INFLATABLE TECHNOLOGIES – THE KEY TO COST EFFECTIVE INTERVENTION?

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Introduction

The optimum design for offshore wells is one that requires minimal intervention work from the beginning of production to P&A operations. The only intervention that is generally acceptable is wireline work. Operators would prefer to avoid interventions, but even the best thought-out plans and designs may not perform as expected over the life of a well. Furthermore, there is a large inventory of producing wells that will require some form of intervention. With technological advances, many interventions can be done without the need of an expensive offshore rig by using coiled tubing and wireline. Using these deployment methods, operators can run many mechanical tools to correct problems and bring a well back on production. In some instances, however, a mechanical option may not be possible due to restrictions in a wellbore. In that case, inflatable tools can be used to help implement the needed solutions. Some examples of situations benefiting from inflatable tools are:

- Plug-Back Operations
- Squeeze Cementing
- Repair of Leaks
- Setting of Temporary Barriers
- Well Integrity Testing

This article will highlight the typical inflatable products and their uses. Case histories will also be included.

Inflatable Sealing Element

Inflatable packer technology has been around for decades and has been utilized extensively in all areas of the oilfield. The same advantages that have made these tools attractive for diverse drilling applications also make them ideal for well interventions. They achieve better results compared to the common alternatives. This is because inflatable tools can pass through restrictions and then inflate to two to three times their original uninflated outside diameter (OD). Moreover, they are easily deployed using all traditional methods (both conventional/coiled tubing and wireline) and are robust enough to withstand harsh downhole conditions.

Some advantages of using inflatable technology is its ability to do the following:

- Pass through a restriction and set elements in inner diameters (IDs) two to three times the manufactured OD of the inflatable element
- Set elements in different tubulars of multiple sizes in a single trip
- Set and retrieve elements without potentially damaging the ID of CRA (Corrosion Resistant Alloys) tubulars
- Perform two different functions in a single trip, such as locating a leak and then pumping cement to seal off the leak
- Perform interventions on upper completions without subjecting the producing formation to kill weight fluids
- Live well interventions using coiled tubing or wireline conveyance of the tools

There are two main types of inflatable elements: open hole and cased hole. Open hole inflatable elements are constructed with a weave structure that allows them to conform to open hole shapes. For tubing or casing applications, the cased hole inflatable element is constructed with slat material. The three basic parts of the inflatable element are the inner elastomer bladder, the support structure (slats or weave), and the outer cover.

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Fluid is pumped into the bladder to inflate the element. As the bladder expands, the slats and outer cover are pushed outward, increasing the OD of the element. After the OD of the element contacts the ID of the wellbore, the pressure inside the bladder continues to increase until the setting pressure is reached. The slats or weave provides the mechanical support so that the bladder can hold that pressure, and the outer elastomer cover creates the hydraulic seal. Figure 1 shows an example of an inflatable element.

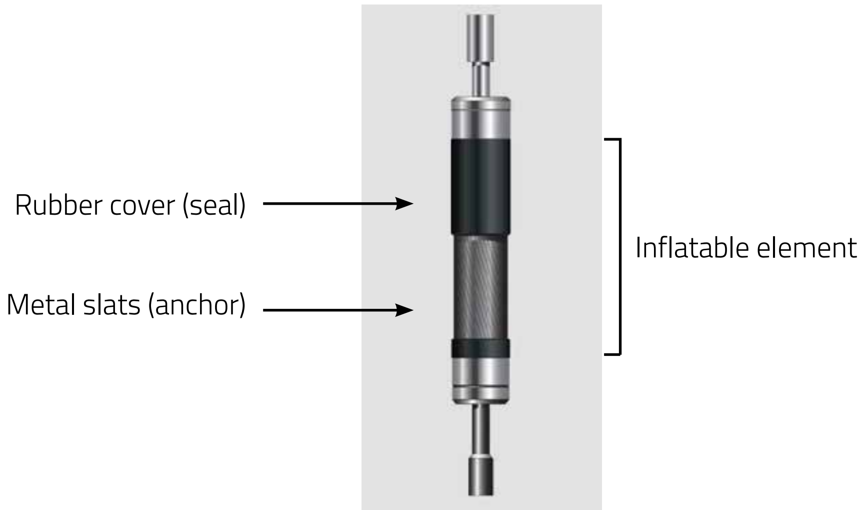


Figure 1 – Example of a Cased Hole (Slat) Inflatable Element

For casing and tubing applications, to provide anchoring, a section of the outer elastomer cover is removed to expose the slat structure. Since inflatable packers don't have conventional slips, such as are used on mechanical tools, the slats create the metal-to-metal friction that anchors the inflatable element when it is subjected to a differential pressure load. Inflatable elements are available in sizes as small as 1-11/16 in. OD and as large as 15 in. OD. The differential pressure rating of an inflatable element is dependent on the temperature of the well at the setting depth and on the element's expansion ratio. The expansion ratio is the ratio of the ID of the wellbore at the setting depth to the element's manufactured OD. For instance, if a 2.90 in. inflatable element is set inside 7 in. casing with an ID of 6.1 in., the expansion ratio would be 2.1. Figure 2 shows a typical performance graph of a 2.90 in. inflatable element versus various casing hole sizes. Corrections may be required for temperature and wellbore fluid exposure.

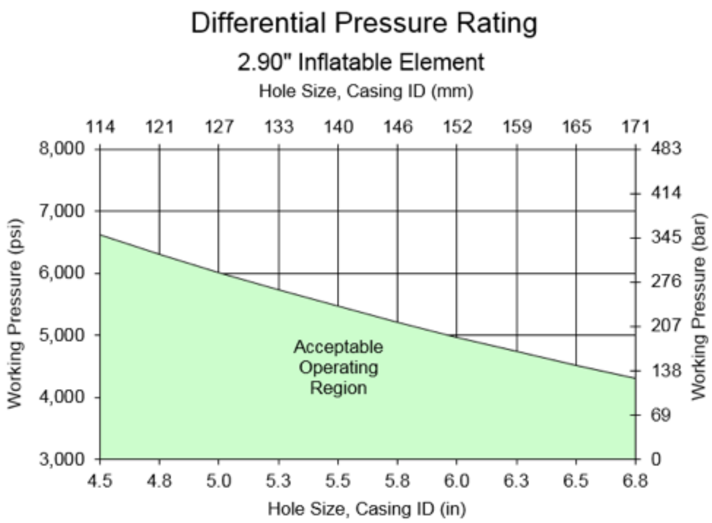


Figure 2 – Differential Pressure versus Hole Size for 2.90 in. Inflatable Element

Inflatable Tools

There are two basic types of inflatable tools: single set and multi-set. Single set tools can be either permanent or retrievable, whereas multi-set tools are typically retrieved after completing an operation. Both single set and multi-set tools can have two elements, which are used to configure a straddle. An example of a single set operation using straddles is when a portion of the wellbore must be isolated but production from below is still required. In such an application, the inflatable tools are separated by blank pipe. An example of a multi-set application using a straddle is when individual zones must be treated with acid or chemicals. In this treatment setup, the inflatable tools are separated by a perforated pup joint.

Any inflatable element can be set up to function as a single set or multi-set tool, serving as a packer or bridge plug. The particular application determines the tool chassis that the element will be placed on. For any application, the configuration will always include some form of release tool. The release tool can be hydraulically actuated or mechanically actuated (by pulling on or rotating the tool). All tool configurations also have a setting mechanism. Depending on the application, the setting mechanism may be actuated by dropping a ball, manipulating the pipe or coiled tubing, or using downhole electronics that control the inflate function.

If plans are for a single set bridge plug to be retrieved, the tool must have the ability to equalize the pressures above and below the inflatable element. For a permanent single set bridge plug, the equalization function is not required. If a single set bridge plug is designed to be permanent, the same procedure used for a cast iron bridge, i.e., dumping cement on the plug, should be followed. If a single set bridge plug is planned to be retrieved, efforts must be made to protect the top of the bridge plug. Sometimes during the intervention above the bridge plug, cement debris falls onto it; if that is likely to happen, the recommendation is to place sand on top of the bridge plug. The debris and sand can then be washed off before the plug is retrieved.

For multi-set operations, the setting mechanism selection is crucial. As previously mentioned, the setting of the element can be initiated by pumping a ball to the tool or by manipulating the pipe or coiled tubing. Both have their own advantages and limitations. For instance, if you want to be able to circulate through the tool during its deployment, a ball-activated system is better, versus an auto-inflate setup that works through pipe manipulation.

Job Setup

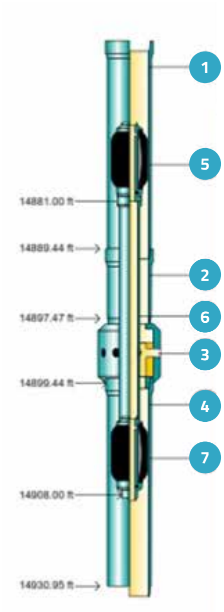
Reviews of historical data have shown that detailed job planning is required to ensure a successful operation. While this should be obvious for any well intervention, certain considerations are especially relevant to interventions using inflatable tools. One such factor to consider is temperature change. A change in well temperature will change the pressure inside an inflatable element: a decrease in temperature will lower the pressure, which could affect the element’s ability to seal, and an increase in temperature will increase the pressure, which could exceed the rating of the element. In most cases, a procedure can be developed that will eliminate any negative impact from temperature change. Another aspect to consider is retrievability. While in most cases an element is easily retrievable, applications featuring large expansion ratios can lower the success rate of retrieval. A database tabulating the results of jobs and testing using particular tools is available to give guidance during job planning. As with any job planning, contingencies are necessary for successful implementation.

Case History

In many well designs, packers are included to isolate certain components, such as a ported sub. In one case, an isolation packer was leaking, which placed sustained pressure on the annulus outside the production tubing. Pulling the completion to replace the packer would have required the mobilization of a rig and millions of dollars.

Installing a scab liner with wireline and inflatable tools used a small fraction of that investment. Since the well had been on production for many years and was in the declining phase of its life, a wireline intervention was planned. Figure 3 shows a schematic of the installed scab liner. The isolation packer that was leaking (not shown) is located two joints above the ported sub.

The inflatable tools had to pass through a restriction of 2.56 in. in the upper completion. They then needed to be set inside 3.5 in. tubing with an ID of 2.995 in. The inflatable packer had an OD of 2.13 in., which gave it sufficient clearance to pass through the restriction and then be set inside the 3.5 in. tubing. A downhole motor/pump tool run on wireline was used to inflate and set the two packers. The first run correlated and set the lower packer. The second run stabbed into the PBR (Polished Bore Receptacle) of the lower packer, which had a collet configuration, and then the upper packer was inflated. The well was placed back on production with flow going through the ID of the scab liner. The integrity of the annulus outside the production tubing was established, and the well was brought on line successfully.



Item	Desciption	L.D.	O.D.	Length (ft)
1	Tubing	2.992	3.500	31.62
2	Pup Joint	2.992	3.50	8.03
3	Ported Sub	2.949	5.000	1.97
4	Tubing	2.992	3.500	31.51
5	Upper Inflatable Packer	0.96	2.13	6.75
6	Scab	1.38	1.66	24.00
7	Lower Inflatable Packer	0.96	2.13	6.75

Figure 3 – Scab Configuration

As previously mentioned, inflatables are routinely run on coiled tubing. In another case, a multi-set inflatable tool, using the option to run on coiled tubing, was set as a barrier to perform an injection test. The operator wanted to add another set of perforations for injecting a treatment. To do that, the existing perforations (below the added perforations) would need to be isolated. The plan was to set an inflatable above the lower perforation interval and do an injectivity test down the coiled tubing / tubing annulus.

The wellbore was completed with 7 in. casing with an ID of 6.18 in. To pass through a restriction of 5.86 in. in the upper completion, a multi-set tool with an inflation element having an OD of 3.75 in. was selected for the job. Wellbore deviation was 74 degrees. Because of the high angle, pumping a ball to initiate inflation was not desired. Furthermore, setting depth was approximately 18,000 ft, which meant it would take a lot of time to get the ball to seat. Instead an auto piston device was used; where engaging the pumps would inflate the packer. Once inflated to the desired pressure, weight would be set down to isolate the inflation pressure. The injectivity test began and lasted about 48 hours. Once the objectives of the test were completed, the packer was released and pulled out of the well.

Conclusion

Most well designs try to include the ability to run mechanical tools should they be needed for well interventions. However, older wells and wells that develop unplanned issues will often require the use of inflatable tools to perform needed well interventions. As with any job, it is critical that pre-job planning take into consideration all parameters that exist before, during, and after the intervention. This will help ensure the safe deployment, execution, and (if desired) recovery of the inflatable tools.

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