ISSN: 2639-7536

Research Article

Petroleum and Chemical Industry International

Controlling Condensate Gas Well by Lubricating and Bleed-Off Method, Case Study

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Submitted: 13 Oct 2021; **Accepted:** 18 Oct 2021; **Published:** 11 Nov 2021

Citation: *Koorosh Tookallo, Abas Sarkari, Reza Jamali, Hamed Gheibparvar (2021). Controlling Condensate Gas Well by Lubricating and Bleed-Off Method, Case Study. Petro Chem Indus Intern, 4(3), 56-62.*

Abstract
During flow a condensate gas well, downstream pressure dropped many times. The reason was partially plug which was occurred in choke manifold adjustable path due to producing abnormal cutting, junk and debris. Produced debris led to other problems such as malfunctioning in the Christmas tree and subsurface safety valve. The goal of this article is to present the procedure of lubricating and bleed-off method to control a gas well during production when there are malfunctioning in x-mas tree valves and subsurface safety valve. In this paper, other operations such as the Christmas tree substitution with a new one, installing and retrieving blanking plug, and mending subsurface safety valve malfunction are explained stepwise.

Key words: Well control, Condensate gas well, lubricating and bleed-off method, Christmas tree malfunctioning, Subsurface safety valve malfunctioning

Introduction

Oil industry in the upstream section has lots of different operations and engineers who work in this field face different issues. After drilling and completion a condensate gas well, during flow the well on 72/64" and 76/64" adjustable choke (Adj. Choke), downstream pressure dropped many times. The well flowed through the surface well testing facility to find the problem. A partial plug occurred in the choke manifold adjustable path when the well was flowing through the surface testing facility. So, the adjustable choke was opened to search and rectify the problem. It was observed that abnormal cuttings contain iron pieces and junk that reached the surface plugged the adjustable choke path. The well flowed for four days but, the debris production didn't stop, and the well didn't clean up. The next plan was running a magnet in the hole by coil tubing unit to clean up the wellbore. But, produced debris had led to both leakages of the hydraulic master valve (HMV) and swab valve of the Christmas tree (x-mas tree) and had led to the failure of the subsurface safety valve (SSSV) too.

Replacement of x-mas Tree with new one

Due to unsuccessful actions to repair the x-mas tree valves, such as using special grease, opening/closing the valves, and complete failure of swab valve, it inferred there is a severe problem with the sealing area or stem packing, which possibly caused by the debris. So, it needed to replace a new x-mas tree with the old one.

SSSV Flapper/Flapper seat sealing malfunctioning

Different assumptions could be the reason for the SSSV malfunctioning. After a comprehensive investigation, flapper/flapper seat sealing malfunctioning was recognized as the main issue.

Following points could result in such a problem

Case1; Produced debris during well production or SSSV operation while production (opening and closing) could be deposited in the sealing area of the flapper/flapper seat, which prevents the flapper to be fully closed, and leading to severe leakage.

Case2; While closing the SSSV, it is possible that debris between flapper/flapper seat could severely damage the sealing area due to the force applied by fluid pressure against flapper.

Regarding the history of the well, debris production, and leakage on SSSV/HMV, several meetings were held between service companies and the client.

According to the last technical meeting between the client and engineering department, the safety of the well specified as a primary priority, and then, decided to control the well by lubricate and bleed-off method. After that, the x-mas Tree will replace with a new one and then work on SSSV.

Lubricate and bleed-off method

When the circulation is impossible to conduct, lubricate and bleed-off method is the way to remove the gas. The basic theory is just the reverse process of the volumetric well control method. By pumping drilling fluid into the wellbore, surface pressure will be replaced with hydrostatic pressure. Drilling mud and gas will swap the places and after that, surface pressure will be bled off.

In the first step, the hydrostatic pressure of the required mud volume (lube increment) that pumps into the well must determine. In second step, slowly pump a desired volume into the well. The amount of volume depends on the well conditions and it may change during the process. Increasing surface pressure can be estimated by utilizing Boyle's Law. For every one barrel (bbl) of mud pumped into the well, the gas size is reduced by one bbl.

Boyle's law states that within a closed system at a constant temperature, the absolute pressure and the volume of a gas are related inversely. Figure 1 demonstrates changes in volume and pressure as per Boyle's Law.

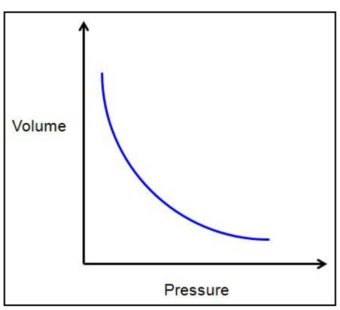

Figure 1: Changes in volume and pressure according to Boyle's Law

The mathematical relationship of Boyle's Law is; $P1 \times V1 = P2 \times V2$

Where;

P1 = pressure of gas at the first condition

V1 = volume of gas at the first condition

P2 = pressure of gas at the second condition

V2 = volume of gas at the second condition

During lubricating, surface casing pressure will be definitely increase. The amount of pressure increase will depend on the volume of gas being compressed. Small pressure increase indicates large volume of gas. According to the increase in hydrostatic pressure during lubrication, maximum allowable surface casing pressure (MASCP) will reduce.

The column of fluid creates the Hydrostatic pressure. Height of fluid and density of fluid are two factors that affect hydrostatic pressure. Pressure at the bottom hole equals to hydrostatic pressure plus surface pressure.

Pressure (bottom hole) = Hydrostatic Pressure + Surface Pressure

The gas volume decreases every time that gas is bled off. In order to prevent breaking out the wellbore you must reach the point to stop lubricating operation.

In third step, you should wait for a while to allow gas and mud swapping out. Drilling mud properties as mud weight and rheology affect this step. Step four is bleeding gas from the surface until the amount of pressure is equal to hydrostatic pressure of mud pumped in hole. If you know that you lubricate in 60 psi, only 60 psi of gas must be bled off. It is very important to bleed only gas. During this process if you see mud on surface, you must stop and allow gas to swap out. For instant, you plan to bleed a total of 60 psi but you observe mud coming out when you bleed only 30 psi, you stop the bleeding process and shut the well in. Then, you continue bleeding the remaining 30 psi later. If the mud is accidentally allowed to come out during this bleeding process, the bottom hole pressure will reduce and resulting in more influx coming into the wellbore. Repeat step 2 – 4 until you get the gas out of the well or the desired surface casing pressure is reached. [1,2]

Well information

The desired well in this article is a deviated J-shape well with a maximum inclination of 66.13^{o} degree which produces condensate gas with about 5000 PPM H2S content. Information about the well comes in Table 1.

Table 1: Well information

Completion type	Mono-bore
Pressure Gradient of gas in Tubing	0.117 psi/ft.
Fracture Gradient	0.835 psi/ft.

Last Shut-in well-head pressure (WHP) recorded for designing kill mud weight. Maximum allowable surface pressure Calculated for killing procedure. Initial maximum allowable surface pressure calculated. Initial MASP calculated by considering surface equipment working pressure and safety. Final maximum allowable surface pressure calculated. Bottom- hole reservoir pressure calculated. Minimum surface pressure calculated to prevent flow the well. The killing fluid mixed and ensured that sufficient surface tank volume is available to displace the complete volume of the hole with killing fluid.

Cement unit (CMT unit) lined up to the kill valve and low torque valve, and then the entire surface lines of the equipment tested by CMT unit to 4500 psi. Close the Hydraulic Flowing Valve, Pump from CMT Unit Up to (WHP + 400Psi) for Equalize Pressure CMT Unit with Shut in Well head Pressure (WHP) and prepare for open X-mas tree kill valve.

For more safety, before starting each stage, Equalize CMT unit Pressure with Shut-in Well Pressure. After stop pumping and lubricating time, close kill valve and Low Torque valve to Prevent Influx the gas into CMT unit. Start killing The well by Pumping calcium chloride (CaCl2), Brine 11.4 ppg, into the well through the kill valve from CMT unit, up to limited pressure ,Never more than reservoir fracturing pressure (Limited pressure must confirmed with all departments such as engineering and reservoir and operation Dep.) , then stop pumping , close Kill Valve & Low Torque valve and wait for lubricate gas and brine, record static WHP until keep constant(As per same situation : 2.5 hrs.). Open the well from production line and bleed off pressure till 200psi more than recorded last shut in WHP, (for next step calculate MASP and minimum allowable surface pressure based on level of kill mud and gas in the well) again close the Well, check Static WHP. Commence pumping into the well through the Kill valve, up to MASP, stop pumping and wait for Lubricating gas and brine, record Static WHP until keep constant. Open the well from production line and bleed off pressure till minimum allowable surface pressure. Repeat Step #3 by considering maximum and minimum allowable surface pressure in each step, till take kill mud in Return and hole will be stable.

We can reduce mud weight of kill mud during killing the well for prevent damage the reservoir (depended of WHP Behavior during job).

Notice

- Limited pressure must confirm by the reservoir department.
- Wait and observe if any gas remains at the bottom to come up and lubricate by pill.
- Keep calculates pressures during the operation, especially for hydrostatic pressure of kill mud on well (reservoir fracturing pressure).
- Be careful for leakage in surface equipment such as line up from CMT unit to X-mas and X-mas tree body.
- In addition to the above, based on a more safety policy, a 13-13.5 ppg heavy kill mud must be available all the time for emergency cases.
- Static Flow Check, If Hole Condition was stable, stop operation and observe hole from all side.
- After killing the well monitor the well for a while to be sure about any loss and gain, make decision to install Blanking Plug and replace the X-mas Tree with a new one. Retrieve BPV and Blanking Plug.

Killing Operation

Pre-safety job meeting held with all involved personnel. The X-mas tree valves situation, during pumping in the well and during the closing, come in Table 2.

Table 2: X-mas tree valve situation during pumping in the well and during close the well

X-mas tree valve situation	Swab Valve	Manual Wing Valve (MWV)	Hydraulic Wing Valve (HWV)	Kill Valve	Hydraulic master Valve (HMV)	Bottom Master Valve (MMV)
During pumping in the well	Close	Close	Close	Open	Open	Open
During releasing pressure of the well	Close	Open	Open	Close	open	open

Figure 2 shows the sketch of the safety valves.

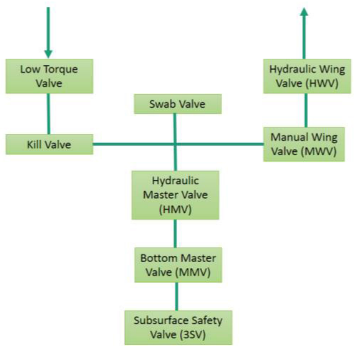

Figure 2: Sketch of the safety valves

7000 psi pressure was applied inside the control line to sure that SSSV is in the open position.

Step 1

The pressure behind the low torque valve was equalized to 3600 psi after that low torque valve and kill valve opened, and then 75 bbl brine (11.4 ppg) was pumped in the hole. During pumping brine, pressure gradually decreased from 3450 psi to 2750 psi. Then pumping stopped, and the low torque valve and kill valve closed until gas could lubricate with brine. Wellhead pressure stabled at 3400 psi.

Step 2

For the second time, pressure behind the low torque valve was equalized to 3600 psi after that low torque valve and kill valve opened, and this time 75 bbl brine (10.5 ppg) was pumped in the hole. During pumping brine, pressure gradually decreased from 3400 psi to 2700 psi. Then pumping stopped, and the low torque valve and kill valve closed until gas could lubricate with brine and achieve stable wellhead pressure about 3200 psi. After that, HWV and MWV opened to reduce gas pressure from 3200 psi to 2500 psi via platform production.

line to the flare stack. After a while pressure constant at 3000 psi. Figure 3 shows the flare stack.

Figure 3: Flare stack

Step 3

For the third time, pressure behind the low torque valve was equalized to 3200 psi after that low torque valve and kill valve opened, and this time 75 bbl brine (10.15 ppg) as the third batch was pumped in the hole. During pumping brine, pressure gradually increased from 3000 psi to 3100 psi. Then pumping stopped, and the low torque valve and kill valve closed until gas could lubricate with brine and achieve stable wellhead pressure about 2950 psi.

Step 4

pressure behind the low torque valve was equalized to 3200 psi after that low torque valve and kill valve opened, and this time 150 bbl brine (10.15 ppg) as the forth batch was pumped in the hole. During pumping brine, pressure gradually increased from 2950 psi to 3500 psi. Then pumping stopped, and the low torque valve and kill valve closed until gas could lubricate with brine and achieve stable wellhead pressure about 3400 psi. Wellhead pressure was bleed-off to 2700 psi via the production line, and after a while pressure constant at 2670 psi.

Step 5

System lined up to CMT unit, and 100 bbl. brine (10.5 ppg) pumped as the fifth batch into the well. Pressure increased from 2670 psi to 3200 psi. Wellhead pressure was bleed-off to 2490 psi via the production line. As shown in Table 3, this procedure continued until in step 21 that the well was killed and the wellhead pressure became constant at 0 psi.

Table 3: well reports, during the well control procedure

Step	Initial Wellhead pressure (psi)	Pumped volume of brine (bbl)	brine weight (ppg)	Brine volume in well (bbl)	Formation loss (bbl)	Final wellhead pressure after pumping(psi)	Final pressure (psi)
1	3600	75	11.4	75	-	3400	3400
2	3400	75	10.5	150	-	3200	3000
3	3000	75	10.15	225	-	3100	2950
4	2950	150	10.15	375	-	3400	2670
5	2670	100	10.5	475	-	3200	2490
6	2490	75	10.5	550	-	2900	2050
7	2050	75	10.5	625	-	2100	1000
8	1000	90	10.5	669	46	2050	500
9	500	70	10.5	669	70	1350	0
10	0	45	10.5	669	45	700	0
11	0	48	10.5	669	48	400	0
12	0	5	10.5	669	5	90	0
13	0	19	10	669	19	110	0
14	0	22.5	10	669	22.5	200	0
15	0	11.5	10	669	11.5	300	0
16	0	18.5	10	669	18.5	200	0
17	0	18.5	10	669	18.5	0	0

18	0	23	10	669	23	0	0
19	0	32	10	669	32	0	0
20	0	32	10	669	32	0	5
21	5	29	10	669	29	5	5

The gas test was performed three days six times, and the results show in Table 4. After step 19, the gas test was performed through the tree cap needle valve four times. After step 20, the gas test was performed through the tree cap needle valve two times.

Table 4: Results of gas test

Step	H2S ppm	LEL %
1	30	5
2	16	5
3	0	0
4	0	0
5	20	5
6	20	5

Set the blanking plug

After killing the well, the well monitored for a while to be sure about any loss and gain, then as explained below, a blanking plug was installed. The well was monitored, and after that, a back-pressure valve (BPV) was installed.

Blanking Plug Installation Procedure

The pre-job safety meeting was conducted with all personnel including rig crew, all Service Companies, and topside crew. The surface line was lined up from the Cement unit (CMT unit) to the kill valve and low torque valve. Then all surface line equipment was tested by the CMT unit. Breathing apparatus (BA) and H2S safety equipment prepared for all personnel involved in this job. Hydraulic Master Valve, Swab Valve, and SSSV were closed. After that, the production wing valve and production line were opened and got ready for the job. The pressure gauge was opened to check H2S. There was no H2S in the line so the tree-cap was opened. An auxiliary valve was installed on the swab valve with consideration of the safety points. The blow-out preventer (BOP) of the slick line Installed, and the hydraulic hoses connected to the rams. The BHA prepared for dummy run. We ensured that pressure below the swab valve is zero, and then the swab valve and auxiliary valve opened. Pressure equalized against the hydraulic master valve, and then the hydraulic master valve opened slowly. In the next step, the subsurface safety valve (SSSV) opened, and dummy BHA ran in the hole. BHA pulled out of the hole with the proper speed limit. BHA should be passed through the wellhead slowly and carefully. BHA prepared and Connected to the string. We ensured that the blanking plug was in good condition. We ensured that pressure below the swab valve is zero, and then the swab valve and auxiliary valve opened. Pressure equalized against the hydraulic master valve, and then the hydraulic master valve opened slowly. 10bbl fluid pumped into the well to make sure that the SSSV polished bore is clean. Wellhead should be passed through slowly and carefully. The running tool and lock assembly is lowered onto the well bore until the lock stops at the no-go. Gentle downward jarring may be necessary to ensure the seals fully enter the seal bore. Downward jarring shears the upper shear screws and expands the locking dogs into the nipple profile. 300lb tension (over pull) applied to slick line wire for 1 minute in order to check that the Blanking Plug has been set successfully. Upward jar applied to shear the pin, and string pulled out of the hole. When BHA arrived at the surface and confirmed that BHA assembly located above the master valve, HMV Closed, trapped pressure bleed off through choke manifold if any. The swab valve and auxiliary valve Closed. The running tool indicator checked to make sure that the plug was installed successfully. Sink Bar (SB) pulling tools with equalizing prong connected to the string. Start RIH with BHA. Slack off the weight, start jarring down gently. Apply intense hand jar to shear the SB P/T pin. Commence POOH with proper speed limit. When BHA arrived at the surface, the lower joint lubrication opened, and BHA disconnected. Open HMV and start pump in through kill line, pressurize the tubing, and hold for 5 min. in order to test the blanking plug functionality. If the test was OK, Bleed off pressure through choke manifold. Close HMV. The well monitored and BPV installed.

The well condition checked and x-mas tree changed. Table 5 shows the sketch of blanking plug installation BHA.

Table 5: Blanking Plug installation BHA Sketch

Item	BHA Description
1	Pear Drop Rope Socket
2	Swivel
3	Sink Bar
4	Sink Bar
5	Sink Bar
6	Hydraulic Jar
7	Mechanical Jar
8	Adjustable spring Centralizer
9	SB Pulling Tool

Replace the X-mas Tree with new one

After installing blanking plug and back pressure valve (BPV), the X-mas tree replaced with a new one. BPV retrieved and the next plan was retrieving the blanking plug.

Blanking Plug Retrieval Procedure

The production wing valve, Hydraulic Master Valve and Swab Valve were closed. The BHA prepared for retrieving equalizing prong. We ensured that pressure below the swab valve was zero, and then the swab valve opened. Pressure equalized against the hydraulic master valve, and then the hydraulic master valve opened slowly. The BHA ran in the hole to retrieve equalizing prong. The prong fishing neck latched with SB P/T, apply several jars up. (Make sure that the pressure against the plug is equalized). BHA pulled out of the hole with the proper speed limit. The lower joint lubricator opened and SB P/T and equalizing prong disconnected. M pulling tool Connected to the tools string and lubricator connected. The pressure equalized against the hydraulic master valve. The hydraulic master valve opened slowly. The BHA ran in the hole to retrieve the blanking plug. The plug fishing neck latched with M pulling tool (P/T) and applied several jars up and BHA was pulled out of the hole. When BHA arrived at surface and confirmed that BHA assembly was located above master valve, HMV closed, and trapped pressure bled off through the choke manifold. Table 6 shows blanking plug retrieval BHA sketch.

Table 6: Blanking Plug Retrieval BHA Sketch

Item	BHA Description
1	Pear Drop Rope Socket
2	Swivel
3	Sink Bar
4	Sink Bar
5	Sink Bar
6	Hydraulic Jar
7	Mechanical Jar
9	M Pulling Tool

Work On TRSV

BPV and Blanking Plug retrieved and the next plan was mending SSSV malfunctioning.

Mending SSSV malfunctioning

The SSSV flapper Closed. Coil tubing unit (CTU) Ran in the hole (RIH). With the usage of a washing nozzle, fluid (preferably high viscosity fluid) was pumped with a maximum rate at flapper depth. Pumping continued several times. While pumping, the flapper opened and closed several times. (Note: be careful that the CTU nozzle must be at list 2 meters above the flapper). Finally, after several times pumping, deposition in the sealing area of the flapper/flapper seat removed, and the flapper fully closed. Then CTU pulled out of the hole, and SSSV malfunctioning repaired.

Acknowledgment

I want to acknowledge the engineering department of Petro Gohar Farasahel Kish Company for helping us through preparing this practical paper.

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