that was being injected was counter-flowing the downflow and reaching the surface. Therefore, by pressurizing the wellhead, this operation was finally equivalent to an air compression combined with an air lift since the air was being injected at the bottom hole through the drill string. The stabilization of the WHP at 26.1 bara maximum under continuous air injection signified that the water level was compressed down to the vicinity of the first feed zone (around 1030 masl), as expected. After 1 hour of WHP stabilization, the FCV was opened, 10 minutes passed with no response at surface (null WHP and no fluid produced at the separator) and the well finally discharged with a WHP of 4.2 barg under continuous air injection (4). The air injection was then gradually reduced down to 0, and the well kept on flowing at 2.2 barg WHP and produced steam and brine (5) until the FCV was closed after 27 hours of non-assisted flow.

Two days after the well had been closed, a new PT profile was recorded in well X-1 under shut-in condition (Figure 8). As expected, the strong downflow initiated at the first feed zone prevented to see any temperature improvement in the reservoir section, but it showed that the top part of the casing was already cooling down, back to the equilibrated conditions observed before the discharge, the first 250 m of casing being already under the saturation conditions.

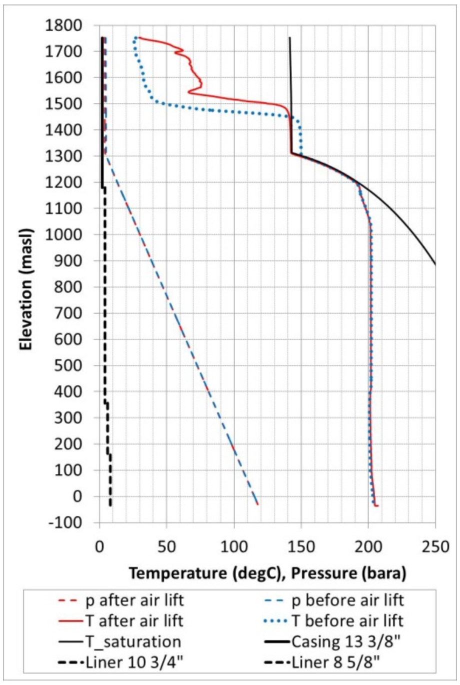

Figure 8: Well X-1 PT profile 2 days after discharge initiation

2.2.2 Air compression

Despite the fact that this new PT profile showed that well X-1 still had very little chance to discharge with air compression, a new attempt was performed using this technique after 25 days of alternative shut-in and injection conditions (to handle the brine produced at well X-2). The choice of this method was regarded as a quick and cheap try to evaluate the possible flow performances of the well without any drill string left in the well this time.

In order to heat up the top part of the casing (like what is commonly done with a portable boiler) and thus maximize the chance of success of this new discharge initiation, 2-phase hot fluid from well X-2 (which was flowing at that time) was directly re-injected into well X-1 during 15.5 hours just before the air compression was performed.

Figure 9 shows the two series of attempts that were carried out over 24 hours, the air being injected at the wellhead through the wing valves again. The WHP under air compression was around 24.5 barg (25.3 bara) each time, meaning that the liquid level was compressed down to the vicinity of the first feed zone again (around 1030 masl).

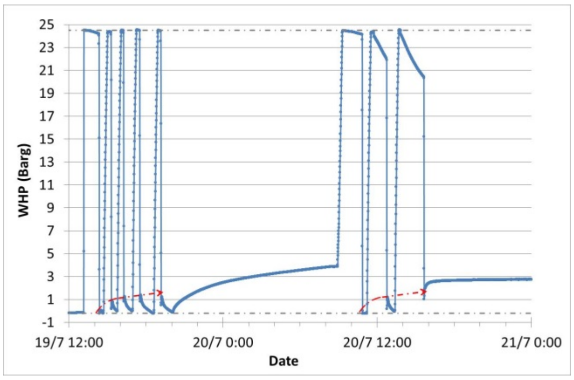

Figure 9: Well X-1 discharge attempt with air compression

The first 5 attempts failed to discharge the well as the WHP remained null and no fluid was produced at the separator. However, some improvements were observed since the WHP after opening the FCV increased after each of these attempts, from 0.1 to 1.4 barg (as indicated by the red arrow on the left). At the same time, the casing head temperature was recorded manually and also increased after each of these attempts, from 84 to 94 degC (the temperature being already relatively high due to the 2-phase hot fluid injection form well X-2).

After 13 hours of shut-in, 3 additional attempts were performed. This time, the attempts were repeated more closely. In addition, the well remained pressurized for a longer time (1.5 to 2 hours) before opening the FCV, allowing the casing head temperature to increase rapidly (134 degC on the last attempt), and leading to a higher WHP after opening the FCV. Finally, for the last attempt, the lip pipe had been changed to be replaced by a bigger diameter one (from 6 to 10 in.). As a consequence, on the last attempt, the well flowed continuously at 2.9 barg (3.7 bara) WHP and produced steam and brine until the FCV was closed after 31 hours of flow.

3. LESSONS LEARNED AND METHODOLOGY

In addition to cost, operation and safety concerns, the choice of the method to be used for the discharge of a high enthalpy geothermal well always requires a good assessment of the reservoir properties. A recent (like well X-2) or stabilized (like well X-1) PT profile is mandatory to observe the temperature profile all along the well and to identify the depth of the water level in the wellbore. A precise characterization of the feed zones (depth and permeability) is also needed, especially if a downflow is occurring in the wellbore.

Then, depending on the reservoir properties, the following criteria and procedures shall help to choose the most appropriate technique and to guarantee safe and successful operations.

3.1 Air lift

3.1.1 Operation and safety

Air lift technique requires the use of coiled tubing or rig drill pipes to inject air at depth. Both involve the use of BOP whose temperature limitation is commonly around 120 degC, which can limit the duration of the test if there are no means to cool down the internal part of the BOP.

Globally, the use of coiled tubing is much more convenient since it allows a quick and easy adjustment of the depth of injection as well as a safe Pull Out Of Hole (POOH) operation which does not disturb the continuity of the well discharge. However, the injection rate is commonly limited to 1500 scfm (for a 2 in. coiled tubing), which can be too low to lift high water column or if some of the injected air risks to be trapped in fractures when bubbling up (especially in high inclination wells).

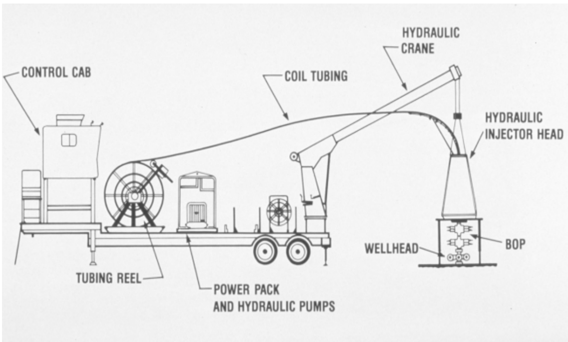

Figure 10: Typical set up of a coiled tubing unit

The use of rig drill string is not considered as a common practice, but it can be interesting in some cases. The injection rate can usually reach 2300 scfm by connecting the air compressor to the two 3 in. wing valves on the wellhead. However, there are some risks of corroding the drill pipes (not observed during the operations described in this paper) and it implies the mobilization of the whole rig and of most of the associated equipment and services, which can be incompatible with the production and injection surface lay-out. Unlike coiled tubing, the adjustment of the depth of injection is commonly not allowed (as stripping the drill pipes through the BOP is a hazardous and time-consuming operation) and it is usually mandatory to interrupt the well discharge to POOH the drill pipes. In the case of well X-2, adjustment of the drill pipes depth was allowed since the WHP dropped to zero once the FCV on the production line had been closed. It can also be noted from Figure 11 that the choke and kill lines were inserted between the top and bottom pipe rams to allow the injection of cold fluid within the BOP on top of the bottom pipe ram (which was closed during injection and flowing) and thus to successfully maintain the BOP temperature below 120 degC (70 degC maximum was recorded at the BOP while the temperature in the production line was up to 134 degC).

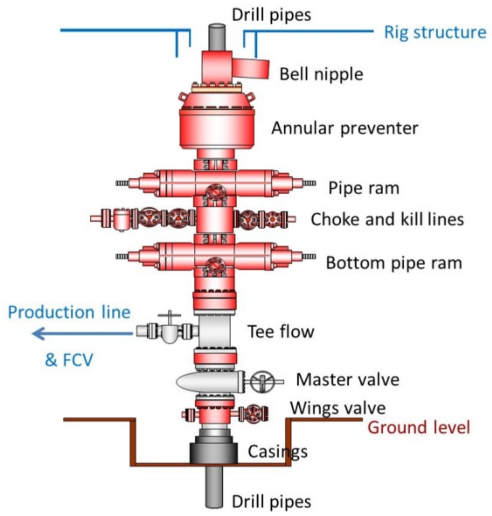

Figure 11: Set up of the BOP for air lift operation on well X-2

When low pressure and low temperature are expected (below 500 psi and 100 degC), and if a single size of drill pipes can be used for the operation (depending on the well design), a rotating head can be used for the stripping operation in a much more appropriated manner: both the pipes and their joints can slip through the rubber equipment, allowing safe and quick movement of the drill pipes while the well is flowing. With the BOP configuration presented in Figure 12, the annular preventer has to be removed to accommodate the space below the rig structure, but this is still acceptable since the top and bottom pipe rams remain as safety barriers. Cold fluid injection at low rate can again be realized through the choke and kill lines in order to cool down the BOP equipment during flowing. In addition, a second master valve can be added on top of the tee flow to allow to remove the BOP and the whole rig structure without interrupting the well discharge once it has been initiated.

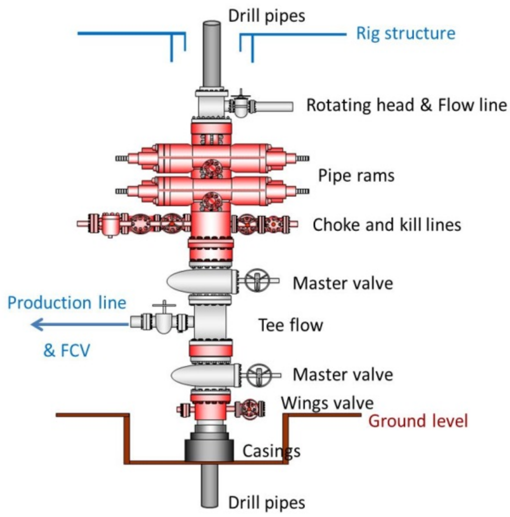

Figure 12: Alternative set up of the BOP for air lift operation

Finally, whether rig drill string or coiled tubing is used, one shall keep in mind that the total area (cross section) available for production flow is reduced by the insertion of the air injection line within the well, which will imply higher pressure drops. Therefore, the well performance observed when using this technique does not reflect the true and optimal ability of the well. In addition to the fact that air lift efficiency was reduced by some trapping of the injected air in the formation (as explained in 3.1.3), this could explain why this technique did not manage to discharge well X-2 while air compression successfully did 2 days later.

3.1.2 Cost

Generally, the use of coiled tubing requires long-term planning since the available units are usually limited (most of them being assigned to oil and gas projects). The cost for a typical 4 day job can range from 150,000 to 500,000 USD, depending mostly on the mobilization cost.

The use of rig is usually limited to special cases when no coiled tubing unit is available or when the rig is standing-by for example. The cost for a typical 4 day job can be as high as 500,000 USD, and is mostly impacted by the rental of the rig and the associated equipment and services.

3.1.3 Methodology

Regarding the air injection rate, this should be adjusted based on the observations made on site when increasing or decreasing the rate gradually (300 scfm every 20 minutes for example) in order to gradually heat-up the casing and avoid thermal shock, and also in order to minimize the pressure drops in the wellbore (an optimum theoretically exists) and maximize the flowing WHP. However in practice, this optimum may be difficult to be found in real operational conditions where time is limited, and the maximum air injection rate may be finally used.

The time at which air injection has to be reduced and stopped to see if the well can flow without assistance shall be when the flowing WHP is stabilized and when clear brine is continuously produced at the Atmospheric Flash Tank (AFT).

Finally, the main parameter to set in air lift operations is the depth of injection. As a common practice, the first attempt should be carried out at a depth so that the height of lifted fluid (ie. from the depth of injection to the water level in the well) is equal to the height of nearly-vacuum condition in the well (ie. from the water level to the wellhead), in order for the reservoir fluids to reach the surface. Except if the reservoir is underpressured, injecting below this depth could be less efficient if there is a risk for the air to be trapped into highly permeable zones such as fractures (especially in high inclination wells) and since the pressure drops will be higher. This was confirmed with the air lift on well X-2, where the injection at the second and deepest depth led to a lower (by 0.4 bar) flowing WHP under continuous air injection (Figure 3).

In addition, in the case of a well with a strong downflow in the wellbore like well X-1, one shall keep in mind that a considerable amount of air can remain trapped downhole, preventing any fluid to be lifted up to the surface (Figure 7). Therefore, air lift is not advised if the optimized depth of injection is located below a downflow. However, if despite of everything this situation is encountered, it is still possible to try to perform a pseudo air compression like for well X-1 by closing the FCV and pressurizing the wellhead with downhole air injection (Figure 7).

Generally speaking, this is a procedure that can be attempted if the air lift has not succeeded in making the well flow continuously.

3.2 Air compression

3.2.1 Operation and safety

Air compression technique is much more simple and safer since it implies only the use of an air compressor and the related services. This compressor is connected to the two 3 in. wing valves of the wellhead, while the production line links the master valve to the separator. Furthermore, this method allows dismantling of the air compression equipment without interrupting the well discharge.

However, by pressurizing the top part of the well with cold air, this technique may cause thermal shock on the production casing. Mitigation practices such as preceding 2-phase hot fluid injection or non-immediate opening of the FCV (discussed below) are recommended to avoid such a risk (and increase the probability of success of the operation).

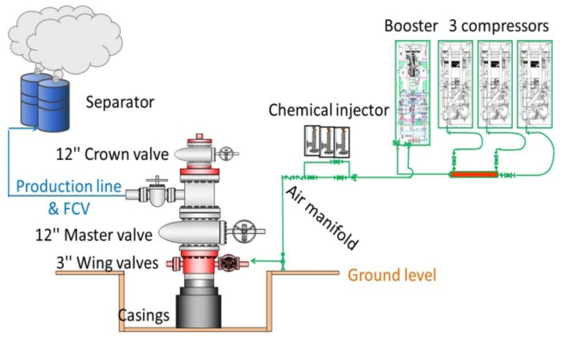

Figure 13: Typical set up of an air compressor unit

3.2.2 Cost

The cost of this technique is usually one order of magnitude less than the cost for air lift, a typical 4 day job averaging 50,000 USD. In addition, the equipment and services are usually contracted for drilling activity already, making this kind of technique easily and quickly available.

3.2.3 Methodology

The applicability of this technique is properly assessed by Sarmiento's methodology (1993) as a first approach: the temperature profile needs to be known to calculate the areas A_c and A_f, and the first feed zone location needs to be correctly estimated to predict the maximum WHP during compression and by how many meters the liquid level in the wellbore will be compressed.

However, the different attempts to discharge wells X-1 and X-2 have shown the importance of the temperature of the top part of the casing. Indeed, after having heated up the top part of the casing during the unsuccessful attempt to discharge well X-2 by air lift (Figure 3), the attempt using air compression immediately succeeded (Figure 5). Even more surprisingly, the pseudo air compression attempt of well X-1 (Figure 7) also succeeded in discharging the well despite the fact that the ratio A_f/A_c was clearly less than 0.7 initially. As the air was first continuously injected downhole and heated up when returning back to the surface, the top part of the casing got heated up as well. Then, after the reopening of the FCV, the fluids in this upper part of the well started to flash and finally initiated the discharge after 10 minutes.

Therefore, even if the ratio A_f/A_c was clearly less than 0.7 in well X-1 before the second attempt of discharge by standard air compression (Figure 9), this method was proposed and implemented successfully by trying to heat up the top part of the casing through:

- 2-phase hot fluid injection prior to the air compression. This operation has not been clearly proven to be efficient on this last attempt, but the duration of the injection may have been too short (15.5 hours). Further tests on well X-1 will allow to conclude on this point.
- Various and closely repeated pressurizations of the wellhead.
- Longer duration under pressurized condition before opening the FCV.

In addition to this, when facing some problems to initiate the discharge of a well by air compression, one shall check that the lip pipe diameter is not too small and does not throttle the well too much. In the case of well X-1, 10 in. diameter lip pipe was found to be a minimum to allow the well to flow (this was confirmed at the end of the test by attempting to throttle the well by reducing the FCV opening).

Consequently, even when the ratio A_f/A_c is clearly less than 0.7, the cheap and easy air compression technique may successfully discharge a well (even more efficiently than the air lift technique) if a certain procedure aiming at heating up the top part of the casing is followed, as shown by wells X-1 and X-2 case study: this will indeed allow to reduce the heat loss of the next air compression attempt and thus increase the probability of success of the discharge. Furthermore, this technique is not impacted by the presence of a downflow and is therefore much more reliable than air lift in this particular case.

Figure 14: Well X-1 flowing at the separator after air compression

4. CONCLUSION

The case study of wells X-1 and X-2 in Rantau Dedap field gives a very good opportunity to assess the effectiveness of air lift, air compression (and even 2-phase hot fluid injection) techniques in the case of a well facing or not a downflow in the wellbore.

Air lift using coiled tubing or rig drill string was found as an expensive (about 500,000 USD), non-flexible (especially when using rig) and complicated method (from an operational point of view). This method did not lead directly to the successful discharge of well X-1, mostly because the downflow occurring in this well prevented the air to lift the water column in the wellbore. In the case of X-2, this method did not manage by itself to discharge the well neither, because the reduced area available for flow in the wellbore initiated high pressure drops and because the efficiency of the lift was probably degraded by some losses in permeable zones such as fractures. However, the downhole injection of air helped here to heat up the top part of the casing, which clearly increases the chance of success of a subsequent pseudo air compression (like for well X-1) by closing the FCV and pressurizing the wellhead with downhole air injection.

Conversely, air compression is known to be a cheap (about 50,000 USD) and convenient method. Regarding its applicability, Sarmiento's methodology provides empirical guidance to assess the probability of success of such a technique. However, in the case described as probable failure (when the ratio A_f/A_c is less than 0.7), this technique may successfully discharge a well (even more efficiently than the air lift technique) if the following procedure aiming at heating up the top part of the casing is applied:

- 2-phase hot fluid injection prior to the air compression,
- Various and closely repeated pressurizations of the wellhead,
- Longer duration under pressurized condition before opening the FCV.

Furthermore, this technique is not impacted by the presence of a downflow (as long as it is a hot one like in the case of well X-1) and is therefore much more reliable than air lift in this particular case.

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