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Research Article

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Application of Visio Software in the Design of an Intelligent Well Completion for Multiple Zones without Commingling

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Abstract This work studies the design of an intelligent/smart well completion system for multiple zones to prevent commingling by the elimination of the use of conventional wireline method which was replaced with ½ inch flowline connected to the Sliding Sleeve Door (SSD) and a modified Landing Nipple having a flapper installed on it. The Sliding Sleeve Door (SSD) and the flapper are activated with an opening pressure of 5000psi and a closing pressure of 0psi. The pressure is activated from the surface through the flowline. For a multiple well completion with three zones if a zone is to be produced other zones are isolated by activating a closing pressure of 0psi on the Sliding Sleeve Door (SSD) and the flapper on the Landing Nipple. The 0psi closing pressure of the Sliding Sleeve Door (SSD) and the Flapper is achievable due to a return spring attached to them. Once the return spring senses a zero psi it will relax causing the Sliding Sleeve Door (SSD) and the flapper to close thereby creating well isolation in their respective zones, hence preventing commingling of fluids from those zones.

Keywords Intelligent well, smart well, multiple zones, co-mingling, zonal isolation

1. Introduction

Engineering for oil and gas survey is one of the most difficult projects since it frequently encounters issues like deep water, limited space, a challenging environment as well as challenging monitoring. Exploiting oil and gas resources is becoming easier as development takes place, and many oil and gas areas have high recovery rates. Intelligent/smart well completions technology based on mechatronics and digital communication technology has been presented to address the difficulties that is faced with during oil and gas production.

It has gained much popularity and is now gradually being requested as a standard method of oil and gas development in the oil and gas industry. Oil and gas production is now subject to more regulations and oversight than ever before, necessitating rapid innovation in exploitation technologies. The superiority of intelligent/smart well technology has progressively become clear to a significant number of experts in oil and gas development.

Continual and real-time reservoir management is made possible by intelligent/smart well completion, a production well's full system. Forming a closed loop control is the technology's key goal. In order to provide real-time feedback to the uphole system, the well sensor collects data such as downhole pressure, temperature, flow rate, and composition. Following that, the exact same data will be thoroughly processed, examined, and assessed on the software platform. The downhole production tool is then given a reservoir management decision instruction, which is then sent to it via the wireless communication control system for remote operation.

Intelligent well technology helps in bridging the gap between above and below ground. Its unique use in reservoir development focuses mostly on enhancing recovery by optimizing production and controlling occurrence. Intelligent well technology has the ability to automatically shut down in order to stop crossflow and water cuts that could influence production in the near future.

The introduction of intelligent well systems (IWS) offers the promise of independently monitoring and controlling production from each zone to optimize a well's flowing parameters. IWS utilizes remotely controlled sliding sleeves (also known as downhole regulators, valves, or chokes), tubing and annulus pressure gauges, and, in some cases, downhole flowmeters and temperature gauges. The use of IWS technology, also known as intelligent well completion (IWC), is currently widespread around the world to fulfill the promise of improving production for optimum recovery and enabling reservoir management. Following the introduction of IWS, production rates in some wells have doubled. In other instances, IWS functionality has allowed operators to create reserves that would have gone unnoticed otherwise.

An intelligent well completion system has the ability to better manage well and production processes by gathering, transmitting, and evaluating completion, production, and reservoir data.

As a result, the value of cognitive well technologies stems from their capacity to actively remotely alter zonal completions and flows through flow control as well as to continuously track the behavior and performance of the zones through real-time downhole data collecting. Intelligent/smart well completion system has been used to optimize completions in electrical submersible pump (ESP) and commingled, multilateral, sand control, and completions successfully.

2. Materials and Method

Description of Materials/Equipments

2.1 Tubing

The typical flow channel used to carry fluids to the formation and produced hydrocarbons to the surface is tubing. Tubing with a packer isolates the casing from well fluids and guards against corrosion damage to the casing. Moreover, multi-completions need tubing to enable independent zone production and operation.

An injection or production well must operate safely, which depends on the quality of the tubing. The following characteristics must be present in the design of tubing that is chosen:

i. To reduce the overall pressure loss, the ID (Inside Diameter) of the tube must give a produced fluid velocity (tubing performance relationship).
ii. The completion string needs to be able to endure the highest possible inner influence and power.
iii. The tensile strength of the tubing and coupling string must be high enough to allow suspension of the entire string before fatigue loading.
iv. Throughout the well's life, the tubing must be resistant to the chemical corrosive action of well fluids.
v. The completion string needs to be able to endure the highest possible collapse (external) differential pressures between the annulus and the tubing.

Tubingless unique completions exist. They are fitted in flowing wells with relatively modest-sized casing.

For items like casing and tubing that are tubular, API has established a number of standards. Nine steel classes have been established by API: H40, J55, K55, C75, L80, N80, C95, P105, and P110. The primary purpose of the letters H, J, and N is to prevent ambiguity, but other letters have additional meanings: K has a higher final P is stronger than J, but C and L have "limited yield strength" and stricter standards. The minimal yield point, expressed in units of 1000 psi, is indicated by the numbers following the letter grading. The production procedure or later processing of the steel to change its qualities is indicated by the letter grades. In general, steel is much more vulnerable to H_2S failure the higher the yield strength produced by working the steel.

The primary failure modes that tubing is dealing with are:

i. Burst
ii. Collapse
iii. Tension - failure of the couplings or pipe

The majority of the time, killing operations, well service, and pressure tests involve the most severe loads on tubing. The specification of material grade (quality), operational characteristics, size, thread, and connection type are necessary for choosing a tubing material.

To enable effective installation of artificial lift equipment and efficient fluid flow, tubing strings must be the right size. The productivity may be hampered by excessive friction losses if the tubing string is too small. It can also significantly limit the kind and size of artificial lift equipment.

On the other hand, if the tubing string size is too large, it might result in heading and erratic flow, which can clog the well and make workovers more difficult. Often, the tubing's outer diameter (OD) is stated. Via the "weight per foot" of the tubing, the steel wall thickness determines the internal diameter (ID). The tensile strength of steel and its resistance to failure with substantial exterior (collapse) or internal (burst) pressure differentials will be influenced by the thickness of the wall.

Because each junction suspends the string directly below it, the weight of the suspended pipe places the highest tensile force on the joints closest to the surface.

The differential pressure between the internal and external pressures is the most crucial factor to take into account when designing a tubing string. The surface, where the external pressure is at its lowest, frequently experiences the highest burst condition.

The pressure whenever the string is gas loaded plus a safety factor that ranges from 1.0 to 1.33 typically equals the maximum design burst pressure.

Tubing collapses when the inner pressure is greater than the exterior pressure. When the annulus is full of fluid and the tubing is evacuated at the bottom of the well, together with a safety factor that ranges between 1.0 to 1.125, this situation is typically at its worst.

2.2 Tubing hanger

The tubing hanger is a tool mostly used for installing back pressure valves, hanging completion string, and setting plugs. Typically, wireline, drill pipe, or other methods are used to activate the isolation devices previously stated. An isolation mechanism is included within the hanger. When BOP is hung down from the well, in particular, this equipment aids in scooping out undesired objects like metal rubbish and debris that may otherwise fall onto the well. It contains a port where control lines can be connected to operate the sliding sleeve door (SSD), surface control subsurface safety valve (SCSSV), and, if necessary, the permanent down hole gauge (PDHG). Typically, the numerous control wires are attached to the hanger's bottom and connected at the top for future attachment to the wellhead or Christmas tree ports. Certain tube hangers are made to let the control lines move continuously from the bottom to the top of the control line. Some, however, have a discontinuity configuration, in which the line is fitted at the base, terminated, and then reconnected at the top for further connection to the production tubing. It is typically preferable to use the continuous configuration of the control line, which enables the control line to run through the hanger to the top and on to the well head machinery, in order to prevent leaks.

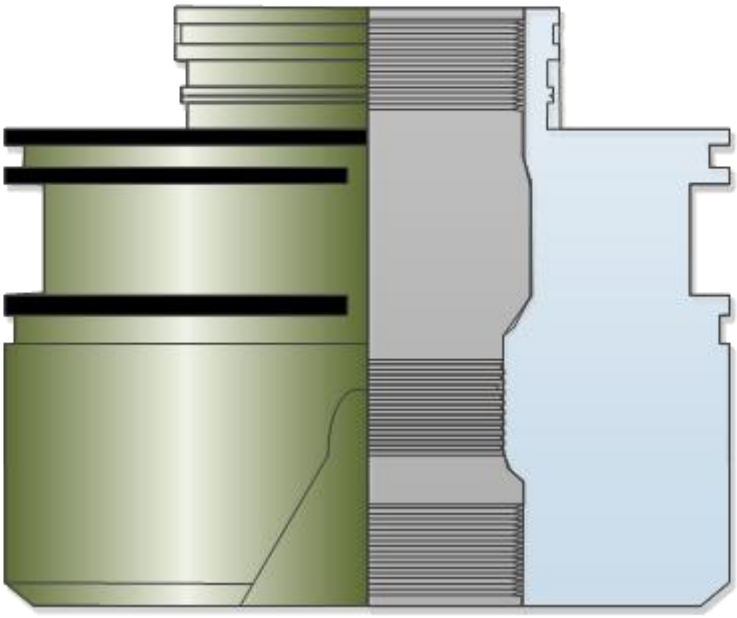

Figure 1: Single Tubing Hanger

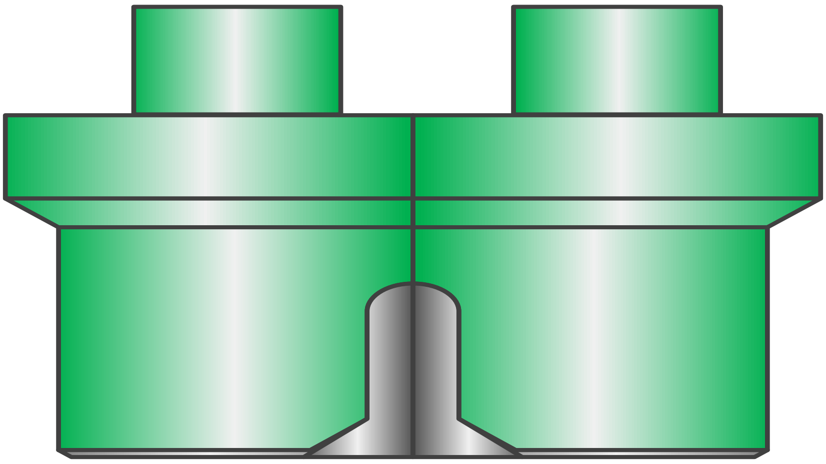

Figure 2: Dual Tubing Hanger

2.3 Landing nipples

The installation of plugs for pressure isolation and other down-hole purposes can be accomplished using landing nipples, which are short completions accessories with an internal profile. In order to insert plugs, gauges, and other down-hole tools into the tubing string, these plugs are often deployed via wireline operation and sometimes by using coil tubing.

There are many ways to employ wireline for tool delivery in completions operations, which include:

i. Plugs are deployed using wireline for pressure testing, well isolation, and well suspension applications, such as the activation of hydrostatic set parkers.
i. Standing check valves for pressure testing.
ii. The use of memory (or wireless telemetry) gauges to measure pressure buildup (PBU) and also to analyze it.
iii. Has sliding sleeves [sliding side doors (SSDs)] that can be moved.
iv. The installation of downhole chokes.
v. Siphon or velocity string landing.
vi. Storm choke valve placement or the insertion of a wireline retrievable valve

There are two ways to set down such objects:

vii. Inserting a lock into a completion-preinstalled nipple profile.

The lock will have a blanking plug, standing valve, gauge, etc. attached to it.

viii. Employing a packer (bridge plug) that may be placed anywhere in the tubing and is deployed using wireline (slickline or electricline). The packer has a stopper, standing valve, gauge, etc. attached to it.

The locking mechanisms of the landing nipples are not interchangeable due to the landing nipple's seal bore, internal profile, and NO-GO profile, which frequently vary depending on the configuration established by the original equipment maker (OEM). According to experience, the NO-GO profile on the landing nipples is primarily used for effective depth control.

The NO-GO characteristic of the landing nipple is often used to initiate some sort of downward force in order to test pressures from the top; however, employing a well-designed locking system in the string renders this practice ineffective.

The NO-GO is primarily intended for depth location and is not intended to carry loads. Thus, pressure should not be applied to help the plug locks into the nipple profile where the loads are taken at the locking dogs or plugs. The interior diameter of the nipple is progressively decreased by the No-GO profile. This size reduction imposes some limitations on the tools that can be used to isolate each zone as needed by running them via the top completion down to the lower completion.

The nominal profile sizes with no-goes are in the 0.06 inch range.

For the sole purpose of this course work, nickel is employed in the following areas.

1. To create isolation when it becomes necessary to remove a Christmas tree or to nipple down BOP, a nipple profile could be put beneath the tubing hanger. Velocity strings are held in place within the production string using Nipple NO-GO profiles. By putting nipple no-go just below the downhole safety valve, a wireline safety

valve or insert safety valve could be installed. At this stage, a velocity valve might also be placed on the landing nipple with great caution due to the potential for the site to obstruct the free flow of well fluid and render the safety valve. In order to pressure test the tubing string and leak-probe the tubing connection after makeup, a landing nipple can also be put in the center of the well string. The likelihood of utilizing a landing nipple at mid-string is reduced due to the use of metal to metal seal of premium thread connections, which almost eliminates the possibility of having leakages along the production well string during completion runs. However, for this to be possible, a blanking plug will have to be run with an e-line or wireline, which will also add to the cost. A design that incorporates a landing nipple inside a sliding sleeve door to serve as a backup also includes sliding sleeve doors that are hydraulically operated. Additional string testing can be done by installing landing nipples at the top of the production well string, a few feet above the parker, to set up a type of standing valve for testing the production well string's integrity as well as the parker, particularly hydrostatic set parkers, is about to be set. However, this may not be too practical given the ongoing evidence of the hydraulic parker's integrity. In some cases, the string could be checked below the parker at a low pressure test rate that is much lower than the parker's setting in order to ensure the parker doesn't set too soon while the test is being done. In order to establish the parker and a deep set plug that will function as a deep set barriers for work-over operations all around top hole interphase, the same Landing nipple profile that was used to position the parker below the parker for the low pressure string integrity test could be employed. Some designs incorporate a landing nipple contour to act as a barrier over perforated tubing or pup joints near the tailpipe. This is done to provide a framework for the installation of a storage gauge in wells that are productive and have high flow rates without interfering in any way with the flow of the fluids. Certain wells, however, were built with surface read-out gauges, which obviously precludes the use of a deep-set memory gauge. Moreover, a nipple profile could be made to work with a cemented liner or sand filters so that blank plugs can be installed to regulate the flow of fluids in a specific zone of interest. This type of design has the disadvantage of potentially interfering with cementing operations and liner cleanout operations by the use of liner strings. Instead, if a non-cemented liner string is used and the landing nipple profiles are specified, installing it in a different position with equal circulating pressures or expandable elastomeric parkers will make it much more economical and preferred.

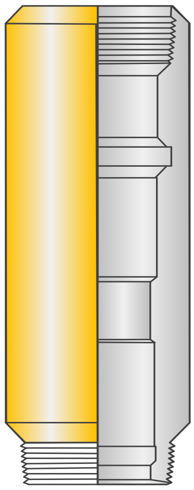

Figure 3: Landing Nipple

2.4 Sliding sleeves

To gain access from the tubing to the annulus for fluid circulation or to create a previously isolated zone, sliding side doors or circulating sleeves are used.

They use a wire-line instrument to close and open. Also, packers are placed above these devices. In order for multi-zone completions scheduled for selective production to take place, there are some crucial prerequisite that need to be considered.

The following are some applications for sliding sleeves:

i. Kick-off by displacing the fluid inside the tubing with a low density fluid, in so doing reducing the need for coiled tubing inside the production tubing.
ii. Well killing before work-over or tubing pulling.
iii. Dispersing completion fluid and packer fluid (i.e. from mud, brine and reserved water).
iv. Examining (SSSV).
v. Creating a specific zone inside the tube momentarily.
vi. They are now far simpler to open and less likely to malfunction.
vii. Certain fluids require special elastomers.
viii. In some cases, a sliding sleeve is swapped out for a ported nipple.
ix. As a different option, some completion engineers decide to use a side pocket mandrel as a circulation point above the packer.

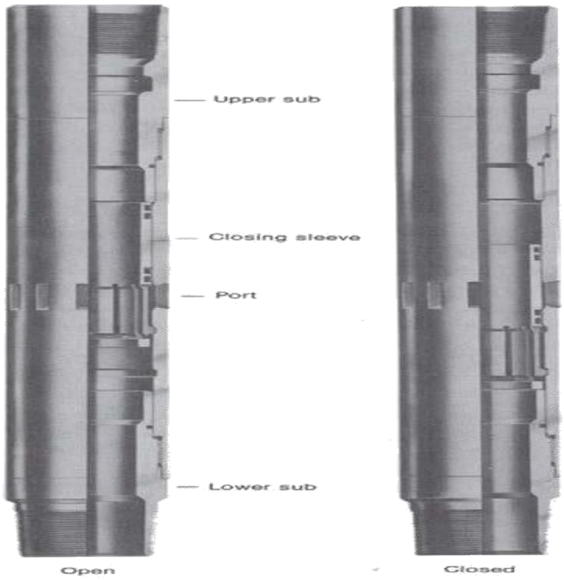

Figure 4: Sliding Sleeves [Bakerhughes, 2014]

2.5 Packers

The cased-hole finishing design is built around the packer. Packers are subsurface devices that create a seal between a well's tubing and casing to stop fluids from flowing past this point. In order to protect the casing and other formations beneath and above the production zone, packers act as sealing devices to isolate and contain generated fluids and pressures inside the wellbore. This is crucial to the typical well's fundamental operation.

Packers have a structural purpose in addition to their sealing function (anchor the tubing to casing). Parkers are used for a variety of purposes, which are:

i. Increasing safety by creating an obstacle for fluid to flow through the annulus (Lake, 2007, Bellarby, 2009, Allen & Roberts, 1982).
ii. To prevent well fluids and forces from contacting the casing.
iii. To prevent corrosion of the annular casing brought on by the generated fluids and high pressures.
iv. To keep the tubing string from moving downward.
v. To help bear some of the tubing's weight.
vi. To enhance flow characteristics and avoid heading.
vii. To divide zones inside a single wellbore.
viii. To separate gravel and sand (gravel pack packer and sump packer).
ix. To inject killing or therapeutic fluids into the annulus of the casing.
x. To pack off holes instead of using squeeze cement.
xi. To maintain hydraulic power fluid injection pressure and gas lift pressure separate from the formation.

Understanding the completion and operating requirements is necessary to select the appropriate packer.

Operations and maintenance and completions engineers are now under pressure to complete designs quickly or risk an early workover to replace a badly chosen packer.

Four essential parts make up a pack: a cone, a slip, a system of packing materials, and a body or mandrel (Figure 3.1.5). The slip is an instrument with a wedge-like form with wickers or teeth on its surface. When the packer is set, these wickers or teeth pierce and grab the casing wall. When force is applied to the packer, the ramp-shaped cone, which has a beveled shape to match the slip's back, sends the slide outside and into the casing wall.

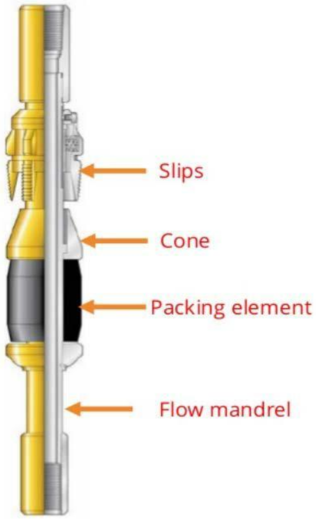

Figure 5: Packer components [Lake, 2007]

Packers can be divided into two categories: those with mechanical or hydraulic setting mechanisms and those with wireline or tubing operating mechanisms. They may also be permanent or retrievable.

In the process of pushing a pair of conical slips outward and into the casing wall, mechanical set packers press a cone- or wedge-shaped tool against by the slips. Compression, tension, and rotation of tubing provide mechanical energy.

The exhaust must be sealed for hydraulic set packers. A standing valve, plug, drop ball and seat, or smart plug can be used to do this. A differential pressure is created on the setting piston by the tube pressure that is being applied.

The piston is free to compress the slips and component or allow the packer element to travel downward in relation to the slips when a shear pin connecting it to the piston breaks (Figure 3.26). The packer slips are made with the intention of holding in one direction, either as an anchor to oppose upward movements or as a hanger to resist downward movement. If two sets of opposing slips are utilized, the packer can be anchored from opposite directions. An accompanying packing component expands in response to the slip-setting action of the tubing or pressure, sealing the pipe's wall and producing a pressure-tight seal [Bellarby, 2009, Allen & Roberts, 1982].

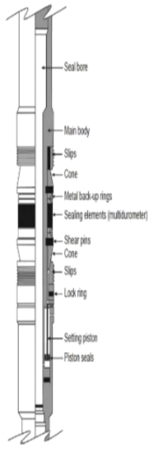

Figure 6: A hydraulic set production packer by Bellarby, [2009]

2.6 9.5/8'' Model XX hydrostatic set packer

These packers use a setting piston identical to divergent set packers, except all or some of the piston surface is acting against an air pressure chamber rather than annulus pressure. As a result, the packer can be set with the help of the hydrostatic tubing pressure. Compared to a hydraulic set Packer, less pressure is needed to provide the desired force. Because of this, hydrostatic set packers are able to use larger mandrels than hydraulic set packers. When bigger tube sizes are necessary, hydrostatic set packers—which are more expensive to build than differential sets—are typically employed. For instance, a differential set packer will function quite fine in 7" casing with 2 7/8" tubing, but if 3 12" tubing is needed, a hydrostatic packer should be utilized because to the smaller piston area caused by the bigger packer mandrel. Numerous packers can be run in a tubing string with selectable setting, and each packer can be set separately from the others. Wireline intervention activates each packer's setup mechanism.

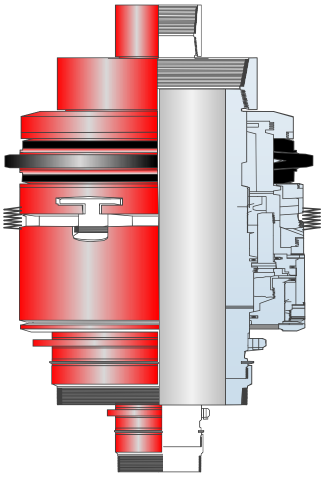

Figure 7: Model XX hydraulically set hydrostatic Packer

2.7 Hydro-trip pressure sub

Parker is mostly set using an instrument called a hydro-trip pressure sub. It consists of an inner ball seat whose internal diameter is similar to that of a typical tubing joint. The Type "E" Hydro-Trip Pressure Sub has a ball seat design that ensures that when the brass screws are sheared, the collet-type fingers will expand into their groove in the top sub, creating a complete opening ID for the passage of tripping balls and wire-line tools. To offer a means of supplying the tubing pressure necessary to activate a hydraulically operated tool, such as a hydrostatic packer, the Model "E" Hydro-Trip Pressure Sub is inserted in the tubing string beneath the tool. The appropriate size tripping ball must be routed through the hydrostatic packer to a seat in the Hydro-Trip Pressure Sub before enough tubing pressure is supplied to engage the packer's setting mechanism. Once the packer is in place, an increase in pressure (to about 2,500 psi) shears the brass screws and drives the ball seat down until the fingers lock into the top sub. The ball then descends through the tubing when the Hydro-Trip Pressure Sub fully opens.

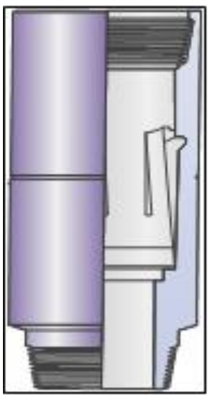

Figure 8: Hydro-trip Pressure Sub

2.8 Coupling flow

Couplings for flow are a device used in flow control. It often acts as reinforcement with a substantial interior wall thickness designed to stop erosion damage brought on by fluid turbulence. To guard against this erosion damage, it is mostly positioned above and below specific tubing string components. The average length of a flow coupling junction is around 10 feet, and it's made of a specific alloy with robust walls to aid and prevent internal tubing string erosion from fluid issues.

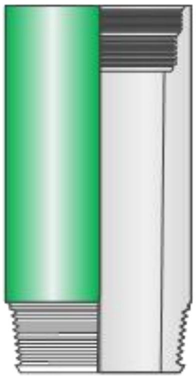

Figure 9: Flow Coupling

2.9 Blast joint

To protect the tubing string from external abrasions, blast joints are created. It is typically produced as a heavy-walled pipe made of a specific alloy and is often offered in lengths of 20 feet. Although, depending on the operation's needs, it can be less than 20 feet. In order to survive the scouring effect of fluid flow from the perforations, blast joints are constructed in a completion string across a perforated pay zone region. As a result, it prevents exterior deterioration.

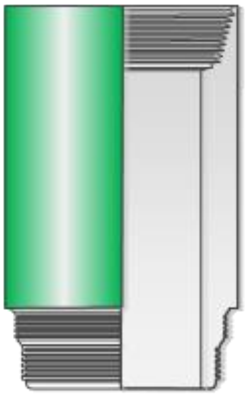

Figure 10: Blast Joint

2.10 Cross Over

Cross overs are pipe junctions with diverse lengths, diameters, and connection types that are used to link pipes with various connection kinds. Two different connection types with the same as:

i. Two different connection types with the same.
ii. It might be made with two different connection types, each with a different internal and external diameter. Swage is another name for this kind of cross over.

Most engineers aim to minimize the number of cross over joints that are included in the completions string design since cross overs are occasionally thought of as the weakest places along the completion string make-up. Figure 3.1.19 below depicts a crossover's optimal geometry. You should be aware that this geometry produces a longer string and a marginal cost that is deemed to be more expensive than completions designs with fewer cross overs. Crossover The quality and metallurgy of the crossing should be identical with the completion tubing, which is the case with all completion equipment. Where the exterior diameter remains constant but the weight, metallurgy, grade, or connectivity of the tubing varies, crossovers may be necessary. Often, coupling stock is used to build these.

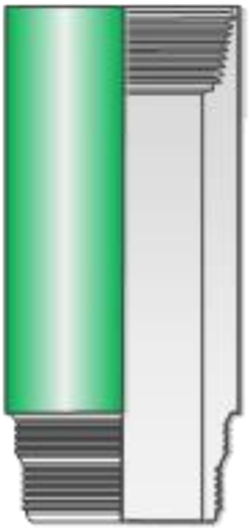

Figure 11: Cross over joints

2.11 Research Design

This project is aimed at designing intelligent well completion system for multiple zones without commingling. The following materials were considered for effective design.

i. Hydrostatic Packer
ii. Sliding Sleeve Door (SSD)
iii. Landing Nipple/Flapper

Three producing zones at differing depths were intended for by this technique.

Producing Zone 1 has a top layer with a thickness of 5 feet and a depth profile of 6270 feet. At a depth of 6447 feet, whereas the second Production Zone 2 is situated at 6340 feet with a thickness of 5 feet, the third Production Zone 3 is to be generated through an open hole. Packer Size 831-292 for 40-53.5lb/ft 9-5/8" CSG W/9.3lb/ft HCS, Baker Model Hydraulic set single string. The three zones were each given a Box x Pin. This packer's purpose is to both stop the fluid from produced wells from mixing with fluid from other zones and from escaping from the annulus to the hanger.

Packer 1 was positioned at a height of 6115.48 feet above the first production zone to stop well fluid from escaping the annulus and mixing with fluid from other zones as well as to prevent it from flowing to the hanger.

In order to stop well fluid from mixing and escaping into the upper and lower production zones, packer 2 was positioned at a depth of 6305.66 feet.

To stop well fluid from migrating from the bottom production zone to the middle and upper production zones and from escaping the well, Packer 3 was positioned at 6410.04 feet.

Sliding Sleeve Door: This was included in the design in order to allow for or isolate manufacturing for a specific zone of interest. A sliding door on SSD can be opened and closed. It prevents fluid from getting into the manufacturing tubing when it shifts near and the opposite is true as well.

At a depth of 6033.92 feet, SSD 1 was created and installed. SSDs 2 and 3 were inserted at 6223.52 and 6320.69 feet, respectively, of depth.

For fluid circulation, SSD 1 was mounted above HS packer 1. SSDs 2 and 3 were installed, whereas SSDs 1 and 2 were used to allow and isolate well fluid, respectively.

A sensor that is put on the SSD, connected to flow lines, and terminating at the surface will start the system of closure and open on the Christmas trees. It's going to be turned on by means of a fluid that is pumped through with a surface pumping apparatus to start an opening and closing pressure. The SSD shifts open, letting well fluid to enter the tube, when the maximum opening pressure is reached. The SSD spring relaxes as soon as the pressure is reduced to its lowest point, allowing the door to close and keeping well fluid from mixing with other fluids in the tubing.

Landing Nipple: OTIS 2.313" x Nipple W/2-7/8" 6.5lb/ft EUE Box x Pin at 6425.76" depth and OTIS 2.205" XN Nipple W/2-7/8" 6.5lb/ft EUE Box x Pin at 6435" depth were the two landing nipples that were placed. The installation of the nipples at this specific depth is done to blank off well fluid from the open hole and prevent mixing. The novel idea entails the introduction of a flapper system that, when required, will open or close by pumping pressure from the surface through flow lines attached to the blanking plug flapper. The flapper will open once a particular maximum pressure has been attained and close once the pressure reaches 0 psi. So, the generation of well fluid from the zone of interest would've been enabled by this process, which would prohibit commingling from occurring in any of the zones.

Table 1: Isolation Equipment Parameters, installed depth and operating pressure

Isolation Equipment Parameters					**Operating Pressure**	
Material Description	**OD (in)**	**ID (in)**	**Length (ft)**	**Installed Depth (ft)**	**Opening Pressure (PSI)**	**Closing Pressure (psi)**
SSD Shift Up to Open 13%Cr W/ 2.313" X Profile, 2-7/8" 6.5# HCS Box X Pin FOR CIRC DIESEL	3.875	2.313	4.01	6,033.92	5000	0
SSD Shift Up to Open 13%Cr W/ 2.313" X Profile, 2-7/8" 6.5# HCS Box X Pin FOR CIRC DIESEL	3.875	2.313	4.01	6,223.53	5000	0
SSD Shift Up to Open 13%Cr W/ 2.313" X Profile, 2-7/8" 6.5# HCS Box X Pin FOR CIRC DIESEL	3.875	2.313	4.01	6,320.69	5000	0
OTIS 2.313" x Nipple w/2-7/8" 6.5# EUE Box x Pin	3.687	2.313	1.01	6,425.76	5000	0

Table 2: Isolation Packer Elements and setting depths.

Materials Description	**OD (in)**	**ID (in)**	**Length (ft)**	**Depth (ft)**
Hydraulic Set Single String Packer Size 831-292 for 40-53.5# 9-5/8" CSG W/ 9.3# HCS Box X Pin #4	8.25	2.5	6.11	6,115.48
Hydraulic Set Single String Packer Size 831-292 for 40-53.5# 9-5/8" CSG W/ 9.3# HCS Box X Pin #5	8.25	2.5	6.11	6,305.66
Hydraulic Set Single String Packer Size 831-292 for 40-53.5# 9-5/8" CSG W/ 9.3# HCS Box X Pin #6	8.25	2.5	6.11	6,410.04

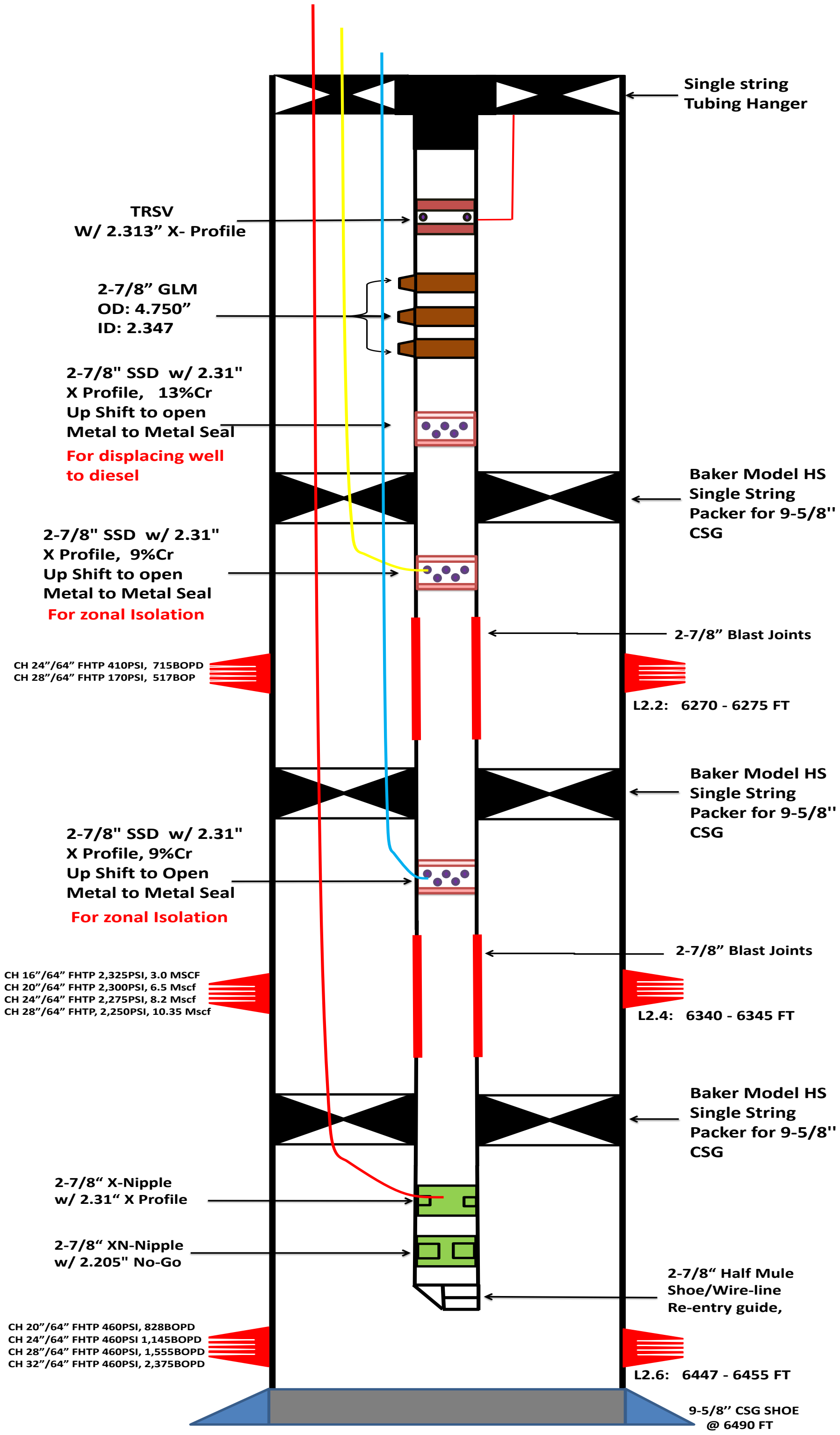

Figure 12: Conventional IWC schematic showing SSD, Landing Nipple and Packer for zonal isolation.

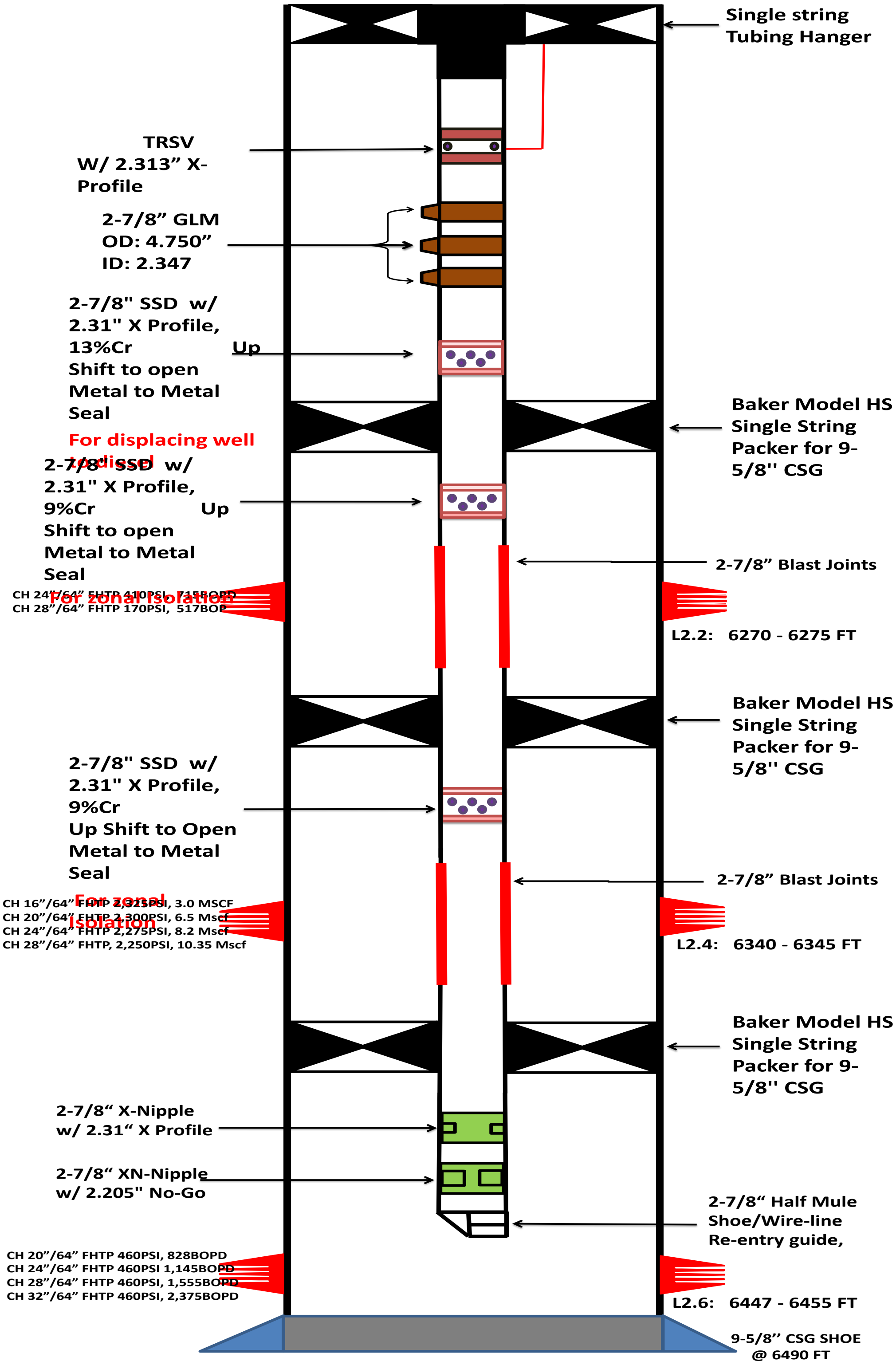

Figure 13: IWC schematic showing flowlines, SSD, Landing Nipple Flapper and Packer for zonal isolation to prevent commingling.

2.12 Source of data

i. Data was obtained from the well's prior well record, which shows how the well was initially finished before re-entry.
ii. Data was also obtained through the workshop preparation of the well string make up.
iii. Data regarding the functionality of the intelligent well completion components was obtained from numerous function tests and pressure tests that were conducted.
iv. Other data was obtained from the equipment data sheet of the original equipment manufacturer.

2.13 Methods of data collection

i. Hydrostatic packer - Baker Model Hydraulic set single string Packer Size 831-292 for 40-53.5lb/ft 9-5/8" CSG W/9.3lb/ft HCS Box x Pin was acquired. The production casing size was determined from the initial well information to be 9-5/8" 47ppf L80 Vamtop BOX x PIN, which equates to 40-53.5lb/ft, after determining the size, grade, and weight of the production casing, necessitating the usage of this model of HS Packer for the intelligent well completion. The packer underwent a workshop volume test to determine whether it could maintain pressure for 15 minutes without leaking. The packing element was fastened with a stopper prior to this test in order to prevent premature setting as the pressure increases. Since the packer's initial setting pressure is 1800 psi, the result was recorded using a chart recorder and a pressure of 500 and 700 psi was applied. Volume testing the packer below its setup pressure was important. The chart recorder maintained consistency at 500 and 700 psi for 5 and 15 minutes, respectively, without a pressure drop, showing that the packer has no leaks and is fit for its intended use. The packer was tested, and the results were reported.
ii. Sliding Sleeve Door (SSD) - The choice to employ a 3-1/2" 9.3ppf L80 CSH Box x Pin Sliding Sleeve Door with an X-profile of 2.813 was made in light of the fact that the well was previously constructed with 3-1/2" 9.3ppf L80 R2 CSH Tubing. The SSD underwent a workshop volume test to determine whether it could withstand pressure for 15 minutes without leaking. The Sliding Sleeve Door was closed before to the test in order to stop leaks. The outcome was captured using the chart recorder, and the SSD was subjected to 4500 and 5000 psi of pressure. The SSD was tested below its yield strength of 7500psi in order to prevent failure. The SSD was used to record these test results. Using a flowline attached to the surface, the opening and closing pressure of the SSD were also tested using opening pressure of 5000 psi and closing pressure of 0 psi. A chart was used to record the test outcome.
iii. Landing Nipple - The decision to use 3-1/2" 9.3ppf L80 CSH Box x Pin Landing Nipple with an X-profile of 2.813 was made in light of the fact that the well was originally finished with 3-1/2" 9.3ppf L80 R2 CSH Tubing. To determine whether the SSD will maintain pressure for 15 minutes without leaking, the Landing Nipple was put through a workshop volume test. On both ends of the connection, our Test cap was fitted prior to conducting this test, allowing it to withstand pressure. A pressure of between 4500 and 5000 psi was delivered into the Landing Nipple, and the outcome was recorded using the chart recorder. The Landing Nipple was tested below its yield strength of 7500 psi in order to prevent failure. The Landing Nipple served as the benchmark for these test results. The Landing Nipple flapper that prevents commingling was also put to the test with an opening pressure of 5000 psi and a closing pressure of 0 psi. A chart was used to record the test outcome.

2.14 Methods of data analysis

i. Computer generated results from the software's of the testing instruments used such as VISIO, WINCAT.
ii. Mathematical model –

For the Landing Nipple Flapper the maximum well pressure would be felt by the entire tubing string after the SSD or flapper is opened and would equal

(Weight of fluid in tubing + tubing string weight + weight of flowline fluid) / Flowline factor (Ff)

Ff = 13.79in

= (13,000lbs + 39,950lbs + 16, 000lbs) / 13.79in

= 5000psi

With the result gotten from the model the maximum opening pressure was determined at 5000psi.

All content should be written in English and should be in Single column.

i. Page type will be A4 with ner margin, word spacing should be 1.
ii. No space will be added before or after paragraph.
iii. The references should be represented as large brackets e.g [1], [2] in the text.

3. Results & Discussion

3.1 Presentation of Data

Table 3: Showing well completion profile with isolation depth for zone B & C.

Pay Zone	Well annulus isolation		Payzone Isolation Device depth (ft)	Payzone Isolation Device		Well Status
	Packer Setting depth (ft)	Packer Status		Isolation Equipment type	Isolation Status	
Zone A	6,115.48	Close	6,223.53	Sliding sleeve door	Shift Open	Producing
Zone B	6,305.66	Close	6,320.69	Sliding sleeve door	Shift Close	Isolated
Zone C	6,410.04	Close	6,425.76	Landing Nipple	Shift Close	Isolated

Table 4: Showing well completion profile with isolation depth for Zone A & C

Pay Zone	Well annulus isolation		Payzone Isolation Device depth (ft)	Payzone Isolation Device		Well Status
	Packer Setting depth (ft)	Packer Status		Isolation Equipment type	Isolation Status	
Zone A	6,115.48	Close	6,223.53	Sliding sleeve door	Close	Isolated
Zone B	6,305.66	Close	6,320.69	Sliding sleeve door	Open	Producing
Zone C	6,410.04	Close	6,425.76	Landing Nipple	Close	Isolated

Table 5: Showing well completion profile with isolation depth for zone A & B

Pay Zone	Well annulus isolation		Payzone Isolation Device depth (ft)	Payzone Isolation Device		Well Status
	Packer Setting depth (ft)	Packer Status		Isolation Equipment type	Isolation Status	
Zone A	6,115.48	Close	6,223.53	Sliding sleeve door	Close	Isolated
Zone B	6,305.66	Close	6,320.69	Sliding sleeve door	Close	Isolated
Zone C	6,410.04	Close	6,425.76	Landing Nipple	Open	Producing

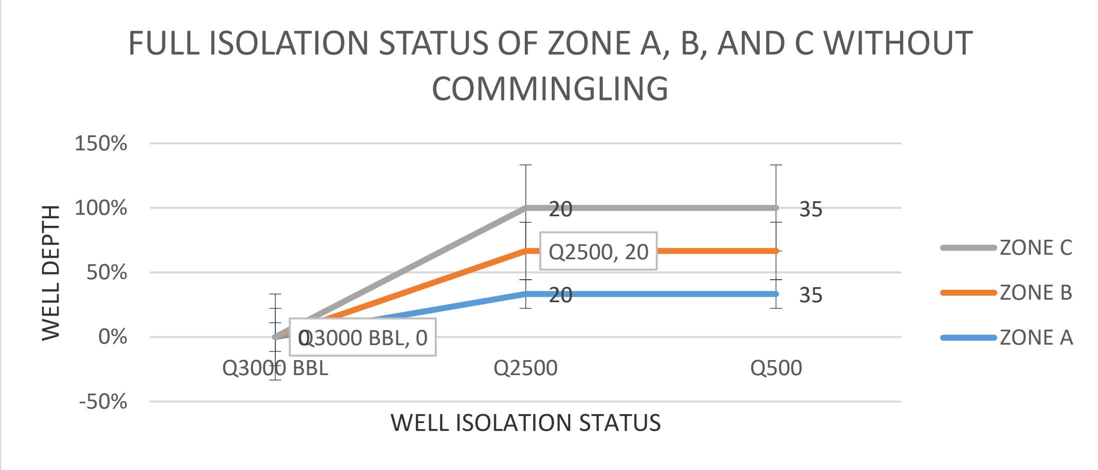

Figure 14: full isolation status of zone A, B, and C without commingling

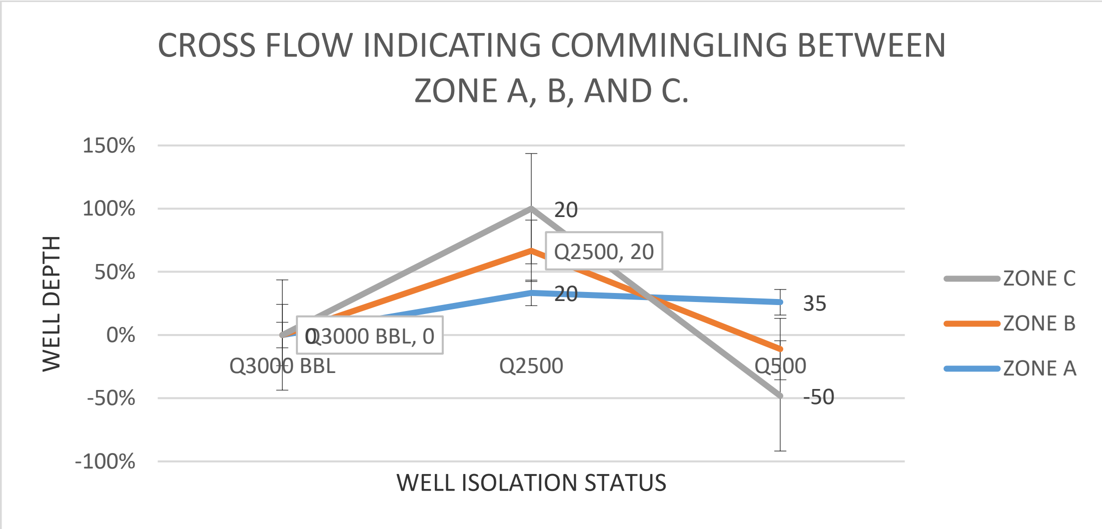

Figure 15: crossflow indicating commingling between zone A, B and C

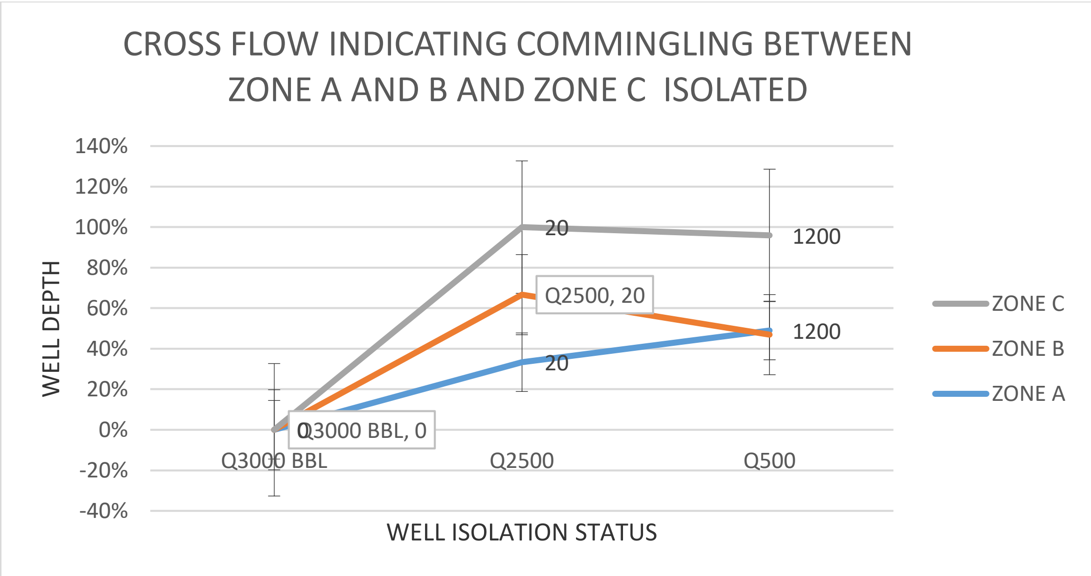

Figure 16: crossflow indicating commingling between zone A, B and C isolated

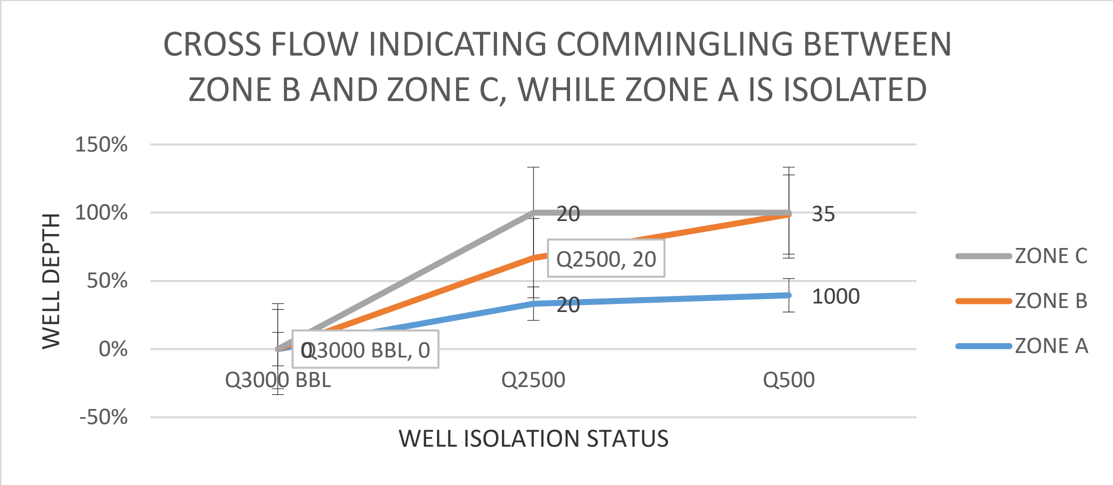

Figure 17: crossflow indicating commingling between zone B, C and A isolated

3.2 Data Analysis

The depth profile for production zone A's upper layer, which is 5 feet thick, is 6270 feet. The third Production zone C will be generated through the open hole at a depth of 6447 feet for the second Production zone B, which is located at 6340 feet with a 5 foot thickness. For each of the three zones, a Baker Model Hydraulic set Single String Packer Size 831-292 for 40-53.5lb/ft 9-5/8" CSG W/9.3lb/ft HCS Box x Pin was used. This packer's purpose is to stop produced well fluid from escaping from the annulus to the hanger and from mixing with fluid from other zones.

In order to stop well fluid from escaping from the annulus to the hanger and from mixing with fluid from other zones, Packer 1 was positioned at a height of 6115.48 feet above the first production zone.

To stop well fluid from migrating from the intermediate production zone to the upper and lower production zones, packer 2 was positioned at a depth of 6305.66 feet.

In order to stop well fluid from migrating from the bottom production zone to the intermediate and upper production zones, Packer 3 was positioned at a depth of 6410.04 feet.

Sliding Sleeve Door (SSD) was incorporated into the design to allow fluid flow or isolate a specific zone of interest as seen in the table above. A sliding sleeve door (SSD) slides open and close. It isolates the fluid from entering the production tubing as it shifts closer.

Sliding sleeve door (SSD) 1 was created and implanted at a depth of 6033.92 feet. While Sliding sleeve door (SSD) 3 was installed at 6320.69 feet, Sliding sleeve door (SSD) 2 was installed at 6223.53 feet.

For fluid flow, Sliding sleeve door (SSD) 1 was mounted above HS packer 1. Whereas Sliding sleeve door (SSD) 2 and 3 were placed to, respectively, permit and isolate well fluid from zones A and B.

A sensor that is put on the Sliding sleeve door (SSD), connected to flow lines, and ended at the surface of the Christmas tree will start the system of closure and open. A fluid that is pumped through a surface pumping device to commence an opening and closing pressure will be used to activate it. The sliding sleeve door (SSD) shifts open when the maximum opening pressure is met, allowing well fluid to enter the tubing. When the pressure is reduced to its lowest point and the maximum pressure is released, the SSD spring relaxes, letting the door to close and preventing well fluid from mixing with other fluids in the tubing.

According to Table 3. above, Landing Nipples (a) were installed at 6425.76 feet and (b) were installed at 6435 feet using OTIS 2.205" XN Nipple W/2-7/8" 6.5lb/ft EUE Box x Pins. By placing the nipples at this certain depth, well fluid from the open hole will be blocked off to prevent mixing. The innovative idea is to use flow lines to connect a flapper system to a blanking plug so that it can be opened or closed as needed by applying pressure from the surface. The flapper will open when a specific maximum pressure is reached and close when the pressure reaches 0 psi. So, the generation of well fluid from the zone of interest would be enabled by this process, which would prevent commingling from occurring in any of the zones.

3.3 Discussion of Findings

By installing a 1/2-inch flowline on the SSD from the surface and terminating it at a Christmas tree, pressure may be pumped into the SSD to open and close the door and the Flapper on the Landing Nipple, replacing the traditional technique of activating SSD via the use of wireline. The opening pressure was calculated to be 5000 psi, and the closing pressure to be 0 psi. A zero psi pressure will be activated to keep the SSD door closed while producing from the lower zone when a zone needs to be isolated to prevent mixing of fluid being generated from other pay zones in the well through the same tubing string also the opposite.

The Landing Nipple Flapper in Zone C and the SSD in Zone B will be kept closed with a pressure of 0 psi to provide isolation between the two zones and prevent commingling in order to produce from Zone A, a pressure of 5000 psi will be activated to keep the SSD open to allow fluid flow through.

The typical wireline blanking plug is replaced with the flapper that was installed on the Landing Nipple. The landing nipple's flapper was activated by pressure pushed from the surface thanks to the installation of a flowline. According to a straightforward calculation, the flapper will open at 5000 psi and close at 0 psi.

The flapper on the Landing Nipple will be opened when zone C is to be formed by activating 5000 psi from the surface through the flowline while the SSD in zones A and B are kept close. By taking this step, the production of just zone C will be permitted, preventing the mixing of other zones. In order to produce zone B, a pressure of 5000 psi will be applied through the flowline keeping the SSD in that zone open, while in zones A and C, a pressure of 0 psi will be applied to close the SSD and the flapper on the landing nipple keeping those zones isolated from production, resulting in only zone B being produced and preventing commingling.

4. Conclusion

In conclusion, the use of pressure flowline to open and close SSD and Landing Nipple Flapper for isolating different zones in an intelligent well completion of multiple zones so as to prevent commingling was effectively designed using visio software.

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