New method developed to treat individual layers in cemented cased-hole completions

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A NEW METHOD of completing multiple-layer formations has been successfully tested in the United States and Canada. This new method places sliding sleeve valves in the casing string and completes the well with normal cementing operations. The sliding sleeve valves are opened one at a time to fracture layers independently without perforating.

Completions using these casing valves are called treat and produce (TAP) completions and have a unique design feature in the valves that allows a theoretically unlimited number of valves to be placed in a single well without incremental reductions to the internal diameter (ID).

This near full bore feature allows normal cementing operations to be performed with a special cement wiper plug. A control line is connected between sequential valves. When the bottom valve opens, the control line becomes pressurized and transfers the bore pressure to a piston in the valve immediately above. This piston squeezes a C-ring and makes the ID smaller. At the end of the fracture treatment to the lower valve, a dart is dropped during the flushing operation. This dart lands on the squeezed C-ring and seals the bore inside the sliding sleeve. Pressure is then increased until the next valve is pumped open. When this valve opens, the next control line is pressurized, squeezing the next C-ring.

The main feasibility issue with this cemented sliding sleeve concept was fracture initiation pressure through the cement and into the formation without perforated holes. Significant laboratory testing was conducted that predicted fracture initiation pressure to be similar to that encountered in open hole or even lower. Fracture initiation pressures were closely monitored during several field installations and confirmed that perforations were not needed to initiate fractures in the formations.

This article describes TAP completions, how the TAP valves work and how the valves performed. Information is given on a TAP completion with six layers and an overview of all installations to date.

BACKGROUND

The US and Canada tight gas market is deploying new methods to efficiently stimulate multiple-layer reservoirs, but the most common method remains the same. Most wells are completed with cemented casing. To stimulate the reservoir, a plug is set, one or more layers are perforated, and then the layer(s) are stimulated as a stage. This practice is repeated multiple times until all the layers are stimulated. Most wells are flowed within 24 hours to remove the treating fluids from the reservoir.

Operators seek to balance the quality and cost of the stimulations versus potential well production. One of the most important parameters affecting production is the number of layers fractured during a single stage. Stimulating multiple layers in a single stage is not ideal because layers with lower fracture gradients or formation pressure may take more of the treatment than planned, leaving the higher-pressure layers only partially treated. This is becoming more of an issue as development wells are being drilled in more dense spacing, increasing the chances of treating some depleted layers.

The TAP completion system has been developed to allow the efficient treatment of individual layers in cemented case-hole completions. TAP completions use special casing valves that isolate individual layers one at a time without any interventions. The TAP valves are near full bore and do not require incremental reductions of ID and thus allow normal cementing operations.

Figure 1 (above) shows that in a TAP valve cemented in an open hole with pressure on the ID, the cement in front of the ports has high stress. The high stress will crack the cement in front of the ports. This crack is modeled as a slot in Figure 2 (below). Applying pressure in the cement crack will cause the cement to separate.

Figure 2: Figure 3: The main TAP valve has a C-ring that reduces in size when squeezed by a piston. The C-ring originally has the same size ID as the valve, but when reduced in size, the C-ring becomes a seat on which the next ball or dart can seal. The illustration above shows the cross section of the main TAP valve and the C-ring in the run-in-hole position.
The TAP valves also have unique helical ports that align to any preferential fracture plane, regardless of the orientation of the valve in the casing string. These ports ensure a single bi-wing fracture plane is initiated from the wellbore and the fracture initiation pressure is kept to a minimum.

Prior to deploying TAP completions, a study was performed on how TAP completions would affect fracture initiation pressure. This information was presented in SPE 100572, "A Study of Fracture Initiation Pressures in Cemented Cased Hole Wells Without Perforations."

The best understanding on fracture initiation with TAP valves can be demonstrated by finite element analysis using simple 2D models as shown in Figures 1 and 2.

Figure 1 shows a three-ported TAP valve cemented in an open hole with pressure in the ID. Not surprisingly, the cement in front of the ports has high stress. This high stress will crack the cement in front of the ports. This crack is modeled as a slot in Figure 2.

Applying pressure in the cement crack will cause the cement to separate. If the cement is bonded to the formation, the stress level in the formation in front of the cracks will be similar to the stress levels in the cement. If there is no cement bonding to the formation, it is assumed that a micro-annulus will occur and fracture initiation will occur anywhere along the circumference and at open hole fracture initiation pressures.

In a real well, some friction between cement and formation is likely, but not a perfect bond. Therefore, the conclusion is that the fracture initiation pressures with TAP valves are expected to be comparable to open-hole fracture initiation pressure or lower.

THE MAIN TAP VALVE

The main TAP valve is a sliding sleeve valve with a few unique features that enable it to selectively open one valve at a time and isolate previously treated layers. There is a C-ring in the main TAP valve, which, when squeezed by a piston, reduces in size.

The C-ring originally has the same size ID as the valve, but when reduced in size, the C-ring becomes a seat on which the next ball or dart can seal. Figure 3 shows the cross section of the main TAP valve and the C-ring in the run-in-hole position.

The piston that squeezes the C-ring (the magenta colored component in Figure 3) is controlled by the pressure in a control line connected to the TAP valve below it. When the lower TAP valve is opened, the port to the control line is opened to the ID fluid.

The control line, which was at atmospheric pressure, now has bore pressure. The upper TAP valve receives the bore pressure via the control line and ports it to the C-ring piston. The C-ring piston has two atmospheric chambers. When the bore pressure floods one of these atmospheric chambers, the C-ring piston moves and squeezes the C-ring.

Figure 4 shows the TAP valve with a restricted ID and is able to catch the next ball or dart pumped down. When the dart lands on the C-ring seat, it creates a seal and pump pressure pushes the sleeve open.
THE TAP STARTER VALVE
The lowest TAP valve is designed to catch the first dart pumped into the well. This lowest valve is called the TAP starter valve and is a simpler valve with only a fixed machined restriction in the sliding sleeve. The starter valve does have a control line at atmospheric pressure, which is connected to the TAP valve above it. When the starter valve is opened, the next TAP valve C-ring is squeezed. Only one starter valve is needed per well, and it is the lowest valve.

THE REPEATER VALVE
The TAP repeater valve was developed for thick layers that require more than one point of entrance into the formation for stimulation or production reasons. This repeater valve does not have a restricted ID or a C-ring. It simply opens when the control line from the TAP valve below has bore pressure.

The repeater valve has a control line ported to the next TAP valve above it. When the repeater valve opens, this upper control line is pressurized by bore fluid. The next valve can be a TAP valve or another TAP repeater valve.

INSTALLATION
The following example of a TAP completion installation was for a client with a 10,000 ft, 8 ½-in. open-hole vertical well with six layers to be treated. The original plan was to perforate and fracture treat two layers per stage, three stages and with a 24-hour flow-back period between each stage. Four days were estimated from fracture treatment of the first stage to the last stage. The frac fleet was to leave between stages, requiring three well site setups.

A 4 ½-in. TAP completion with a tapered casing string was run instead. The 4 ½-in. TAP valves are 6 ¾-in. OD and can be run in a 7 ¾-in. open-hole or larger. The 4 ½-in. casing was run from the bottom of the hole to 8,300 ft, which is just above the top TAP valve. 5 ½-in. casing was then run to the surface. Five valves were installed in the well, one TAP starter valve and four TAP valves. The lowest layer was perforated. All TAP valves had handling pups pre-torqued onto the valves for easy handling by the casing crew.

Depth control was a very important step when installing multiple TAP valves, as each of the five valves needed to be placed within respective targeted layers. The decision regarding which layers would be treated was done within 24 hours after running open-hole logs. If layers were missed, the plan was to perforate any missed layer at the appropriate time during the treating operation, but this would have lessened the efficiency of the treating operation.

The installation sequence began when the top and bottom of each target layer was known. An accurate tally was made at the rig site of all pipe joints between TAP valves, TAP valves with handling pups, and spacer pup joints.

One valve was identified as the reference valve (red valve in Figure 7), and a virtual model was generated indicating where the valves will be located in each layer. In this well, the TAP starter valve was chosen as the reference valve because of the very thin targeted layer.

Also included in the virtual model was the tolerance accumulation expected. The green ban indicates the +/- 1 ft depth correlation tolerance. The red ban is the accumulative tolerances of the threaded connections. Note this (red ban) tolerance accumulation is bigger.
Before running the TAP valves in the hole, different numbers of shear pins were placed in consecutive TAP valves to assist in verifying the correct valve opens when a dart was dropped. In this well, the shear pin values for the valves were, TAP starter: 1,620 psi, TAP #1: 1,080 psi, TAP #2: 1,620 psi, TAP #3: 1,080 psi and TAP #4: 1,620 psi.

The TAP starter was the first valve torqued to the casing string, and a ¼-in. control line with protective encapsulation was connected to the top of the TAP starter valve. A LaSalle clamp was placed over the control line directly next to the connection and at every casing coupling until the next TAP valve.

The control line was cut off from the reel with extra length. Next, the encapsulation was stripped back and an accurate cut to length was made. This control line was terminated at the bottom of the next TAP valve, and another LaSalle clamp covered it. This was repeated until the top TAP valve was installed. The control line port on the top of the top TAP valve was plugged. No control line was needed above the top TAP valve. It took 20-30 minutes extra rig time per valve to install the TAP valves.

Once in the hole, the final depth adjustment was done using a gamma ray with casing collar locator (CCL) depth correlation log prior to the cementing operations. As in any depth correlation, the gamma ray signature was used to tie the casing depth to the open-hole log depth. The collar just above a reference TAP valve generated a sharp indication on the CCL log and was the reference point to set on depth. The casing was then moved up about 7 ft until the reference valve was on depth. Once the reference valve was on depth, the logging tool was lowered 100 ft below the lowest valve, and a gamma ray with CCL log was generated across all valves.

This log was then compared with the pre-job depth analysis. Once placements were reviewed and accepted, the casing was marked at the rig floor. The well was placed on circulation while the cement crew rigged up. A normal cementing operation was completed using a special cement wiper plug. Care was taken to keep casing on depth when setting the casing hanger after cementing. This kept the reference valve within the +/-1 target depth.

This TAP completion demonstrated that the placement of one reference valve can be within +/-1 ft, relative to the open-hole log at any depth in the well. TAP valves installed within +/-1,000 ft from the “reference valve” can be realistically placed +/-3 ft, assuming a good selection of pup joint lengths are provided. Additional placement tolerance may be needed for valves farther than 1,000 ft away from the “reference valve.”

Also worth noting is that the lowest stages on all TAP completions to date have been perforated. At least one perforation hole is needed below the TAP starter valve. The TAP starter valve sleeve needs to travel 1 ft downward to fully open and thus requires 1 ft of casing volume to be displaced. There is little cost difference from perforating one hole or the entire first stage. Therefore, the first stage has been perforated prior to rigging up the frac equipment at the well site.
Seventeen days after cementing, three wireline runs were made in this well. A cement bond log (CBL) was run with a gamma ray and CCL. This log confirmed good cement behind the casing and reconfirmed the locations of the TAP valves were all within the targeted layers.

A 3.5-in. diameter gage was run next to the depth of the TAP starter valve (9,480 ft) to confirm TAP valve C-rings had not been prematurely squeezed. Also worth noting is that a broken control line will not pre-deploy the C-ring. Pressures above bottomhole hydrostatic pressures are required to initiate the C-rings to be squeezed. The final wireline run per- formed the lowest stage.

All layers in this well were to be treated at 80 bpm; therefore, the treatment wellhead manifold was installed on top of a tree saver. The treatment manifold had four 3-in. slurry inlets plus a 4-in. vertical bore access to launch darts. A 4-in. plug valve with remote actuator and a tee was placed above the inlets. TAP darts are placed in the bore above the closed plug valve. All TAP darts were launched at full rate (80 bpm) by opening the plug valve and chasing the dart into the flow stream by pumping 2-3 bpm above the dart for ½ minute.

Figure 8 shows the actual treating pressures, flow rates and prop concentrations as recorded in continuous time. The fracture treatment started promptly in the morning at 09:01 and finished at 17:36, 8 hours and 35 minutes cumulative time. All six layers were treated independently, totaling 30,124 bbl of slurry and 634,720 lbs of proppant.

The well was completed three days early and the well site treating operation was efficient, with the pumps running over 86% of the time.

Figure 9 breaks down how the time was spent. Normal treating operations, including pumping time and the time to measure instantaneous shut-in pressures (ISSP), amounted to 57.9% of the well site operation. The TAP-related time was reloading darts and waiting for darts to seat, and amounted to 10.3% of the operation time.

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It is possible the opening pressure for Stage 6 could be either the valve shear pinned opening pressure or the fracture initiation pressure. Because the steep pressure drop after the pressure spike is consistent with the other stages, it is most likely the 1,820-psi pressure across the dart was the valve shear pinned opening pressure.

The important point is that the fracture initiation and flow rates into the fractures were established instantaneously with the TAP valves opening. There were no issues breaking down the formation and increasing flow rates. All stages were treated 100% as per the pre-job plan.

The well began to flow back as the frac crew was loading up. After two days of unloading, the well was producing 20% more gas than an offset well. Though encouraging, a 20% variation in production from well to well is very typical in this field. The well flowed for 37 days before the darts were milled. The darts were not causing a noticeable pressure drop during flow, but the darts needed to be removed to allow production logs to be run.
OTHER TAP COMPLETIONS
As of the end of November 2007, 37 TAP valves had been installed and treated in 11 wells. Two other wells have TAP completions installed with a total of 17 valves, but have yet to be treated. One of these wells has 11 TAP valves installed. The deepest installation was 13,800 ft, and the hottest was 240°F. The TAP valves are rated to 15,000 psi maximum annulus pressure, 20,000 psi maximum absolute ID pressure and 325°F.

There have been two fracturing treatments that have screened-out with TAP completions installed to date. In the first incident, the third TAP stage screened-out, leaving 50 bbl of proppant slurry and the TAP dart in the wellbore. This well was allowed to flow back for several days to clean up and unload the proppant. Afterwards, the fracture treatment resumed, using the original dart to open the TAP valve. Following

Figure 9: Normal treating operations, including pumping time and the time to measure instantaneous shut-in pressures, amounted to 87.9% of the well site operation. The TAP-related time was reloading darts and waiting for darts to seat, and amounted to 10.3% of the operation time.

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Totals 438.9 9.0 22.4 30.1 9.3 509.7
%
86.1% 1.8% 4.4% 5.9% 1.8% 100.0%

Figure 10: The fracture initiation pressures were monitored closely. The shear pins in the TAP valves were selected to shear at 1,080 and 1,620 differential pressure across the dart. Only Stage 6 was above the shear pin nominal setting by 200 psi.
that treatment, the next TAP valve caught the next dart and completed the well.

Another screen-out in a different well left 8 bbl of proppant slurry in the well-bore. Four attempts were made to open the TAP valve by pumping up to 10,000 psi surface pressure. There was no definitive indication of opening, although leak-off was observed. The well was allowed to flow back overnight.

The next day the fracturing treatment for this layer was completed. However, the C-ring in the next and final TAP valve did not catch the dart. This was due to proppant across the control line screen when the valve opened, effectively plugging the control line port. The final layer was perforated conventionally.

An incident, unrelated to a screen-out, involved shutting down overnight after nearly completing a fracture stage and leaving the dart to fall and seat without immediately opening the TAP valve. Proppant settling on top of the dart created a plug such that the TAP valve could not be opened. As the well would not flow, coiled tubing was required to wash out the proppant.

Afterwards, the TAP valve was opened using the original dart and the fracture treatment for this layer, and the following two TAP layers were completed without further incident.

These experiences, though frustrating at the time, illustrate the recovery operations to be very similar to typical plug-and-perforate multiple-layer completions. Two of the three recoveries successfully continued after flowing the well. All three recoveries used the original darts to shift the TAP valve open.

CONCLUSIONS

1. TAP completions offers an efficient means of isolating individual layers during the fracture treatment without interventions in cemented case-hole wells.

2. TAP completions can save days of completion time and provide means to efficiently treat all layers independently for optimum production.

3. Fracture initiation does occur through the ports of a cement valve without perforating. Fracture initiation pressures have not been an issue and have typically been lower than the opening pressure of the valves. Once fractures initiate, breaking down the formation and increasing flow rate has not been an issue.

4. Fracture initiation pressures are expected to be the same as open-hole or lower.

5. Recovery from screen-outs is very similar to conventional plug and perforate completion. If the well will flow, then flow the well and leave the dart in the bore. After the sand is unloaded, pump the dart back down on the TAP Valve seat, open the valve and resume the treating operation. On the one well that did not flow back, coiled tubing was used successfully to wash the sand and use the original dart to open the TAP valve.

References

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