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Dual Well Completions String Deployment Time and Cost Optimization for a Typical Niger-delta Field

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Abstract Dual well Completions principally involves preparing and running in tubing and its associated down hole jewelries as well as perforating and stimulating the well as required to produce hydrocarbon. completions engineers maximize the recovery mechanism and profit potentials of a well so as to satisfy business expectations of the investors and stakeholders of the well. We achieve this by installing the most efficient and cost effective completion jewelries in the well. This thesis focuses on dual well completions design optimizations whereby a smart well completion packer activation system was designed using a novel pressure sensitive modified hydro-trip nipple sub. A combination of hydro trip sub and landing nipple profile with an attached flapper element designed to open at 5000 psi rating and closes at 0psi rating, remotely operated from the surface to create smart well isolation and packer actuation process requiring less operating time and completions cost. An alternative use of ball seat, a sharable brass screws and pins as against the conventional use of steel shear pins in the design of hydro-trip pressure sub for hydrostatic packer activation was achieved. Results obtained shows that brass shear pin were more operationally friendly, requires less shear pressure, less time required for activation, saves operational time and cost. The attachment of pressure sensitive flapper created a fail safe alternative means of Hydrostatic S packer actuation and zonal well isolation; which reduced operational man-hour as well as completions cost.

Keywords Dual Well Completions, Completions String, Cost Optimization, Time Optimization.

1. Introduction

Dual well Completions is the interface between the two or more reservoirs and surface manufacturing. A completion designer's job is to take a drilled well and turn it into a reliable conduit for production or injection [Bellarby, 2009]. In order to do this, the bottom of the hole must be prepared according to the necessary requirements, the tubing and its accompanying down-hole jewelry must be run in, and the well must be perforated and stimulated as needed.

As a well completion design engineer, it's pertinent to maximize the recovery mechanism and profit potentials of a well so as to satisfy benefit expectations of the investors and stakeholders of the well. To achieve this, we are interested in producing the most valuable resources from the well which is oil and gas by installing the most efficient and cost effective completion jewelries in the well.

Proper equipment selection and to guarantee the well can flow effectively given the reservoir conditions and to allow for any activities considered essential for improving production and safety, this "completion string" must be designed carefully. The most typical dual string completions occur in stacked reservoir sequences within most of the Niger-Delta oil field. The choice of running dual strings, completed in tandem it might have variety of reasons: contrasting fluids; a case where the various sands in question have different pressure regimes capable of creating severe cross-flow when being commingled. Reserves assurance; a case where one interval would subdue production from another when it waters out. In consideration of the requirements by the regulatory authorities such as tax consideration at different production zones and depth. Injection of fluids in a multipurpose well in combination with the production from another.

Optimizing well completions means moderating the economic parameters of the well design configuration such that its overhead cost would not have negative effect in the financial returns on the investors expectation and the expectation of the various stake holders involved, either in the short run or in the long run, but also not undermining safety and quality considerations. With these facts in mind, it is worthy to note that a field's development's overall economic life, completions play a significant role. Considering completion optimization string design, some of the basic questions to ponder about may include; would the production rate be sustained over time, what would be the value of accelerated oil after OPEX and tax, what would the total capital cost of installing a 13cr smart well pressure sensitive well completion components be as against other material consideration. What would be the cost and effect of running a dual completion string as against running a single string alternate completion for the same well with the same number of reservoir sands. what would be the cost and effect of running a completion with the deployment of wire-line for packer setting as against using components not requiring wire-line operation. what would be the cost of future workover over time due to failures caused by wireline string parting in hole, failure of hydro-trip pressure subs during packer actuation, premature shearing of the pressure subs shear screws and other related operational issues? What impact would be felt if a given completion fails? What discount factor is one putting into consideration in terms of a chosen design over the other especially looking at failure criteria and its alternatives? In essence it is optimum to design a smart well completion for cost effective smart well isolation system, smart packer activation system, cost effective tubing replacements, and reduction in the number of complex material involved in completing the well.

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2. Materials and Methods

The major materials in consideration for this course work are:

i. Hydro-trip pressure sub
ii. Hydro-trip Nipple sub
iii. Landing nipple
iv. Safety valve (SCSSV)
v. Hydraulically set / hydrostatic set packers
vi. Brass and Steel shear pins

2.1 Tally preparation and tubing make-up process

Tubing was laid in one rack since all the pay zones were completed with the same strings of 3-1/2 tubing with exception of some special accessories deployed by wireline companies. All the tubing were assigned joint numbers serially with their respective tally length in feet. The tubing were properly drifted, dimensioned and the thread connections kept under running condition. To minimize stick out while running in hole pup joints of various sizes were deployed on tally and painted green on the tally to recognize need to swap while running in hole. Swapping minimizes number of Pup joints during running in hole. This was achievable because the strings were of the same size and grade. The 3-1/2 HCS tubing L-80 with 13%Cr used was extremely delicate when compared with conventional HCS. In order to aid make up both Pin and Box were doped lightly with API-Modified dope to assist with lubrication and friction factor while making up. Excessive dope were guarded against to prevent particle gathering on critical I.D on string and fluid contamination. Pup joints were guided to dual packer using hand in series, last one with sufficient clearance for tong engagement was torqued bearing in mind that torque will be transmitted laterally to achieve optimum on the joints to the packer. Pin was guided to box by simultaneous engagement by stabber and chain tong till engagement of last thread before engaging tong to achieve optimum. Both threads and connections were cleaned with degreasing solvent. Subassemblies were made up to immediate succeeding tubing in mouse hole before actual commencement of running in hole.

2.2 Hanger subassemblies deployment

Hanger subassembly dummy run on Tubing Head Spool to verify conformity of the dimensions before the actual run. Pin to Pin joints were used below hanger to create room for sufficient clearance while running.

2.3 Safety valve deployment

Safety valve control line was pressured to addition of tubing pressure plus 1.5 of safety valve opening pressure to guard against sudden flapper closure while setting packer to near its maximum pressure. Inflow test was carried out on safety valve, since packer was set using plug and prong, flapper was closed, pressure bled down to 200psi and check if there will be pressure transmission above flapper.

After making up the safety valve, the control line was swaged on the safety valve port. Thereafter the NPT adaptor was connected to the safety line port and was flushed to get rid of debris and entrapped air from the line. The process was repeated three times to completely flush the flow line from entrapped air and debris on the flow line and the port of the port of the safety valve. The safety line was connected to the safety valve port and was firmly tightened. The lines were pumped with ENERPAC pressure pump to open the safety valve flapper. The three valves of the testing flow line connected from the ENERPAC pressure pump to the safety valve were then closed to prevent flow back of pressure from the safety valve. The line was then bled off from the ENERPAC pressure pump. The test fluid 'the line oil' was collected from the manifold valves in a graduated cylinder calibrated in 'ML' milliliter. The volume was observed and it read, 20ml. The process was repeated three times and the results gotten showed consistency of 20ml consecutively. After the third process, the valve was bled off and then pumped to open the flapper of the safety valve at 5000 psi maximum. The line was connected to a pressure gauge which showed a signature indicating the trend of movement of the safety valve ability to hold pressure without failure or leakage. The gauge was monitored first for 15 minutes.

After the 15 minutes wait, the valve was bled off, volume of the oil was also checked on the graduated cylinder to ensure there is no drop in the oil volume. Then we deviated from the norm by testing for 45 minutes and 1 hour respectively. This was done to monitor the safety valve performance for a longer time against minor seepages due to system error, temperature change and expansion or contraction factors in the system over a long period of time. The idea is built on the basis that if the system could hold pressure consistently for 45 minutes and 1 hour respectively, it means it could sustain any subsurface condition throughout the life time of the well if all factors and condition remains the same. As the 45 minutes and 1 hour was reached, the gauge was observed to ensure it maintained consistency at 5000 psi. with no pressure drop, it was a confirmation that there was no leakage in the safety valve and the flow line, which also confirmed that the safety valve will be able to maintain consistency throughout the life time of the well. After confirming the test results, the reel of control line was rolled out gradually as more tubing strings were made up to space out the safety valve. The flow lines were strapped or clamped against the body of each tubing close to the box end to hold the flow line from dangling. More tubing joints of about 120 to 150 feet was made up after the safety valve to enable the safety valve move down to its safe working depth. When the desired safe working depth of the safety valve has been achieved, roll out more flow lines and use it to wrap about fifteen times around the upper most tubing closed to the tubing hanger to create excess coiled length of the flow line in the case of stretch and termination at the well head and XMAS tree. The excess safety line should be wrapped on the pup joint closed to the hanger. Thereafter the flow line was terminated at the tubing hanger ports by swaging the Feruse fitting to the control line and then connecting it to the NPT adaptor attached to the hanger port. There are fitting through and non-fit through hanger port. For a case of non-fit through hanger, the safety line would be connected to top of the hanger and then initiate pumping of the flow line with ENERPAC pressure pump to keep the safety valve flapper open. The line was not cut yet, the landing joints was carefully made up to the top of the tubing hanger and the entire completions string was carefully lowered down to the tubing spool to complete landing of the string.

2.4 Spacing out process

Up and down weight was checked before commencement of space out operation, by instructing the driller to slack off weight. When the driller completely slacked off, the weight shown on the martin decker gauge was determined, it was noted as the down weight.

Again the driller was instructed to pick up weight, when he picked up weight, the value of weight shown on the martin decker gauge was recorded as the up weight.

The reasons for determining and recording the up and down weight is is to enable the completions engineer to know the weight of the string when the string is lowered down further with additional tubing joints to tag the actual bottom of the well.

2.5 Tagging of the completions string

The bottom of the well was tagged having known the true depth of the well at the end of assembly and the height of the elevation. To carry out tagging, more tubing was added to get to the bottom of the well. When the tubing reached the bottom, measurement was taken with steel rule 5ft as some few joints of the well string is pulled back upward to surface to determine the difference from the end of assembly to the bottom floor of the well. This gave indication of the true depth of the well bottom. After determining the true depth of the well bottom, the additional tubing string that was initially made up was pulled out and laid down serially while pup joints of calculated length were made up to complete the length that constitute the true depth of the well. About 5ft gap is usually given from the well bottom to prevent sand and well debris from blocking the tubing opening. After this, the elevation was subtracted from the depth and this was operation concludes the well completions tagging and space out.

After the make-up of landing nipple on top tubing hanger, the well string was landed. It was noted that before the make-up of the tubing hanger, the well was first displaced to packer fluid using pumping unit before the completions string was finally landed.

2.6 Packer sub assembly run-in-hole

After landing the well, wireline went in with plug and prong to locate and plug off the XN nipple. When the wireline came out to the surface, the pumping team started pumping pressure through the completion string to a given packer setting pressure gradually until the packer completely packed off. As soon as the packer was set, the completions string was tested from the back side and also pulled from the draw test, a process called 'the pulled test', to determine if the packer is completely packed off. If the strings pull along, it will an indication that it wasn't completely packed of which means that the well will leak from the annulus during production and the string will also not be secured. But if it refused to pull along upward, this showed the well completions string is fully packed off and the well secured from leakage.

Once packer was confirmed fully packed off, the BOP was nippled down and the XMAS tree was nippled up. The safety valve flow line was then terminated on the XMAS tree. The safety valve was pumped open to allow the well fluid be put on stream and start producing. The Back pressure valve which was initially installed as a secondary pressure control barrier was retrieved through rig floor by making up joints to it and rotating it anticlockwise until it disengages from the hanger.

2.7 Hydrostatic packer setting process.

At 1950 o'clock, the pumping team started pumping for the testing the, the pump rate was 2.7 bbls /mins the pressure of the pump built to 3000 psi gradually. The surface line was first tested. For 10 minutes, at 1000 psi, and 3000 psi. It held pressure consistently without leakage. This shows there were no pressure leakage from the as observe through the gauge and the rig floor. The surface line was bled off to zero psi after the testing for 10 minutes and it showed that there was no leakage.

Then the actual packer testing started at 20.0 0'clock. 500psi was initially introduced, after about 5 minutes of waiting and observation it was gradually increased to 3000 psi. the gauges showed flickering signs when it approached 1800 psi which was the initial packer setting pressure. This shows that at 1800 psi, the shear pins have started sharing, and the packing element disengaged open to seal off the casing annulus by expanding in size. After reaching the 3000 psi rating for maximum setting pressure, the pressure was maintained for an additional 15 minutes to ensure the packer was completely packed off.

2.8 Testing of the packer back side.

The well head valves were lined up to connect to the pumping unit. Then the other opposite valve at the wellhead was opened to equalize he pressure differential while pumping. When pumping to test the backside, the pressure builds up gradually and vents off through the open valve. Before testing the back side, it was ensuring that wireline goes down to equalize pressure below with the pressure above in the tubing string.

The test for the packer backside started at 12.00 o'clock. The two valves at the well head was opened. One was connected to the unit, the other had a little opening which allows water to flow out. At first, dirty water and grease like debris flowed out of the annulus valve. As the pumping continued gradually, the annulus got filled, which enabled it to allow trapped air to vent off after which only clear water started flowing out. As the pressure becomes high flowing and flowed consistently for a period of time, the pump was stopped and the valve at the right side was closed leaving only the one connected to the pump line to be open. Then the pump is started again and pressure is gradually built up to 1000psi. when it reached 1000psi, the pump was stopped and held for 15 minutes to monitor if there would be any pressure drop. After 15 minutes had pass and there was no noticeable pressure drop in the gauge, as the pressure level was still maintained at 1000 psi, this showed indication that the packer was not leaking. The 15 minutes' test started at 1480 o'clock and stopped at 207 o'clock. When the 15 minutes' test was completed, the pumping team bleed off the pressure and the rig floor was notified to check for any leak on the string. There after wire line was rigged down.

2.9 The initial preparation before run in hole:

The HS packer was made up with 10ft pup joint at the top end and 6ft pup at the bottom. The packer and sealing element were re-examined to ensure that its integrity is still intact. The threads were also quality checked and certified fit for purpose.

2.10 Pressure testing of packer with charts recorder:

The packer was pressure tested at the test bay. Water was use as the base fluid for the test and the packer entire I.D was completely fill up, test cap was installed to both top and bottom of the two ends of the parker connection.

i. The packer was first tested to 500 psi with charts obtain, no leakage, the pressure was raised to 4000 psi, there was leakage at the test cap connection at the bottom end of the packer.
ii. The test cap was loosed, and retightened. Then the test was repeated at 500 PSI, 4000 PSI and 4500 PSI, there were no leakage this time.
iii. The charts were observed by both SNEPCO REP and Halliburton Completions Engineers and was certified okay, stamped and signed off.
iv. The water was evacuated from the packer and brought out from the test bay to the workshop for body maintenance and vacuum venting**.**

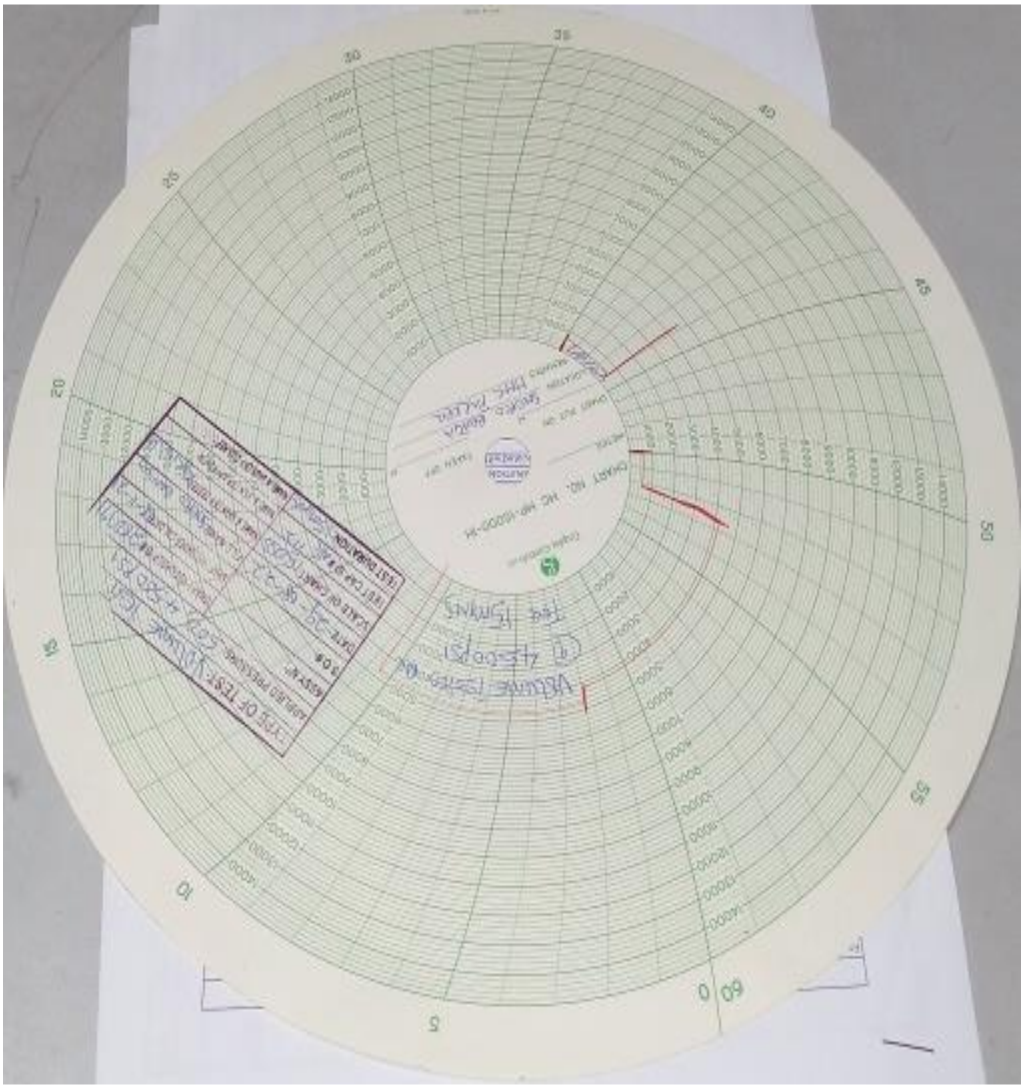

Figure. 1 The Packer Was Tested at 500 Psi for 5 Minutes, 4000 Psi for 15 Minutes and Finally for 4500 Psi for 15 Minutes as Indicated On the Chart Above

2.11 Examination of packer:

The Completions Engineers carried out a critical examination of the packer elements to ascertain its functionality and fitness for use. The key areas examined was the packer setting slips, the packer elastomeric packing elements, the shear pins, the vacuum nuts and the general body condition. After the thorough examination the team confirmed that packer was fit for purpose and certified it okay

2.12 Identification of connection type, size and weight:

The examination of the connections was carried out this check carried was able to ascertain the various connection of the sub assembly components to be used in other to make cross over subs to fit all connection joints together during the installation process.

This action is necessary because, without properly identifying the thread connection type properly, to know the interchangeable connections, the installation process may encounter glitches caused by ranging from thread galling, cross threading, parting of string in the well, leakages and son on. This may warrant serious non-conformance issues resulting to more man-hours spent operationally, which will thereby lead to losses in financial and operational cost. For example, when the HS packer assemblies were checked it was observed that the following non interchange connections in terms of size and thread were found.

1). 6-5/8'' 25CR L80 TSH BLUE PIN at the bottom c/w: 6-5/8'' 24PPF 13CR L80 transition joints of about 15ft + RPT Nipple + 6-5/8'' 24PPF 13CR L80 transition joint of about 12ft.

2). A 5-1/2'' JFE Bear x 6-5/8'' 24PPF 25CR TSH BLUE BOX cross over Sub at the top end c/w: about 20ft transition joint with connection 6-5/8'' 24ppf 13cr L80 TSH BLUE box.

After the examination, the Completions Engineering team looking at the shelf life of the packer, advised that it will not be nice to break off the existing connection as any attempt to carry out the breaking and remaking operation may gall the thread which will permanently damage the packer. They advised that a new 6-5/8'' x 5-1/2'' cross-over be manufactured to be made on the top and bottom of the existing packer assembly so as to correspond with the connection of the entire completion string.

2.13 Inspection examination of connection to ensure fitness:

The Quality team thereafter inspected the connection, a minor corrosion was observed at the pin thread, this was repaired as it was within acceptable tolerance level.

2.14 Vacuum preparation:

After evacuating the water used for the packer testing, A Team of Engineers came and performed Vacuum operation to vent off the entrapped air and water from the packer so as to enable the packer element to actuate during packer deployment and setting.

2.15 Surface body preparation:

The transition joints were buffed to remove scales and rust, after which anti-rust chemical was applied to protect the external body of the transition joints from corrosion.

Figure 2: Buffing was carried out to remove minor scales and rust from the transition pup joints on the packer assembly.

2.16 lamiflex protection:

The entire packer body was protected with lamiflex to prevent damage to, slips, elastomers and other sensitive elements of the packer before loading out. At the rig site the lamiflex and other protective element worn on the packer was removed, packer re-examined before rigging it up to the rig floor.

Figure 3 The packer elements and main body was wrapped with lamiflex to protect the sensitive elements

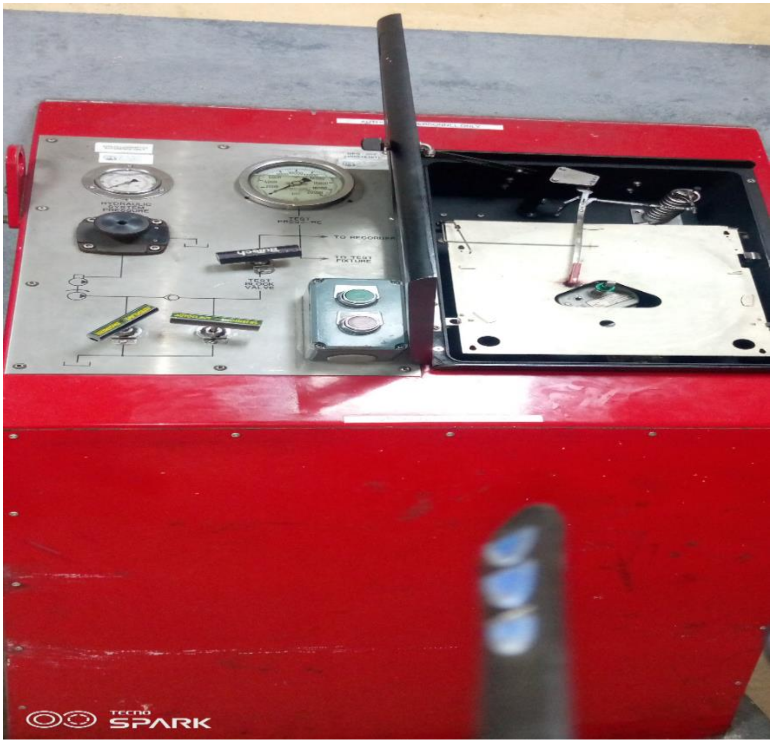

Figure 4 Pressure test chart recording unit.

2.17 Research Design

i. Troubleshooting scssv and trsv failure mode:
- Pressurize to 5000psi, wait 5minutes – volume of fluid=20ml
- Pressurize to 5000psi, wait 15minutes –volume of fluid=20ml
- Pressurize to 5000psi, wait 45minutes –volume of fluid= 17ml
- Pressurize to 5000psi, wait 60minutes – volume of fluid=15ml

ii. Testing hydrotrip nipple sub, c/w pressure sensitive flapper
- Pressurize to 500 psi
- Increase gradually to a pressure of 1000psi,
- Continue to add 500psi incrementally up to 5000psi
- At 1200 psi initial opening of flapper will begin,
- At 5000psi full opening was achieve
- Bleed off to zero (0 psi) to closed up flapper against nipple profile, spring fully retracted enabling sealing of the well string.

iii. Shear pin and packer setting
- Pressurize to 500psi incrementally
- At 1800psi slips and packing element begins activation
- At 2500psi packer fully activated
- At 2950psi brass shear screws completely shear off allowing ball seat and ball to drop to the bottom
- At 3950psi steel shear screws completely shear off allowing ball seat and ball to drop to the well bottom.

2.18 Hydro-trip pressure sub coupled with nipple no-go

Hydro-trip pressure sub which has a conventional ball size of 2-1/2'' and 2-3/4'' for a 3-1/2'' was deployed in the well. The sub was designed to activate using 10 shear screws; each shear screws are rated base on the type of material used. There are two basic materials that was experimented in the course of this research; the brass shear screws and the metal shear screws.

The brass shear screws are rated at a shear value of 290 psi per screw with a tolerance value of ±15%. The brass shear screws have a maximum shear value of 2900 psi for the ten screws to fully activate with when pressured to set the packer with a tolerance rate of ±15%.

This means that, if one shear pin requires 290psi to shear out and you have a total number of 10 shear screws, the calculation would be:

10 shear screws x 290 psi = 2900 psi maximum

On the other hand, the steel shear screws were having a ball size of 2-1/2'' and 2-3/4''respectively. The ball seat dimension before shifting is 2.312'' and 2.500'' respectively. The ball seat ID after shifting after shifting was 2.718 and 2.953 for both the 2-1/2'' and 2-3/4'' ball sizes respectively. The minimum shear value of the steel shear pins is: ±15% of 395 psi, while the maximum shear out value of 10 steel shear screws required to activate a packer setting element is 3950 psi. The landing nipple has a seal bore, internal profile and a NO-GO profile which often varies with respect to its positioning depending on the configuration designed by the original equipment manufacturer (OEM), this however makes the locking devices of the landing nipples non-interchangeable. In practice, the main reasons for the NO-GO profile incorporated on the landing nipple is for positive depth control, for testing of pressures from the top by initiating some kind of downward force through the NO-GO profile of the landing nipple, however, using this novel designed for both hydro-trip system and plugging of string for testing in one device makes the old practice of using hydro-trip and landing nipple separately useless. The No-Go profile of the landing nipple reduces downward. This reduction in size creates a kind of restriction for tools that may be subsequently run through the upper completion down to the lower completion to achieve isolation of each zones or to achieve a positive depth control as the case may be. The nominal profiles sizes with no-go is within the ranges of 0.06 inches' clearance larger than the hydro-trip ball seat. For this reason, we will be considering designing this device such that the hydro-trip ball seat would come below while the landing nipple profile is positioned a little distance above the ball seat so as not to be affected by the restriction caused by the no-go and an attached flapper that would close in to serve as a blank off device for secondary isolation in case the ball seat prematurely set before full activation of the HS packer packing element.

Another consideration is the fact that sometimes the pressure sub shear screws balls may not completely shear out thereby creating protrusion which would in turn create restriction to the blanking plugs if positioned at the top before the no-go profile. But with the hydro-trip sub seat positioned at the bottom of the landing nipple no-go profiles, there would be no chances of an improperly shear screws protruding outward to restrict the installation of plugs down the strings. And by the creation of flapper sensitive device to close up the nipple sub, wireline operation would be completely eliminated making the use of blanking plug irrelevant.

This therefore solves the problem of failures due to shear pins extrusion in the string, eliminates the challenges usually faced having wireline run down the string to retrieve or dress-up the extruding shear pins which most times result in having a fish lodged inside the hole due to wireline strings parting in the hole during operation. It saves millions of dollars for the company by preventing the possibility of pulling the string out to change the hydro-trip pressure sub if the problem of improper shearing of pins occurs and finally also save the company substantial man hour that would have been spent in running both the landing nipple and hydro-trip pressure sub as a separate tool, thereby resulting in cost saving and ensures to keeping the completions design simple, smart and safe to operate.

2.19 Deployment methodology using a pressure sensitive flapper activation

This course work contains well design configured to optimize dual completions string run in hole with the aim of activating HS packers whose activation system would be based on 100% pressure sensitivity. The novel concept is about a tool that combines the use of hydraulic flow line with hydro-trip pressure ball seat and a nipple profile configuration mentioned in chapter 3.2.1 above. At the upper segment which contains the landing nipple, it has a ball seat with shear screws attached. The shear screws allow the ball seat to shear off and drop down to the bottom of the well during packer activation. This works with a given pressure rating, the pressure rating of the sub shear pin must be greater than the packer setting pressure. In this study, the packer initial and final setting pressure is rated at 1800 Psi and 2500 psi respectively, while the shear pressure of the hydro trip pressure sub is 250 psi x 10 shear pins which equals 2900 for brass shear screws and 395psi x 10 shear pins which equals 3950 for steel. See picture of shear crews in figure 3.5 and 3.6 below.

Considering the flapper activation design, a pressure sensitive system was attached to a ported orifice on the pressure sub with an XN no-go profile. The flapper works on full open and full close mechanism when activated. It requires a pressure of about 5000 psi to be fully open and zero (0 psi) to be fully closed. A return spring was attached to the hinges which enables it to close back when the pressure in the system is removed. The pressure sub has a ported orifice where a flow line would be attached. The hydraulic flow line is made of stainless chrome material of size ½’’ and ¾’’. The flow line is connected to the pressure sub from the surface and terminated on the hanger and linked to the well head to enable the pumping of pressure when the need to open the flapper arises or vent off the pressure when the need to close the flapper arise. The flapper slides upward to allow full opening and downward to allow full closing. This component will be mounted in the well completions string as an integral part of the completions tubing with about 6ft to 10ft space out pup below a hydraulically set parker as a means of supplying the pressure required to activate the packer setting mechanism. This novel initiative provides two alternative methods of setting the HS packer, first alternative would be the use of hydro-tripping ball; while the second alternative would be the use of the pressure sensitive flapper.

Figure 5: Sample of steel shear screws for smart well completions pressure sensitive hydro tip nipple sub

Figure 6: Sample of brass shear screws for smart well completions pressure sensitive hydro tip nipple sub

Figure 7: Sample of brass shear pin for smart well completions pressure sensitive hydro tip nipple sub

2.20 Hydro-tripping

For the hydro-tripping ball, it involves pressuring the tripping ball slowly in a chase process via the packer internal profile down to the hydro-tripping ball seat. As the ball lands on the ball seat element, the pressure build up begins to rise and once sufficient pressure is applied above the shear pin rating of the packer, the brass shear pin shears allowing the packer setting mechanism, 'the slips and the sealing elastomer' will be automatically activated. As more pressure is continuously applied, the shear pin of the hydro-trip pressure sub will also shear forcing the ball down to the bottom of the well thereby leaving the internal diameter of the hydro-trip pressure sub in a full open position which will make the sub to be having the same internal diameter with the tubing internal diameter. **The start time for the pressure initialization was noted and the end time was also being noted**. This time would be used to determine average running time per well while making use of the hydro-tripping nipple sub as against using Wireline or slick-line operated system.

2.21 Flapper sensitive setting operation:

Alternatively, a flapper sensitive ball has also been integrated in the sub. In case of failure of the hydro-trip pressure nipple sub to fully set the packer due to premature shearing of the pin or inability of the shear screws to shear out, the flapper system could provide immediate alternative of setting the packer without requesting for wireline run. While running the hydro-tripping sub, the flapper was kept full open by applying pressure of 5000psi through the hydraulic flow line tied to the surface equipment. This time, the 5000psi pressure has to be bled off down to O-psi (zero psi) to enable the flapper close in. This will shut of communication between the pressure below and the pressure coming from the surface facility. As the flapper closes in, the pressure pumping unit will be activated, the time for the start of the operation was noted. The pressure builds up gradually from 500 psi, 1200 psi, 1800 psi after which the packer slips and elastomers started activating. The pumping to allow pressure build up continued up to 250 psi and 3000 psi respectively to ensure full activation of the packer elements. After the packer setting, leakage and pull or anchorage test was conducted at the backside of the packer via the annulus and through the drillers console by applying an upward pull to the well completion string from the rig floor and observing the martin decker gauge to ensure that there is no leakage from the element and that there is proper anchorage of the well string to keep the well string stable and prevent floatation of the well string during production. After both test had been completed, the flapper was reopened by pumping a 500psi pressure to keep the well permanently open while the well is landed and put on production stream. The finishing time for this operation was noted and was used to calculate the total man-hour spent in using this well string packer activation method.

Figure 8: Sample of smart well completions pressure sensitive hydro tip nipple sub

Figure 9: Sample of pressure setting ball

Table 1: Well a completion optimization log

S/N	Mat. Deployed	Deployment Time	Cost Factor @ $50000/D
1	TUBING	45 HRS	93750
2	HYDROTRIP NIPPLE SUB RUN	3HRS	6249.99
3	BALL CHASE AND SEAT SHEAR	7 HRS	14583.31
4	SCSSV RUN	8 HRS	16666.64
5	SPACE OUT	6 HRS	12499.98
6	LANDING	6 HRS	12499.98

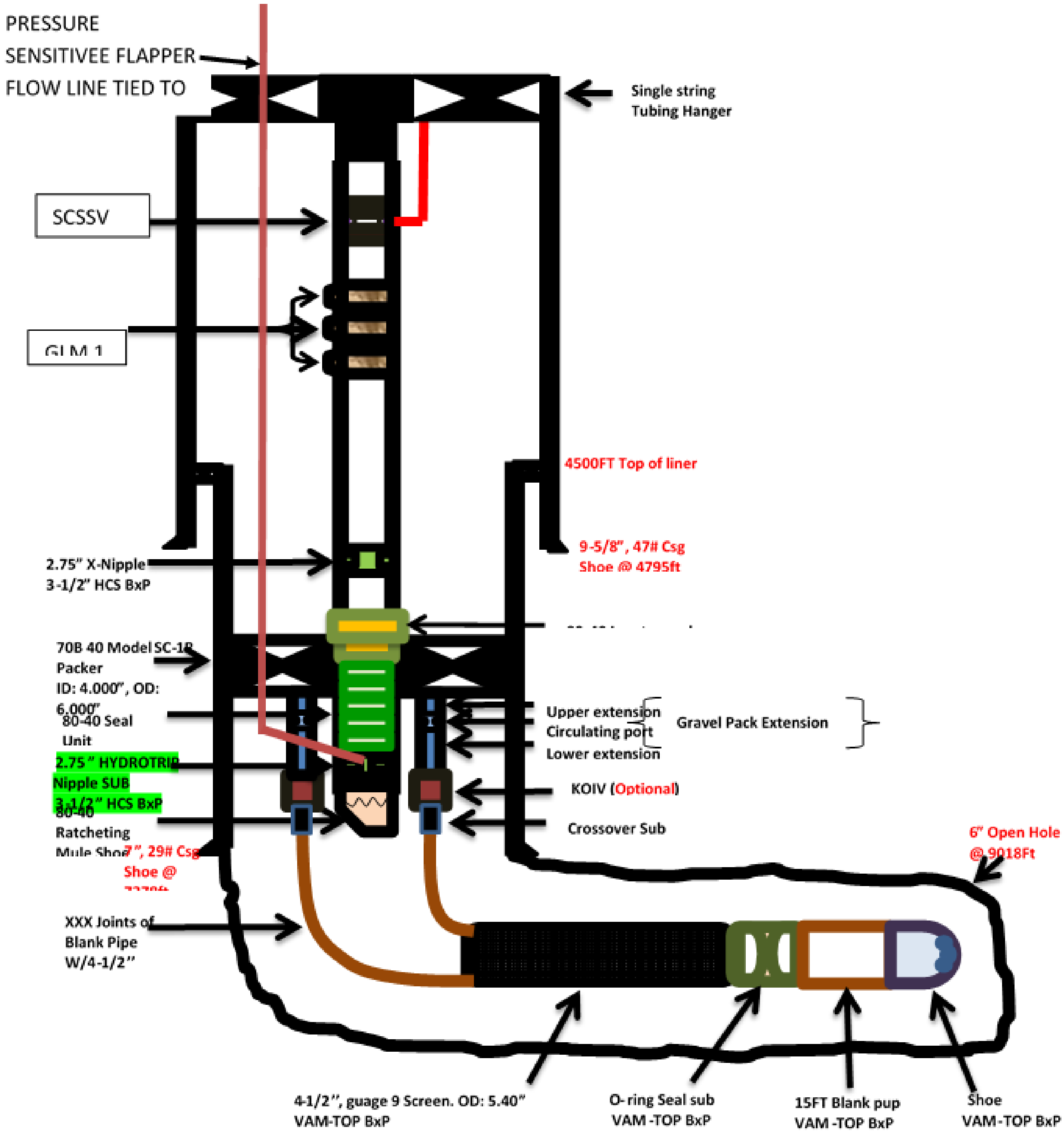

Figure 10: Well schematics with hydrotrip nipple installed

2.22 Using a wireline operated landing nipple

The second scenario involves a single string alternate design wherein a landing nipple and XN nipple were independently installed on the well completion string and mounted below a hydrostatic set packer with about 6ft to 10ft pup joint space out.

In this scenario, we are using the XN nipple as case study. After running down the blanking plug to seat at the XN nipple profile, pull the wireline up back to surface, then pick up the prong and run in again to stab the prong into the blanking plug. The reason is to allow the prong to seal off the self-equalizing port of the blanking plug to avoid pressure leakage. After the prong is properly stabbed-in to the plug, the wireline is pulled up back to surface to allow the pressure pumping unit to pump in pressure by applying the same steps of pumping slowly until the pressure in the tubing reaches equalization then the pressure is increased to reach the packer setting and then additional pressure of 500 psi will be added to the initial packer setting pressure of 2500 psi thereby increasing the pressure to 3000psi. this is to ensure that the packer is fully packed-off. Then the packer back side would be tested. If parker is completely set the packer wireline will need to go in to retrieve the prong and then do a second run to retrieve the prong. The starting time and ending time were noted. Thereafter, a plot of average lost time per well were drawn to determine the cost implication of using this wire-line blank plug activation method over the choice of using hydro-trip pressure sub and the use of flapper sensitive pressure sub without wire-line operation.

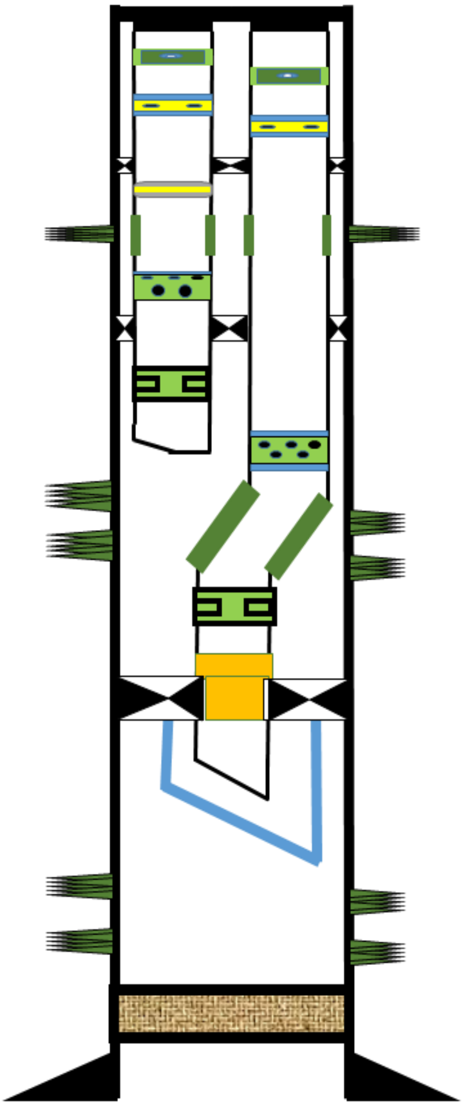

Figure 11: Initial completions three zones schematics c/w dual string method

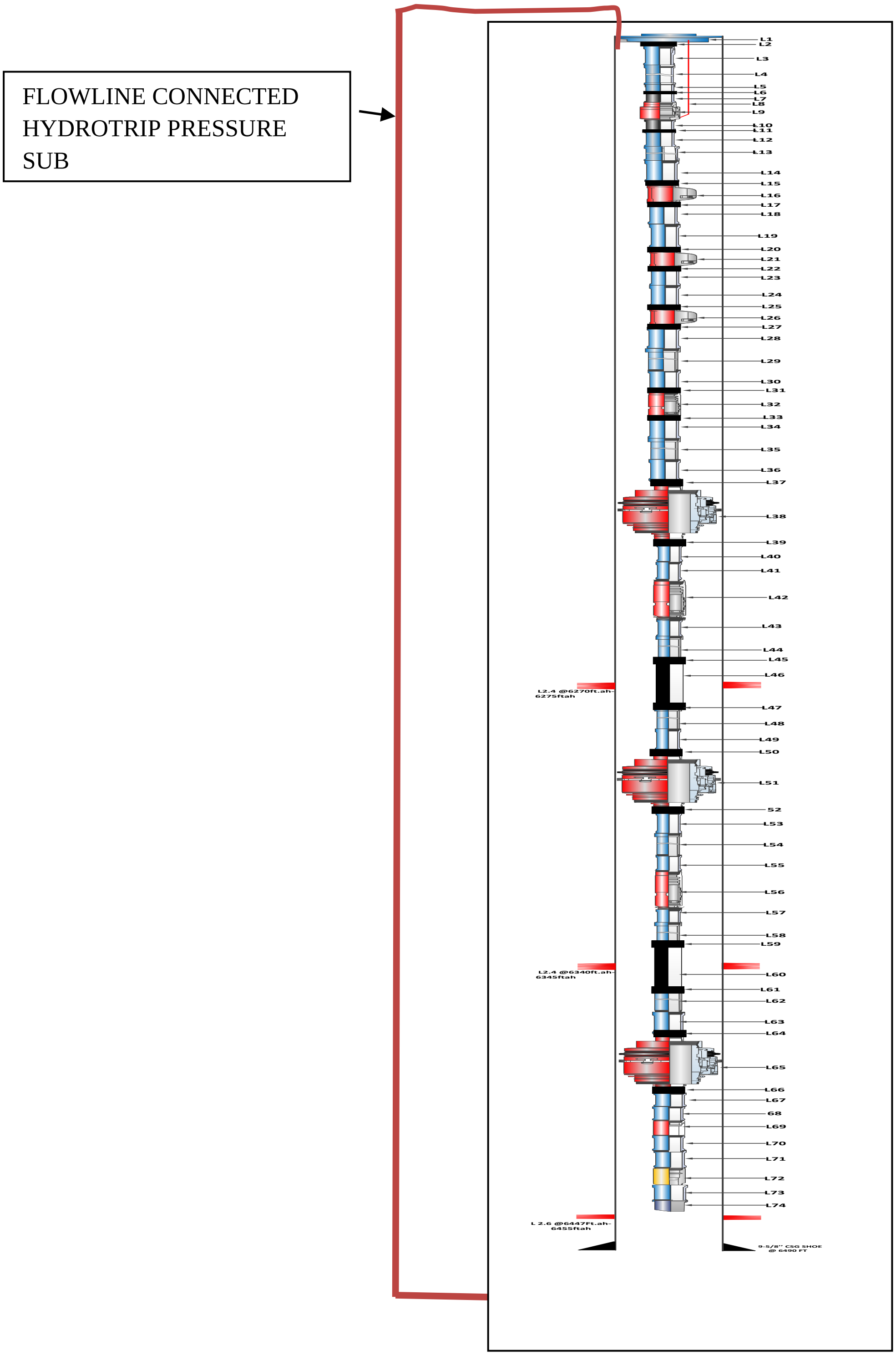

Figure 12: Three zones schematics c/w single string alternate method

3. Results and Discussions

3.1. Discussion on the Hydro-trip Nipple Sub Design

The Hydro-trip nipple sub was design to the nominal size of 3-1/2’’ Outer diameter (OD), the internal diameter was turned down to a size of 2.953’’ with a drift ID of 2.867’’. The ball size was turned down to 2-1/2’’, the ball seat that would accommodate the ball during parker setting was turned down to a size of 2.500’’, the ball seat was design to open up to a size of 2.953’’. The estimated value of each of the shear screws is 290 psi per screw, with an allowance of plus or minus ± 15%. Base on this design criteria, there are 10 brass shear pins evenly inserted on the body of hydro-trip nipple sub to hold the ball seat in place. By calculation, since one brass pin requires 290 psi to completely shear out, it means that the maximum shear value required to completely shear out the ball seat from its position would

290 psi x 10 brass shear pin = 2900 psi.

The choice of material selected for the shear screw was brass. This is because brass shear screws have a better tendency to completely shear within the specified pressure rating without failure, it also has the advantage of not leaving any piece protruding out at the eyes of the sub’s ID after shearing, this completely eliminates the problem of having to deploy wireline for mechanical shearing of any possible extruding ends of the shear screw due to improper shearing, which would have resulted to delay and NPT that would amount to negative cost effect for wireline to round trip in and out of the well with wire line retrieval tool to initiate mechanical shearing of the shear screws, thereby saving the company a substantial amount of dollar and reducing the operating cost required to complete the project.

On the other hand, when you consider a design of the hydro-trip nipple sub using steel shear screw, the shearing pressure per screw is 395 psi. Base on this design criteria, there are 10 steel shear pins evenly inserted on the body of the hydro-trip pressure sub to hold down the ball seat in place. By calculation, since one steel pin requires 395 psi to completely shear out, it means that the maximum shear value required to completely shear out the ball seat from its position would be

395 psi x 10 brass shear pin = 3950 psi.

In comparison of the two method of using brass shear pin against steel shear pin, it is observed that the steel shear pins require more pressure of about 105 psi greater than the brass shear pins pressure. This means that the greater shear force, which requires more time to shear, hence translating to higher operating cost for the company and thereby considered not economically and technically viable for a safe a cost effective system. Another observation on the disadvantages of using steel shear screws is that it most times doesn’t shear completely thereby resulting to call up of wireline unit for the deployment of wireline tools to mechanically shear off the un-sheared steel shear screws. Again wireline deployment for this mechanical shearing would amount to additional operating time which further translates to higher operating cost.

With these design, when pressure is exerted, the hydro-trip sub shear screws, shears to allow the ball seat open fully thereby allowing the internal diameter of the ball seat area widens up to form the same size as the internal diameter of the 3-1/2’’ pipe used for spacing out the well string. On this note the pressure setting ball and the ball seat drops to the bottom of the well and subsequently lost into the reservoir formation. Hence there would be no operating time lost for setting ball retrieval, this means that the time saved has a positive effect on the operating cost which justifies the optimization objectives of adopting this design.

FLAPPER SYSTEM: A flapper isolation door was mounted on the profile of the nipple element below the ball seat, this had an outlet and inlet valve that allows the pumping of pressure in and out of the system to activate the flapper to either open or close depending on the operations objective. To open the flapper, the flapper is designed to activate to full open position at a pressure of 5000psi and to close down at the venting off of the entire pressure to zero psi. The pressure is to be conveyed by a hydraulic line connected to the nipple flapper element, drawn to the surface and terminated at the well head. Enerpac machine is used to activate this pressure. This pressure sensitive flapper performs two main function; namely to isolate the well during completion string testing to determine integrity of the connections and secondly to isolate pressure when HS packer elements is to be activated. As the instrument was tested, it was observed that the flapper started opening at 1200 psi initial pressure and became fully open at 5000psi full pressure. When it opened, it created the same internal diameter of the tubing ID which allowed free flow of well fluid through the well. When it was time to create isolation, the valve of the flow line was turned open thereby bleeding off the pressure in the system to zero psi. This action kept the system tightly closed to ensure an air tight sealing. Pressure pumping unit was then activated by the pumping team. The pressure effectively built up to 5000 psi thereby initiating the packer activations. After setting the packer slips, the packer back side was pressure tested also before re-opening the pressure sensitive hydro-trip nipple sub flapper to allow the well to be produced.

Table 2 Dual Completion Deployment Activity Log-A

S/N	Mat. Deployed	Deployment Time	Cum. Deployment Time	Cost Factor @ \$50000/D (2083.33/Hr)	Cumm. Cost Factor
		0	0	2083.33	2083.33
1	Tubing	45	45	93749.85	93749.85
2	Hydrotrip Run	4	49	8333.32	102083.17
3	Nipple Run	4	53	8333.32	110416.49
4	Hs Packer Run	9	62	18749.97	129166.46
5	Wireline Run Round Trip and Pumping	28	90	58333.33	187499.79
6	Scssv Run	8	98	16666.64	204166.43
7	Space Out	6	104	12499.98	216666.41
8	Landing	7	111	12499.98	229166.39
	Total		**111**		229166.39

Table 3 Dual Completion Deployment Activity Log-B

S/N	Mat. Deployed	Deployment Time in Hrs	Cum Time of Deployment	Cost Factor @ \$50000/D	Cumm. Cost
		0	0	2083.33	2083.33
1	Tubing	45	45	93749.85	93749.85
2	Hydrotrip Nipple Sub Run	4	49	8333.32	102083.17
3	Hs Packer Installation	9	58	18749.97	120833.14
4	Ball Chase and Seat Shear	5	63	10416.65	131249.79
5	Scssv Run	9.15	72.15	16666.64	147916.43
6	Space Out	6	78.15	12499.98	160416.41
7	Landing	7	85.15	12499.98	172916.39
	Total		**85.15**		172916.39

3.2 Discussion on the effect of cost on man hour gained in the application of the simulation of hydrotrip nipple dual completion model

From table 4.2 above, it was observed that based on the smart well completions pressure sensitive flapper designed packer activation system used, which completely eliminated the use of X nipple and XN nipple respectively as a standalone landing nipple, this made it possible for fewer completions sub-assemblies to be deployed in completing the well. Which resulted to less complexity in terms of equipment configuration and less time required to start and finish the completions installation. From table 4.2 and 4.3 respectively we discovered that a total of 45 man hours were collectively spent in running the tubing installations from top to the total well depth. Converting the tubing installation man-hour to rig-time in relation to cost per operating time, would yielded:

\$2083.33per hour x 45hrs = \$93749.85,

With this result, no noticeable margin was observed due to the fact that equal length of tubing was run at the same speed but on different operations.

For the novel Hydro-Trip-Nipple sub, was run 10ft below the hydrostatic set packer at a total operating man-hours of 4.0hr at the rate of 2083.33 per man-hour. When translated to rig time in relation to cost per man-hour it yielded a total of: \$2083.33per hour x 4hrs = \$8333.32. conversely, when compared with running a hydro trip pressure sub as a single component alongside landing nipple, this required running more number of sub assembly component that will coexist with it. The additional component created complexity, resulting to extended man hour which leap jump the rig operating cost to:

(4+4) x 2083.33 = \$16666.64.

The implication is a higher marginal time effect of 8hrs with a higher cost effect $8333.32 required to complete the entire production zones to total depth while running hydro-trip sub separately from landing nipple.

Involvement of wireline run for **option A** to set blanking plug and to pump-in the required pressure that actuated the hydrostatic packer at a setting rate of 2500 psi, the round trip for the whole operation yielded a 28hours operation, which translated to:

28 x 2083.33 = $58333.33hrs.

But **option B** had zero man-hour involvement since there was no need of deploying wireline to set packer, this would save the investors adequate rig time as well as cost and reduced the complexity of running multiple sub-assemblies that usually accompany the installation of nipple separately and a hydro-trip pressure subs separately.

Wait on leakage test was also experimented for the Nipple subs flapper and safety valve flapper. For the running of surface controlled subsurface safety valve, after the initial simulations carried out to test its integrity and ability to prevent leakage while in operations, we subjected the safety valve to a series of test at a different timing scale which is the newly experimented completions techniques being experimented to detect minor leakages that is hard to detect in a 5 minute and 15 minutes SCSSV line test. These test comprised of the conventional 5minutes test, 15minutes at 5000psi according to the normal industry standard and no leakage was found in both 5minutes and 15minutes pressure test. This was repeated 3 times and the volume of gauge value of the hydraulic returned was consistent at 20.5ml for the tree times this was tested which show there were no leakage in the SCSSV lines for both 5minutes and 15minutes test. The total man hour spent in deployment of the SCSSV was 8hrs which amounted to 16666.64. But when compared with a more robust and more prolonged test using the same safety valve but with different standard test time newly invented to run the test for at least 1hr, a gradual drop in pressure was discovered on the graph gauge as the pressure gradually dropped from 5000psi to 4600psi, losing about 400psi, this showed a clear indication that the safety valve would have likely failed after a long time of operation if it was run in the well. However, another safety valve was subjected to 1.00hr test and it was consistent at 21.2ml continuously for 3 consecutive test conducted under the same condition of test time and pressure and it showed consistency in the graph which is an indication that there was no leakage. The total man hour spent was 9.15hrs and the total rig cost it attracted was:

9.15hrs x $2083.33 = $19062.4695

This showed a difference margin of $2395.8295. The cost of work over is usually times two of the total rig's operating cost of the first completion job due to well string retrieval, well re-condition and tools redeployment in hole. This means that the extended 1hr test conducted had saved the company a total rig cost of:

$172916.36 x 2 = $345832.72.

Therefore, this model has created a new technical normal to detect leakages that could affect production string through the SCSSV flow line or flapper a prolong production operation as the well is put on production stream. Hence leakages that could not be detected in a 5 minutes and 15 minutes' tests were able to be detect in a 1hr test using this new wait on leakage testing model.

On spacing out of the completion and the landing the simulation conducted before actual completion showed that both had similar operations requirements. The man hour spent and the effect of the completions man hour is practically the same, resulting to $12499.98 for option A well design and $14583.3 for option B well designs for both space out and landing of the well completions strings respectively. Hence no significant marginal cost impact found on this space out technique.

Table 4: The Resultant cumulative man hour effects

Time Difference Between Well A And Well B		
Well	**Total Man Hrs**	**Total Cost Factor $(Usd)**
Well A	110	229166.39
Well B	85.15	172916.39
Optimized Cost Margin	**24.85**	**56250**

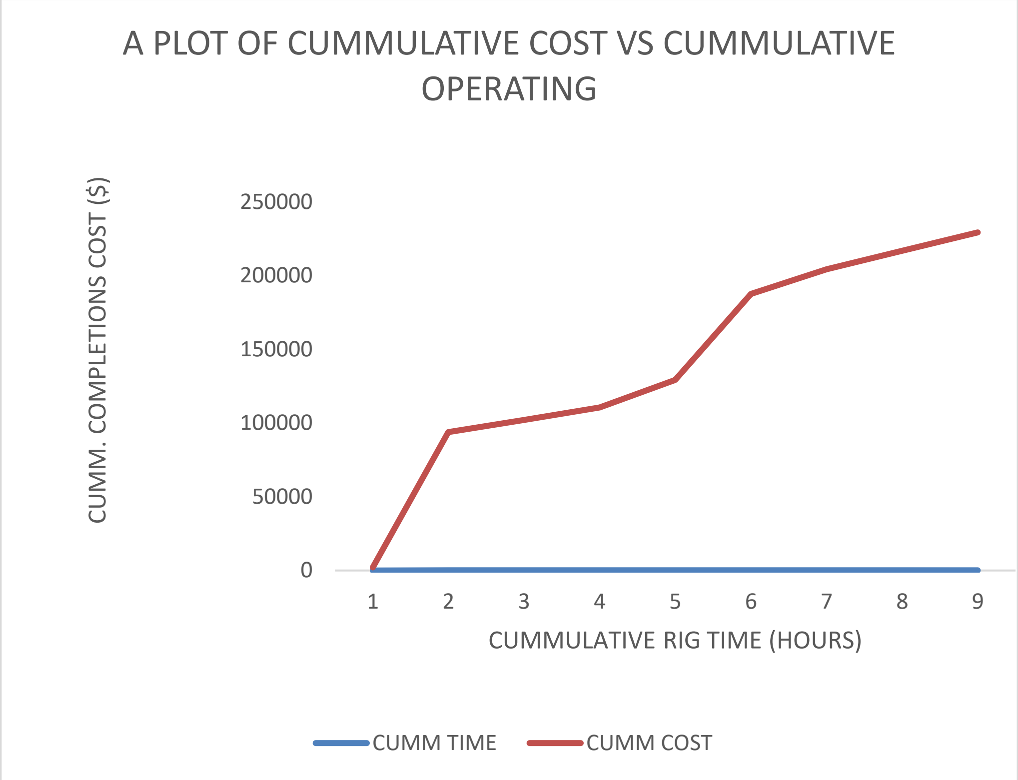

Figure 13: The comparative advantage trend-line of cost vs time between the two dual completions methods.

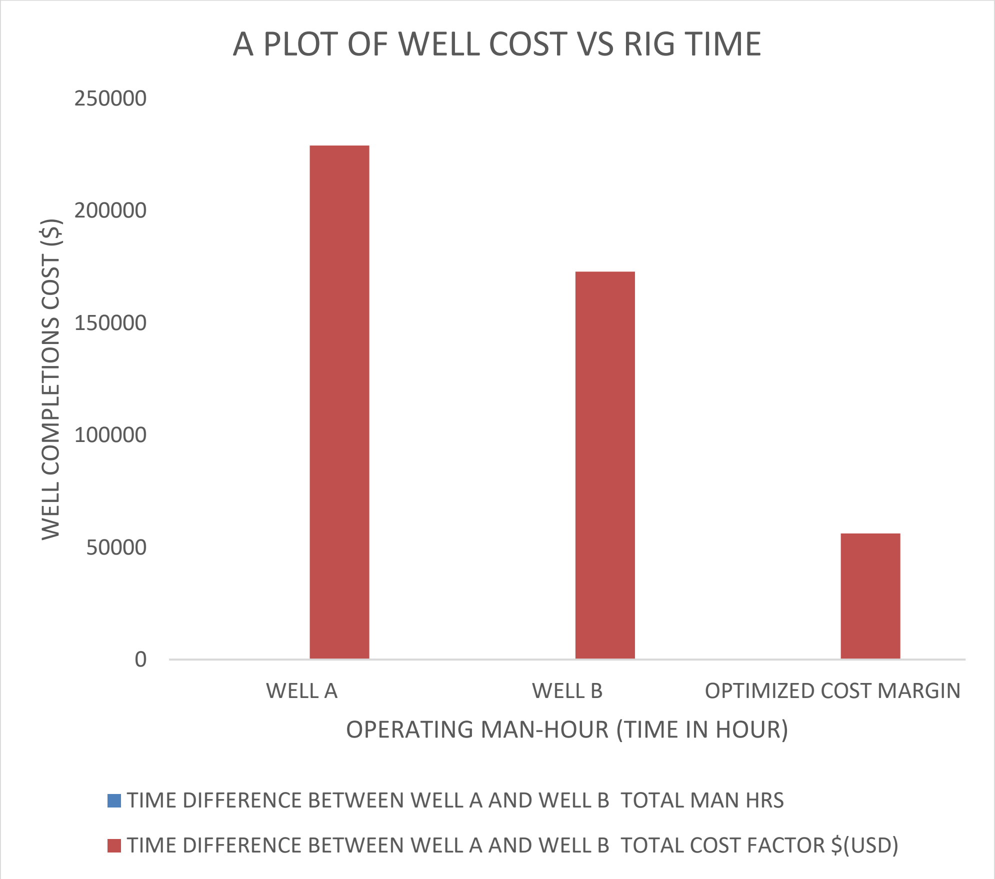

Figure 14: The comparative advantage column of cost vs time between the two dual completions methods.

3.3 Data analysis for the smart pressure sensitive flapper operating system for packer actuation

The graphical representations on figure 3.1 above shows the marginal effects of between both completions methods and their comparative advantages. The first column depicts well design option A method and the cost required to run the completions, it would be observed that well design option A method has the highest column at $229166.39 while well design option be had a much lesser column at the rate of 172916.39. The last column in the graph depicts the total amount of man hour saved as a result of applying the novel smart well pressure sensitive hydro trip nipple sub packer activation system.

The results in table 3.3 showed that well design option A which was completed using wireline operated system required a total of 110 hours operating time to start and finish the dual completions run, while well design option B required about 85.15 hours to start and finish the completions by applying just the hydro-trip nipple sub and without the use of wireline.

Both methods option - A and option - B resulted to a total operating cost of $229166.39 and $172916.39, respectively. When comparing the difference between them, it would be observed that method B required less time and less complex operations activities which resulted in saving about 24.85 total man hours and which translated to $56250 dollars saved by applying hydro triple sub technique.

4. Conclusion

i. From the critical evaluation of the smart well packer actuation equipment designed with the attachment of a pressure sensitive flapper mounted on the hydro-trip nipple sub, we were able to determine responsiveness of the activating pressure rating of the device, through a flow line tied to a surface gauge and this smart packer activation system was able to effectively reduce operation time and lesser operating cost by over 50 percent.

ii. Through this new designed flapper mounted nipple sub system, it was effectively used to completely eliminate the use of wireline operation during well completion installations thereby eliminating the nonproductive time usually caused by multiple wireline run in the process of completions installation and hence helped in reducing cost of operation required to complete the well successfully and also reduced operational man-hour required to complete the completions installation.

iii. The new surface testing procedure developed in the course of this work for detecting and troubleshooting long term cumulative string and valve failure due to unidentifiable pressures usually caused by minor leakages within the safety valve sealing system, this new test procedure deployed in this course work was effectively able to detect and troubleshoot this leakages when it was subjected to a critical long term test that doubled and tripled the initial test duration conventionally used in earlier processes, thereby proving to be an effective mechanism to be used in troubleshooting safety valve systems on the surface before actual installation. This practice was able to prevent the operational time, cost and other technical resources required to pull-out the entire completions string and do a second re-completions of the well, after discovering leakages due to failure caused by conventional short term test. Hence this new procedure optimally reduced operational cost and rig time.

Finally, this finding enable us to determine that the use of brass shear screws is faster in terms of operations, more operationally friendly and safer as well as being more effective in activating hydrostatic packer at a much lesser cost and reduced man-hour, than when compared to using steel shear pins, which often required prolong rig time and extra cost with several chances of technical complications during the deployment process

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