FINAL YEAR PROJECT II

DISSERTATION REPORT

"Design Methodology of Overshot Inverted Swellable Elastomer Packer"

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CERTIFICATION OF APPROVAL

DESIGN METHODOLOGY OF OVERSHOT

INVERTED SWELLABLE ELASTOMER PACKER

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TRONOH, PERAK

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CERTIFICATION OF ORIGINALITY

This is to certify that I am responsible for the work submitted in this project, that the original work in my own except as specified in the references and acknowledgements, and that the original work contained herein have not been undertaken or done by unspecified sources or persons.

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ABSTRACT

During past 7 years, swellable elastomer technology has been introduced to the oilfield and its acceptance has been so rapid that its scope of application has been rapidly expanded. But throughout this paper, the usage of Swellable Elastomer Packer (SEPs) has been challenged as existing-to-new tubing connector during workover. This project needs to be constructed as such the Inverted SEP manages to handle wellbore parameters from the inside of the tubing itself. Three primary challenges must be addressed when designing SEPs for the above stated applications:

1. The downhole conditions; i.e., the main parameters to which the tool will be subjected such as the downhole pressure increase and the average temperature drop of the sealing elements.

2. Thermal contraction of the sealing element; i.e., contraction that occurs during high rate pumping cooling effect will cause lower anchoring force of the sealing elements.

3. Design concept & workover method; i.e., thorough simulation and discussion on combined technology between Overshot BHA and Swellable Elastomer Packer (SEPs) modified for inward swelling and new tubing latch-on method.

These applications of workover scenario include condemn or damaged of the top subsurface tool (i.e. Surface Control Subsurface Safety Valve SCSSSV and Side Pocket Mandrel SPM). With this new technology – Overshot Inverted Swellpacker, same result with lower operation margin cost can be achieved.

This paper describes the technical challenges and discusses resulting design methodology based on modeling (downhole parameters, anchoring forces, thermal contraction measurements, tool workover simulation and etc.) that have been developed to resolve these issues. This design methodology is not limited to only workover but also applicable to any scenario with dynamic loads on SEP applications such as in high rate injection wells, etc..

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Author’s salutation would be incomplete without giving credit to software developer of Halliburton LANDMARK WELLCAT©, MSCSoftware MARC Mentat and Autodesk 3DsMax which assist in this project completion and its objectives fulfillment.

All contributions are much appreciated.

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1. INTRODUCTION

1.1. Background of Project

It has been approximately 7 years since swellable technology was introduced to the oil and gas industry, and since its introduction, many changes in the technology have taken place. Initially, the main application was the development of swellable elements for packers. Swellable packer technology has rapidly been up taken by the oil industry. Since the introduction to the market right after the millennium several thousand units have been delivered to operators worldwide. Applications vary and the application envelope is continuously being widened. Swellable packers are run in open hole and case hole, in extended reach drilling (ERD) wells, in multilateral (MLT) wells, in conjuction with intelligent completions, in hydraulically fractured wells, in combination with cement, etc., in producers and in injectors in low temperature to HTHP fields. Swellable packers can be divided in two main categories based on the swelling mechanism; i.e., oil swellable and water swellable packers.

Oil swellable packers are based on the swelling properties of rubber in hydrocarbons due to thermo dynamical absorption of oil into the rubber matrix. The packer consists of the base pipe with a rubber elastomer element wrapped and bonded onto the pipe with anti-extrusion end rings on both sides of the element. The packer swells up to 200% sealing the annulus around the pipe. Once deployed, the rubber retains its flexibility, allowing the swellable packers system to adapt to shifts in the formation over time, retaining the integrity of the seal. The packer has no moving parts and requires no setting tool or pipe manipulation to set. The differential pressure the packer can withstand is dependent on the packer element thickness and the hole diameter and the element length. Swellable packers can be manufactured on all pipe sizes, which make usage of the technology possible in literally all hole sizes.

But, as technology grows, the swellable elastomer packer enhancement is challenged by altering its design to Inverted Swellable Elastomer Packer. Instead of swelling outwards the swelling element of the packer will eventually swells inwards. The usage of this packer is so much more different than the zonal isolation purpose, this Inverted Swellable Elastomer Packer will be widely used in workover operation.

Instead of serving the purpose of zonal-isolation, this Inverted SEPs will be the connector between the new tubing and the existing tubing in workover.

More simulation and data testing needed for this is the pioneer project of Overshot Inverted Swellable Elastomer Packer. Throughout this project, all data applied is based on Baram Field Well X, and common operation such as Injection and pressure test is all based on real operation standard operating procedure (SOP)

1.2. Problem Statement

The implementation of swellable elastomer packer is given new challenges by altering the design into Inverted Swellable Elastomer Packer. The theory is as simple as inverting the swelling part which previously swells outward when the new one here is swelling inward.

The first problem of the basic downhole tools is leakage or condemned of the upper part tools of the tubing above the top packer which are Tubing Retrievable Surface Control Subsurface Safety Valve TR-SCSSSV and some of it may include Side Pocket Mandrel SPM. The TR-SCSSSV is the first crucial barrier between the downhole and surface facility (wellhead). Common problem of the TR-SCSSSV is the flapper itself is stucked, either in jammed-open position or in jammed-close position. And the basic maintenance would be Insert String operation which the well services company will lock open the flapper and install a smaller version of SCSSSV named Wireline Retrievable WR-SCSSSV at the profile inside the jammed open TR-SCSSSV. This operation usually because of cost of workover for the whole tubing is much higher than the Insert String operation, but the new installed WR-SCSSSV I.D is smaller than the tubing itself because it is installed inside the TR-SCSSSV. So, by using the Inverted Swellable Elastomer Packer in new way of workover, the marginal cost to workover the whole tubing will be less and the Insert String operation isn't in need anymore.

The previous SEPs are installed on the outer sides of production tubing, so for the acid stimulation operation and/or hydraulic fracturing, the thickness of the swelling elements will have been affected by the operation. As in this paper, will explained more about the challenges faced in this experiment is about how to maintained the swelling thickness of the swelling element because the Inverted SEPs will be directly in contact with those chemicals pumped..

The other problem on the previous design of Overshot Inverted SEPs is the mule shoe guide at the end of the toolstring bottomhole assembly unable to rotate and latch onto the longstring, because of dual string tubing configuration factor.

All of the situations above can be summarized as below:

1. The conventional method to cure TR-SCSSSV and SPM problem will result either in higher marginal cost for workover or smaller I.D at the WR-SCSSSV installation part. And the Inverted SEPs usage in new workover method will solve both of the problems.

2. The high-rate pumping operation (i.e. hydraulic fracturing, acid stimulation) can affect the swelling thickness of the SEPs based on thermal contraction and anchoring force.

3. The previous design of the SEPs with mule shoe guide at the end of the toolstring bottomhole assembly unable to rotate and latch onto the longstring, because of dual string tubing configuration factor.

1.3. Objective and Scope of Study

Objective of this project are:-

a) To study on the design methodology of Inverted Swellable Elastomer Packer, this is an enhanced design of the previous Swellable Elastomer Packer.
b) To solve the problem of high-rate pumping operation; this will affect swelling thickness of the SEPs.
c) New mule shoe guide design to assist in tubing-latching problem.

The scope of study is focused on the modelling of the Inverted SEPs and design simulation of the new workover method. Four factors tested throughout this project - temperature drop, thermal contraction, anchoring forces, swelling rate and design simulation.

1.4. Relevancy of the Project

As mention in the problem statement and objective above, this project is mainly to study on the efficiency of this new invention – Overshot Inverted Swellable Packer for the top-half completion workover.

1.5. Feasibility of the Project

WR-SCSSSV was not considered as permanent CL solution by regulatory requirement. And for SPM leakage problem, workover is the only solution prior to it. Main advantages of this innovative application are:

1. Lower cost relative to whole tubing workover
2. Easier and faster remedial work
3. New design methodology of this workover will not commingled zone from SS with the LS.

There are major operations which needed to be fulfilled for this application to be feasible which are:

1. Production from SS tubing is controlled by using plug method.
2. New design of mule shoe guide for the overshot needs to be fabricated in order to reduce possibility to fail for the tubing stub latch-on.

2. THEORY AND LITERATURE REVIEW

2.1. Hydraulic Fracturing and SEPs

With the growth of SEPs for stimulation treatments, additional research and development efforts have been devoted to investigation for other applications. One of the areas considered has been hydraulic fracturing, and by combining multi-disciplined fields of expertise, reliable designs have been developed to support this application.

The use of SEPs in hydraulic fracturing mainly focuses on the North American market at present, but other geographical areas can benefit from the results of the design methodology developed.

All knowledge and expertise learned and documented for this application can be used for any application where a cold fluid is pumped down the tubing, resulting in a cool-down effect in the element from the tubing side.

The objective(s) of a hydraulic fracturing treatment are:

1. To bypass near-wellbore damage to re-establish natural productivity
2. To extend a conductive path into a formation to increase productivity beyond the natural level
3. To alter flow in the formation.

To achieve the fracturing objective, a sand or proppant-laden fluid is pumped downhole. Fractures in the formation are created by pumping the fluid into the formation above the formation fracture gradient (FFG). This means that the fluid is pumped into the well faster than the fluid can escape into the formation. Pressure rises, and at some point, the formation will break.

The breakdown and early fracture growth expose new formation area to the injected fluid: The rate of fluid loss increases, but as long as pump rates are maintained higher than the fluid-loss rate, the newly created fracture will continue to propagate and grow. Once the pumping stops, and the injected fluid leaks off, the fracture will close and the new formation area will not be available for production. To prevent this from happening, a proppant (sand) is added to the hydraulic fluid to be transported into the fracture. When pumping stops, and fluid flows back from the well, the sand remains in place to keep the fracture open and maintain a conductive flow path for the increased formation flow area during production.

Pump rates and volumes of fluids pumped are usually high and can be anywhere from 40 to 90 bbl/min. Due to the high rates, the fluids will not heat up much while being pumped downhole, resulting in a cooling effect of the fluid from the tubing side.

The temperature drop mentioned above has two major effects on the packer; thermal contraction of the swellable element and thermal contraction of the tubing will occur; these changes result in pulling forces on the packer. Both effects should be modeled and quantified to enable the SEPs to be designed appropriately for the application.

The above mentioned scenario with the dynamic load on the SEP elements does not appear during hydraulic fracturing only; injection wells and other stimulation operations such as acid treatment and gravel packing where the fluid pumped will result in a cool down are also affected. Therefore, both the design of the SEP and the job execution for hydraulic fracturing will require the combination of several technologies and competencies.

2.2. Describing Downhole Condition

As is the case with any model, the results rely heavily on the input that is used. Two parameters play a major role in the design of any SEP, and for applications in a stimulation operation, temperature and pressure are particularly important.

Pressure has always been one of the main parameters for any SEP design, but for a stimulation application, the impact of temperature on the differential pressure behavior of the SEP has to be taken into account. Proper estimation or description of the downhole conditions, therefore, is crucial to the proper design of an SEP for stimulation application.

2.3. Temperature Drop

The temperature drop that the SEP will experience has a significant impact on the performance of the packer. Therefore, it is critical to use accurate input numbers and a realistic model to predict the temperature drop that the packer will experience. The definition of the temperature drop is:

The difference in temperature of the rubber element at the start of the treatment and the average packer element after the packer has been exposed to the cooler liquid at the tubing side:

$$\Delta T = BHST - Tavg$$

Where

ΔT: Temperature drop that the SEP will experience.

BHST: Bottomhole Static Temperature; the temperature at which the packer was set; usually reservoir temperature. Tavg: Average temperature in the sealing element.

To calculate the average element temperature, a temperature profile through the element will be calculated. This calculation uses two 'boundary conditions':

T_{fluid}: This is the temperature of the fluid at packer depth.

T_{EWB}: Temperature at the element/wellbore (EWB) interface.

The injected fluid temperature will be calculated using the surface temperature of the fluid and the heating effect when the fluid is being pumped down the tubing. Computer software is available that can be used to calculate this temperature.

The T_{EWB} can be different from the BHST, depending on input from the operator. Some operators assume a certain cool down of the formation, resulting in a lower T_{EWB} than the BHST or reservoir temperature. In that case, the temperature profile continues into the formation for a certain distance, resulting in a lower temperature at the element/wellbore interface.

In the model used, T_{EWB} is an input used to simulate either scenario and analyze the impact of any cool down effect.

The temperature profile is calculated based on the two boundary conditions mentioned above and the following assumptions:

- Steady state heat conduction through the element
- No cooling effect at the ends of the SEP.
- Tubing wall is at Tfluid.

Initially, the fluid in the tubing, the element and the formation are at reservoir temperature (BHST). In the diagram in Figure 2, the blue area represents the fluid at the tubing side, the dark grey is the packer element, and the brown is the formation. The light gray line between the SEP element and the fluid is the steel.

As soon as a cold fluid is pumped down the tubing, the inner part of the element will be cooled down to the temperature of the injected fluid. During a certain period of time (transient time), the profile will change (see Figure 3.) After an 'infinite' time of pumping, the temperature profile through the elastomer element stops changing with time; when this occurs, a steady state has been established. (See Figure 4).

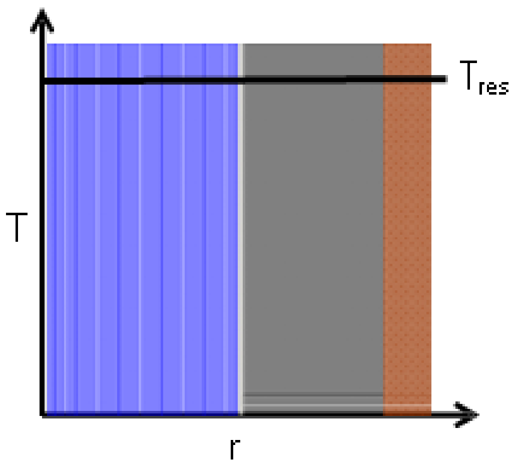


Figure 1 - Relationship of SEP element, fluid at tubing side, steel, and the formation.

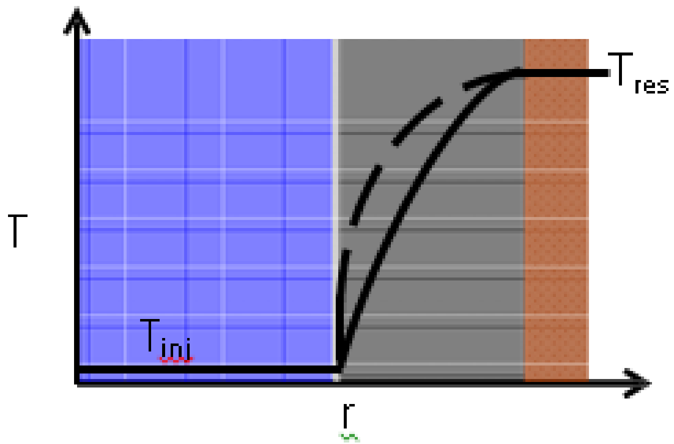


Figure 2 - Changes in profile due to temperature changes.

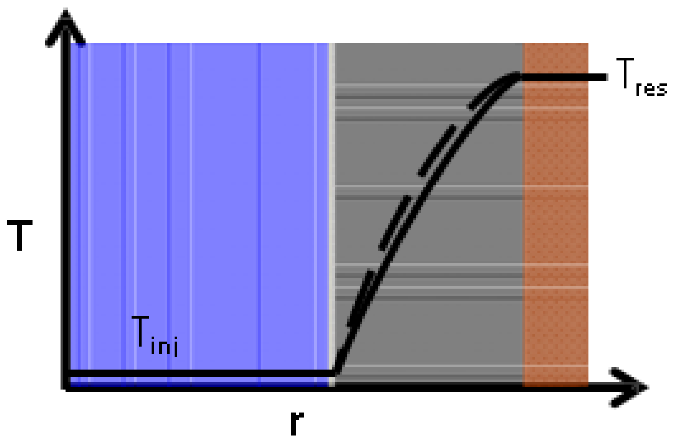


Figure 3 - A steady State Profile has been established.

A mathematical expression based on a stationary heat balance over the element will allow the user to calculate the temperature at any given radius in the SEP element. This expression is used to calculate T_{avg} by integrating the temperature profile between the ID and OD of the rubber element. See Figure 5.

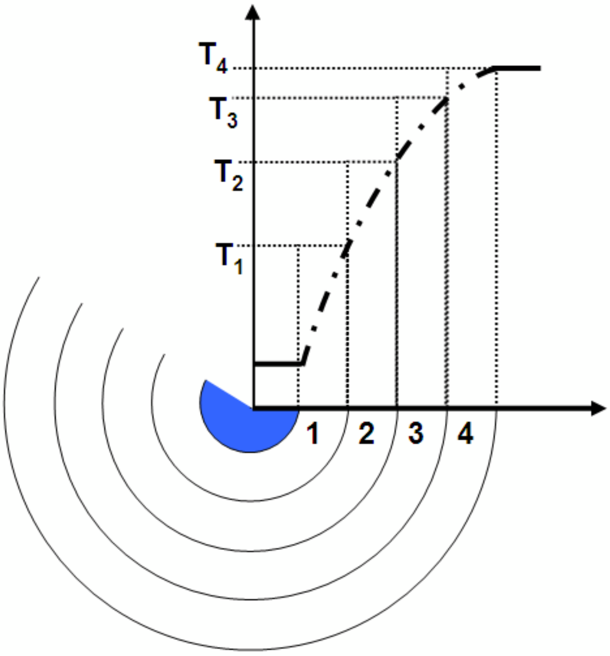


Figure 4 - Schematic of the temperature profile and Tavg.

T_{avg} is obtained using the following expression:

$$T_{avg} = \sum_i \frac{mass_i}{mass_{total}} \cdot T_i$$

Where

$Mass_i$	:	Mass of ring i
$Mass_{total}$	:	Total mass of the rubber element
T_i	:	Temperature in ring i

Ti is calculated using stationary heat conduction through the element8:

$$\frac{T_i - T_{WBT}}{T_{fluid} - T_{WBT}} = \frac{\ln\left(r_i / R_{OD} \right)}{\ln\left(R_{ID} / R_{OD} \right)}$$

Ti	:	Temperature at ri in the element
T_{WBT}	:	Temperature of the element at the wellbore OD or ROD
T_{fluid}	:	Temperature of the element at the base pipe or RID
r_i	:	Radius i in the element
R_{ID}	:	Inner radius of the element
R_{OD}	:	Outer radius of the element

A full-scale test was conducted to verify the assumptions and validity of the steady-state model. During the test, it took approximately 1.5 hours of pumping to establish constant temperature throughout the rubber element. The experiment confirmed that a constant temperature profile is established before general fracturing operations have finished.

Even if the actual temperature profile has not been fully developed, the method described above is the worst case scenario; the temperature profile based on steady-state heat conduction results in the lowest T_{avg} possible, based on T_{fluid} and T_{WBT} as inputs.

2.4. Thermal Contraction

As with any material, the swellable elastomer element of the SEP will contract during a drop in temperature. The thermal expansion/contraction of the elastomer is roughly 10 times larger than the coefficient for steel. This means that with increasing temperature drop, contraction effects will be more severe. The contraction will lead to a drop in internal element pressure; ultimately, it will result in a physical shrinkage, and the pressure seal will be lost.

To be able to link the temperature drop to SEP performance, several tests have been carried out on laboratory scale and full scale experiments. The test results show that an SEP can handle a certain temperature drop when given sufficient time to swell. However, the differential pressure holding capacity is reduced, if the temperature drop is too large to handle at that particular point in time.

From the experiments, it is possible to quantify the additional amount of time required to allow the SEP to build up sufficient internal pressure so that the temperature drop does not affect the performance of the SEP.

Using the model, it is also possible to quantify the additional differential pressure (DP) capacity required to be able to handle any reduction in differential pressure holding capacity, should the temperature drop be too large at the time of the fracturing operation. The excess capacity will allow operators to minimize the time between setting the SEP and the actual stimulation treatment.

To determine the loss of DP capacity of the SEP, full scale pressure testing has been conducted at several temperatures, and the results have been used to develop the pressure reduction part of the model.

The model is built into an in-house-developed simulator that will allow the user to design the packer for the application, based on some vital well and fluid information. The model will predict the time it takes to seal and to develop to a certain differential pressure. The differential pressure performance as a function of the openhole diameter is shown as a graph along with the time to seal

The stimulation module of the simulator will establish the temperature drop that the packer can take without loss of the pressure rating and will determine whether downgrading of the packer performance is necessary. This determination will be based on the temperature drop and the planned timing of the treatment. By either changing the length of the element (adding extra differential pressure capacity to the SEP) or allowing the SEP to set for a longer time (building up sufficient internal pressure), the optimum design for the application can be determined without the risk of losing a hydraulic seal during the treatment.

2.5. Anchoring Forces

In addition to the impact on the sealing performance of the packer, the temperature drop also causes shrinkage in the tubing. This shrinkage will create pulling forces that the SEP must be capable of withstanding. Therefore, anchoring force calculations are required to verify that the SEP will be capable of holding the forces that are induced by the shrinkage of the tubing.

Anchoring forces are based on friction forces between the confining material; i.e., casing or open hole, and the rubber element. The friction forces are calculated as follows:

$$F_{friction} = F_N \cdot \mu$$

Where:

Ffriction	:	Friction force
F_N	:	Normal force
μ	:	Friction coefficient.

Several tests were carried out to provide the capability to quantify the friction factor and the normal forces required to calculate the resulting anchoring forces that the packers would generate at the time of the fracturing operation.

For the case history, the forces resulting from the temperature drop are compared to the anchoring forces that the SEP will generate. Obviously, the anchoring force of the SEP should be larger than the forces acting on the SEP.

2.6. Pressure

The pressure to which the SEP will be subjected during a hydraulic fracturing operation is most accurately described using actual formation parameters. The formation fracturing gradient (FFG) is the most reliable parameter to use for the differential pressure that the SEP must be capable of withstanding during the job.

Using the surface treating pressure and back-calculating the downhole treating pressure is not very accurate, as the fluids are changing rheological properties as they are pumped downhole. The fluids are designed to ensure low-friction parameters down the tubing; viscosity of the fluid is kept as low as possible. Since proppant must be transported to the fractures that are created, the viscosity should increase before the proppant reaches the formation face.

Generally, a time-delayed gelling process ensures that the fluid properties are optimized — low viscosity in the tubing and increased viscosity just before the fluid reaches the formation. This means that the surface treating pressure is always higher than the pressure differential over the packer: The friction pressure is included in the surface treating pressure:

$P_{treating} = P_{friction} + P_{fracture} - P_{head}$; where;

$P_{treating}$	:	Surface treating pressure (BHTP)
$P_{friction}$	:	Friction pressure
$P_{fracture}$	:	Pressure inside the fracture
P_{head}	:	Hydrostatic pressure above the packer

Pipe friction is a major term in the equation above: Both the size of the tubulars and the fluid properties have strong influences on allowable pump rates. The pressure inside the fracture is related to the rock strength properties. As a minimum, the downhole pressure needs to be higher than the FFG at the packer depth.

It is obvious that the use of FFG is a more reliable parameter to use for the SEP design than using estimates for surface treating pressure and for the friction pressure. FFGs are usually obtained from offset wells or (extended) leak-off tests (LOT).

2.7. Literature Review

There are numbers of research papers have been done in the past few months on the fundamental of drilling fluids, chemistry of emulsifiers, and mud testing. All of them were reviewed and studied by me.

No.	Title of Paper / Research / Work	Author	Date
1	**Deployment of Swelling Elastomer Packers in Shell E&P – SPE 92346**	Kleverlaan, Martijn, van Noort, Roger H., Jones, Ian	February 23rd, 2005
2	**Solid Expandable Tubulars Slim Well Design and Isolate Zones for Brownfield Redevelopment in Oman – SPE 97426**	Morrison, W., Sanders, T., Leuranguer, C	September 12th, 2005
3	**Applications of Underbalanced Drilling Reservoir Characterization for Water Shut Off in a Fractured Carbonate Reservoir - A Project Overview – SPE 93695**	Murphy, D. Davidson I., Kennedy, R., Busaidi, R., Wind, J., Mykytiw, C., Arsenault, L	March 15th, 2005
4	**Run-and-Forget Completions for Optimal Inflow in Heavy Oil – SPE 97336**	Freyer, R.	Nov 1st, 2005
5	**Swell Packers: Enabling Openhole Intelligent and Multilateral Well Completions for Enhanced Oil Recovery – SPE 100824**	Hembling, Drew; Salamy, Salam; Qatani, Abdullah,; Carter, Neale; Jacob, Suresh	November 13th, 2006
6	**Innovative Completion Technology Enhances Production Assurance in Alaskan North Slope Viscous-Oil Developments – SPE 97928**	Triolo, M.T., Davis, E.R , Buck, B.R., Freyer, R., Smith L	November 1st, 2006
7	**Swellable-Packer Technology Eliminates Problems in Difficult Zonal Isolation in Tight-Gas Reservoir Completion – SPE 108720**	Antonio, Luiz; Martinez, German; and Barrios, Oscar:	March 28th, 2007
8	**Case Histories: Liner-Completion Difficulties Resolved With Expandable Liner-Top Technology**	Smith, P, Williford, J	June 13th, 2006

9	**Expandable Liner Hanger Application in Arduous Well Conditions Improves Reliability: A Case History – SPE 88510**	Cantu, J., Smith, P., Nida, R	October 18th, 2004
10	**Baram Well Intervention PCSB SKO Sarawak & Drilling Division KLCC; Notice of Workover Operation Baram Alpha-22**	Larissa M. Dasan, Fairuze Yahaya, Eddy Samaile	March 20th, 2012
11	**When Control Line Failed, What is the Alternative? West Malaysia Experience**	M. Abdul Razak, B.A. Pate, Z. Ismail M. Ibrahim	October 24th, 2012

Table 1 : List of Studied and Analysed Papers

2.7.1. Deployment of Swelling Elastomer Packers in Shell E&P – SPE 92346

Three different types of application of swelling elastomer packers are presented in this section – Liner Completion, Production Isolation and Expandale Open Hole Clad.

Liner Completion type of SEPs run together with the completion and set between the slotted liner to hold the completion to the formation irregularity structure.

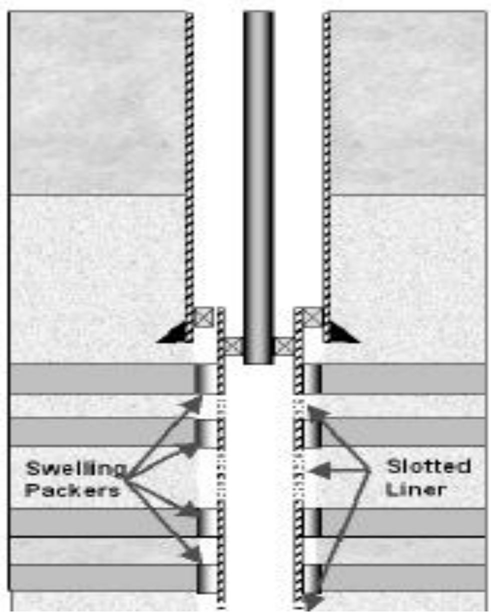


Figure 5 - Swelling Packers in an Open Hole Completion

The swelling packer is all run with a thin diffusion barrier and a low swelling outer layer to prevent premature swelling.

One of the features of the SEPs which is flexible expansion permit it to expand irregularly through the formation structure.

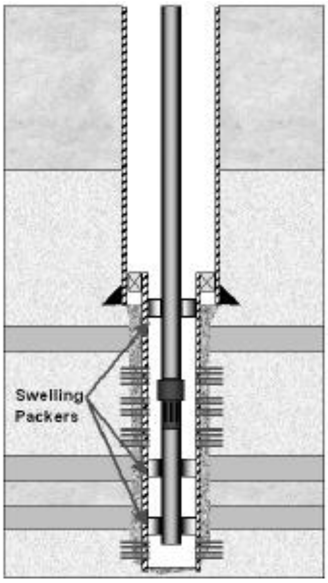


Figure 6 - Swelling Packers used for Produciton Isolation

Production Isolation type of SEPs swells by themselves can be logically used as an alternative to mechanically or hydraulically set packers. The main drivers for this are a straight cost saving on the packer as well as the elimination of any extra running or setting trips with the associated risks.

2.7.2. Solid Expandable Tubulars Slim Well Design and Isolate Zones for Brownfield Redevelopment in Oman – SPE 97426

The Fahud water flood project is a major brownfield redevelopment project and a key component to PDO's future production plan. Key value drivers for the successful project delivery are selecting the right recovery mechanisms for the target reservoirs and achieving low-cost well delivery through standardization and technological innovations.

2.7.3. Applications of Underbalanced Drilling Reservoir Characterization for Water Shut Off in a Fractured Carbonate Reservoir - A Project Overview – SPE 93695

The completion was installed in two stages. The first stage involved running a packer and a tailpipe complete with a preset plug. With the DHIV closed, the packer and tailpipe were run in the hole on drillpipe and the assembly set in the liner below the concentric casing PBR (fig 7). The plug and packer provided isolation from the reservoir allowing the concentric casing and the DHIV to be retrieved. The second stage involved running the production tubing into the well and stabbing it into the preset tailpipe.

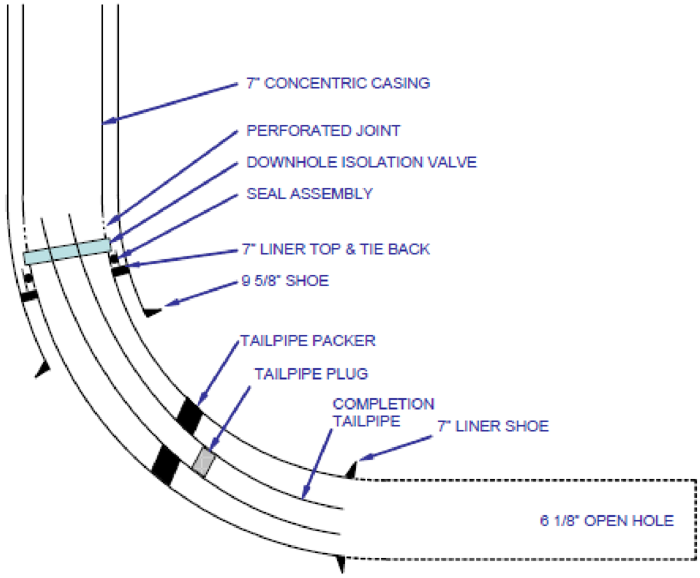


Figure 7 - Fracture Carbonate Case Studies Swellpacker Well Schematic

2.7.4. Run-and-Forget Completions for Optimal Inflow in Heavy Oil – SPE 97336

Three systems for optimizing heavy oil production discussed below include:

a) Short swellable elastomer packers (SEPs) to arrest annular solids transport.
b) Zonal isolation straddles for water shutoff applications.
c) Downhole low-cost autonomous inflow control systems including steam control.

The problem was solved by optimizing screen type and openings, and installing SEPs downstream in the shale sections along the well. A production logging tool (PLT) was run across the reservoir interval. Clear indications showed increased pipe flow across the packers indicating no annular flow.

2.7.5. Swell Packers: Enabling Openhole Intelligent and Multilateral Well Completions for Enhanced Oil Recovery – SPE 100824

This project is carried out by Saudi Aramco, intelligent and multi-lateral wells evolving as key completion technology to enhance and maximize hydrocarbon recovery. Current techniques either involve the cementing of the mother-bore and/or the use of complex mechanical systems and packers to isolate individual zones.

So, an isolation device has been developed which uses a rubber elastomer bonded onto a base pipe. The rubber swells in hydrocarbon and provides an effective seal down hole between the base pipe and the openhole to maintain zonal isolation in even the most complex environments.

Laboratory testing as below:

a) Swelling (verify swelling of swelling packer in different crude oils)
b) Sealing capacity (swelling packer ability to withstand DP after swelling)
c) Expansion rate (time for the rubber element to seal and hold DP)

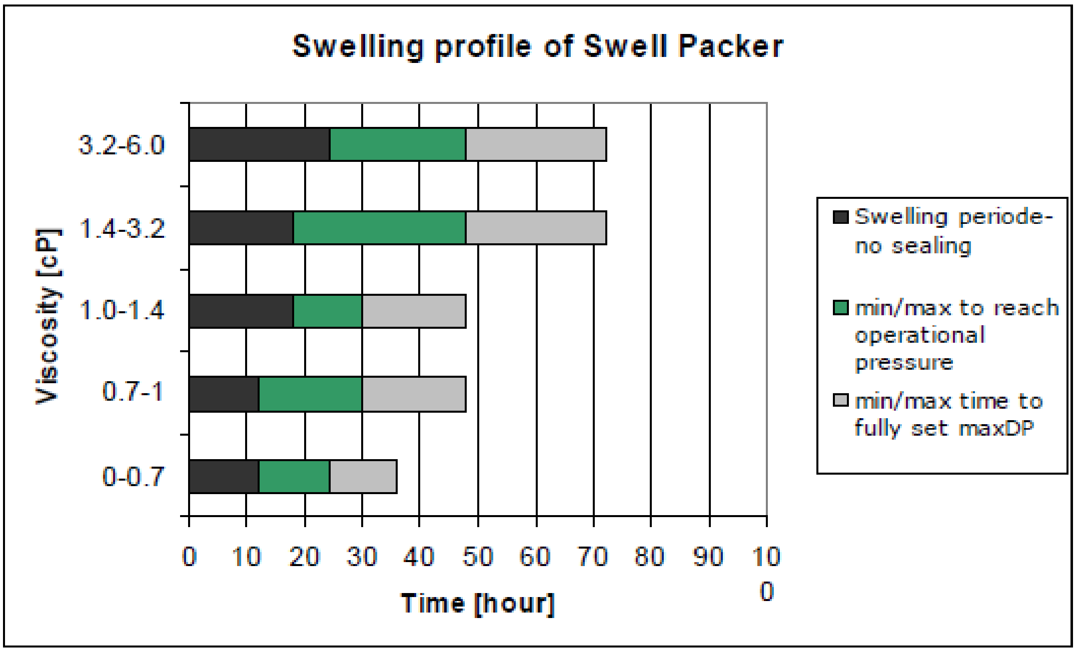


Figure 8 - Swelling Profile vs Time

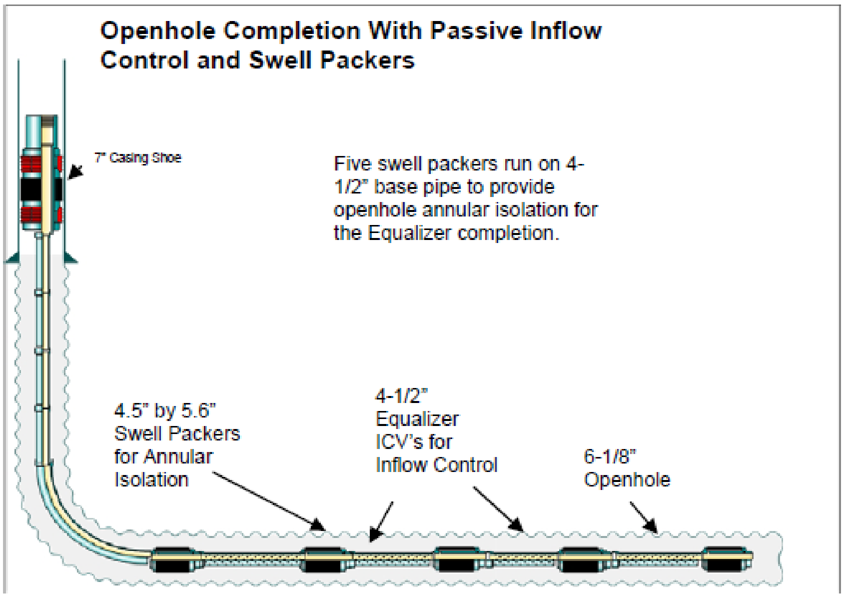
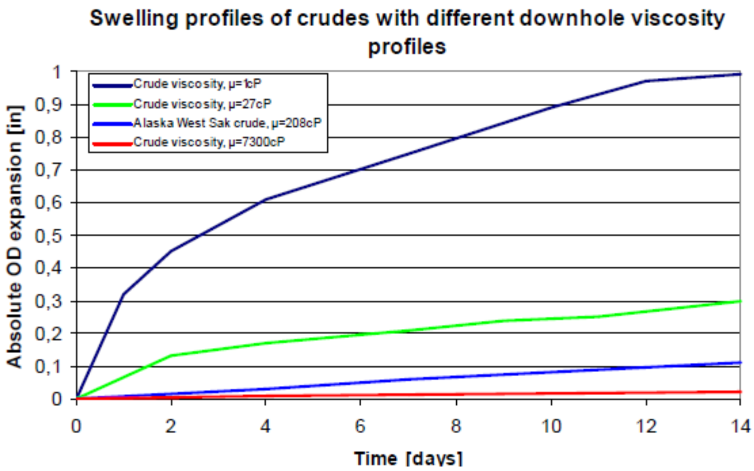


Figure 9 - Shayba Future Well Design

2.7.6. Innovative Competion Technology Enhances Production Assurance in Alaskan North Slope Viscous-Oil Developments – SPE 97928

In the challenging North Slope operating environment, use of innovative production equipment has provided solutions to zonal isolation and packer integrity problems in viscous oil reservoirs. The application of SEPs alleviating many of shortcomings and dif ficulties associated with cement placement and other annular isolation devices.



Graph 1 – Viscosity Effects on Swelling Curves

2.7.7. Swellable-Packer Technology Eliminates Problems in Difficult Zonal Isolation in Tight-Gas Reservoir Completion – SPE 108720

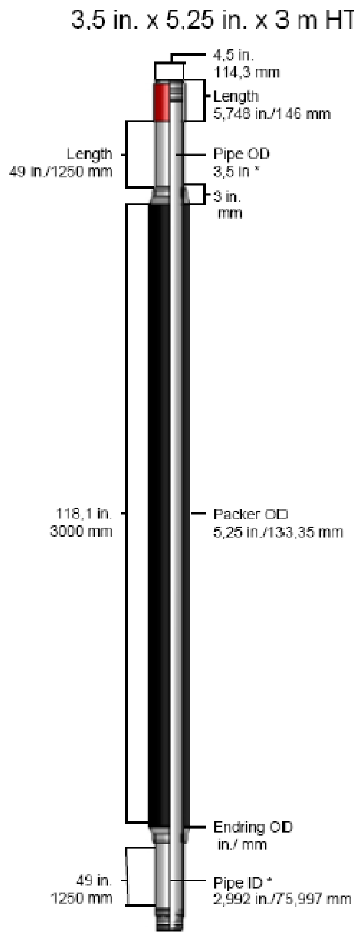


Figure 10 - Swellable Elastomer Packer Designed for Vasai East

Requirements included for the challenge of Vasai East Field in this western offshore India:

a) Oil Production without breakthrough of gas and water

b) Effective hydraulic seal in washed-out hole conditions

c) Contingency options for intervention, if needed.

Design name: 3.5in x 5.25in x 3m
Fluid Viscosity (cP): 0.35
Required DeltaP (psi): 990
Temp at Packer Depth: 149:HT app
Volume Swell % at Hole ID: 55%
Time to Fully Set(day): 9
Time to operational DP(day); 7
Time to First Seal(day): 4
DP at Hole ID(bar): 125
DP at Hole ID(psi): 1807

2.7.8. Case Histories: Liner-Completion Difficulties Resolved With Expandable Liner-Top Technology

The use of an expandable liner hangar system using hydraulic pressure to set the liner hanger proved that it is possible to provide a gas-tight seal, even in extremely shallow liner tops. In addition, the improved flow geometry to provide pipe movement during cement placement improved the success of the primary cement job.

The operator was able to save the cost of a tie-back packer assembly, plus the cost of two trips on each of the wells. In addition, ta catastrophic hazard (handling of the heavy drill collar) was removed from the overall process.

Benefits for using expandable liner hanger include the following:

a) Simplifies the operations by eliminating the need for conventional liner top-packers, thus reducing complexity
b) Improves reliability and fluid flow because it contains no moving parts.
c) Functions with a drill string assembly
d) Allows for the reciprocation and rotation of the liner during the cementing operations.
e) Provides sufficient seal integrity in a situation with a short drill pipe length because the liner top is set using hydraulic pressure for the expansion of the elastomeric elements.
f) Improves rig efficiency, and thus, reduces rig costs by helping the operator avoid costs of redundant conditioning trips.
g) Helps the operator manage capital expenditure by avoiding hanger damage or premature setting.

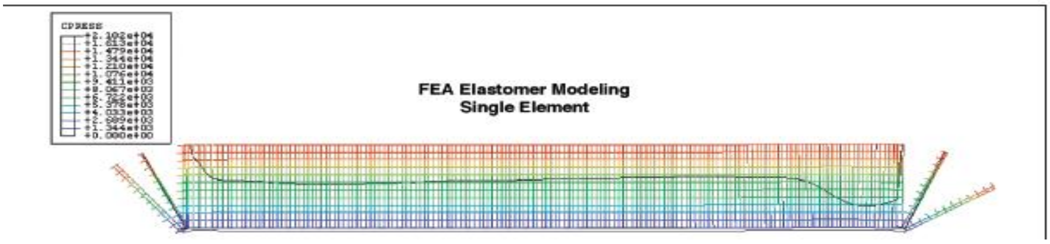


Figure 11 - Finite Element Analysis to Baseline the Expansion Pressure in the Elastomeric Bands

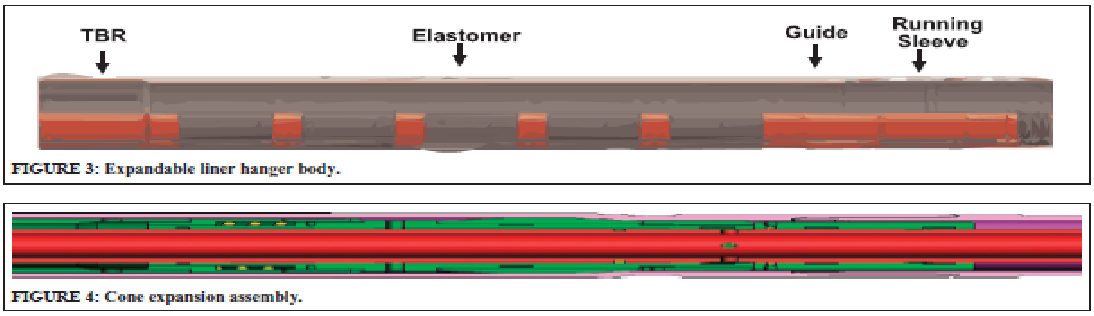


Figure 12 - Expandable Liner System Components

2.7.9. Expandable Liner Hanger Application in Arduous Well Conditions Improves Reliability: A Case History – SPE 88510

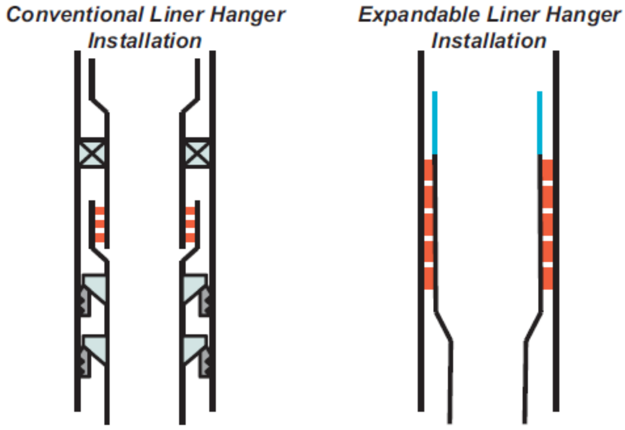


Figure 13 - Liner Top Completion

Well Information

a) 9-5/8 in. 53.5# casing set at 10,946ft
b) 9.7ppg water-based mud
c) Top of liner temperature:257^{O}F
d) Bottomhole static temperature: 305^{O}F
e) Top of liner: 10,869ft
f) 7-5/8 39# liner shoe to be set at 13,563ft
g) Buoyed weight of 96,531 lb
h) Kick off point of 12,600 ft
i) Top of cement at 12,050 ft
j) 10 degree / 100ft build angle to 50^{O}

The expandable liner hanger system proved to be a robust system capable of circumventing problems and allowing or development of liners in very different hole sections.

Drilling liners no longer require cement throughout the lap and above the liner top.

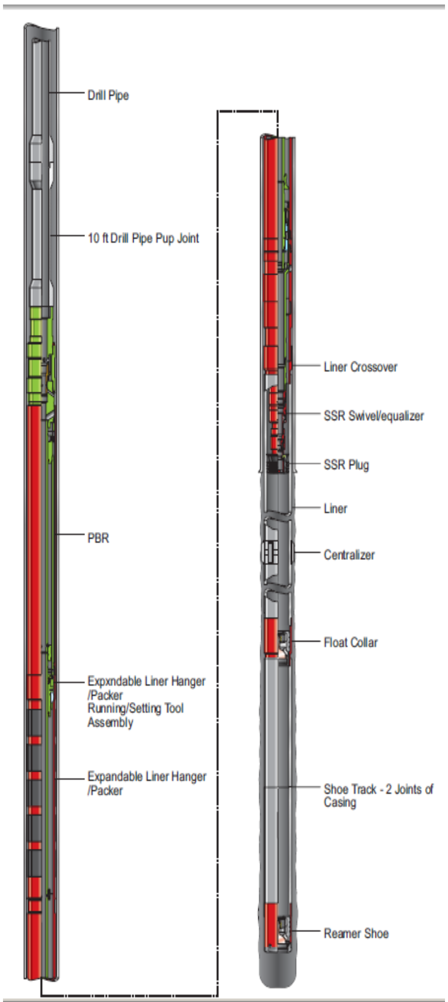


Figure 14 - Liner System Schematic

2.7.10. Baram Well Intervention PCSB SKO Sarawak & Drilling Division KLCC; Notice of Workover Operation Baram Alpha-22

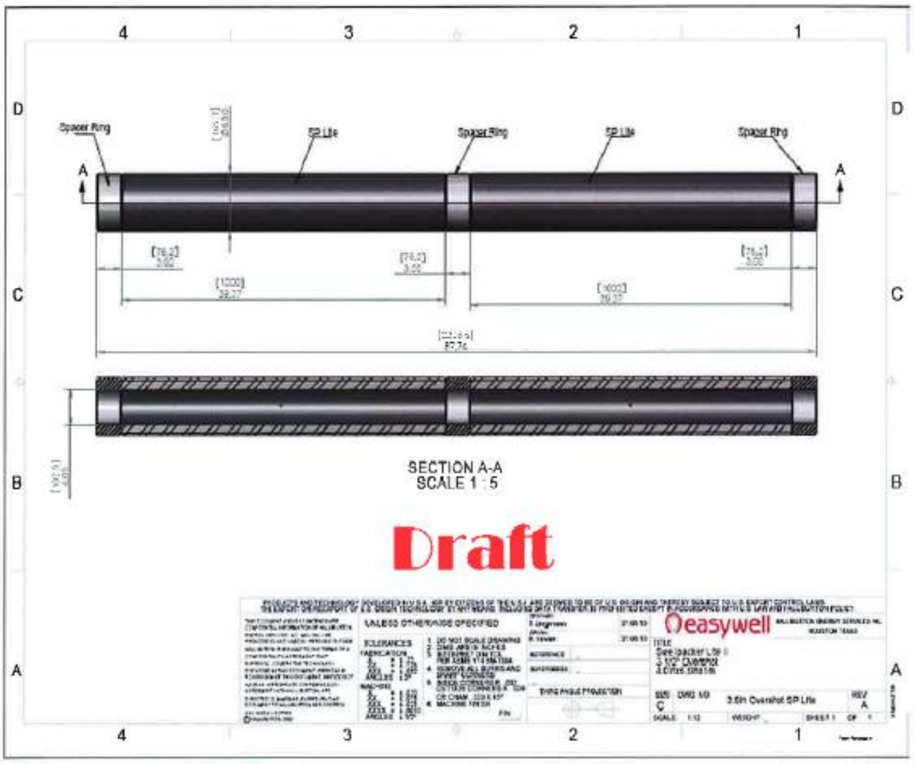


Figure 15 - EasyWell Swellpacker Test Fixture

BA-22R was re-completed in May 1991 as a selective dual string producer. The production casing size is 9-5/8” and the tubing size are 3-1/2” 9.2# L-80 New Vam and 2-7/8” L-80 NSCT. All zones were completed with IGP. Whereas for the production history, on March 2005, the SS has to be closed in due to Baram pipeline leak and for the LS, the sand producing intermittently with gross less than 50 bopd, 30% water cut and GOR of 6000scf/bl from Sept 2002 to Dec 2004.

This workover is expected to cure both SS and LS control line failure because due to the problems, LS has become idle started in 2002, and SS in 2009. The production from both string have never stabilized since then.

2.7.11. When Control Line Failed, What is the Alternative? West Malaysia Experience

Angsi experience proves that through tubing control line SCSSSV, if meticulously planned and well executed, is a viable application to rectify faulty CL. It is relatively cheaper which is about less than 5% than the workover cost, faster and easier to install compared to conventional workover. Also small foot print equipment compared to hydraulic workover unit, which is good for jacket (unmanned platform). Although WR-SCSSSV is an economical option compared to workover, there are a few disadvantages:

a) The internal diameter of the tubing is restricted, promoting significant risks of tubing leak due to erosion and extra pressure drop
b) The well is more susceptible to scale and asphaltene exposure and build-up.
c) For well intervention work, the WR-SCSSSV needs to be retrieved and re-set prior well flowback.

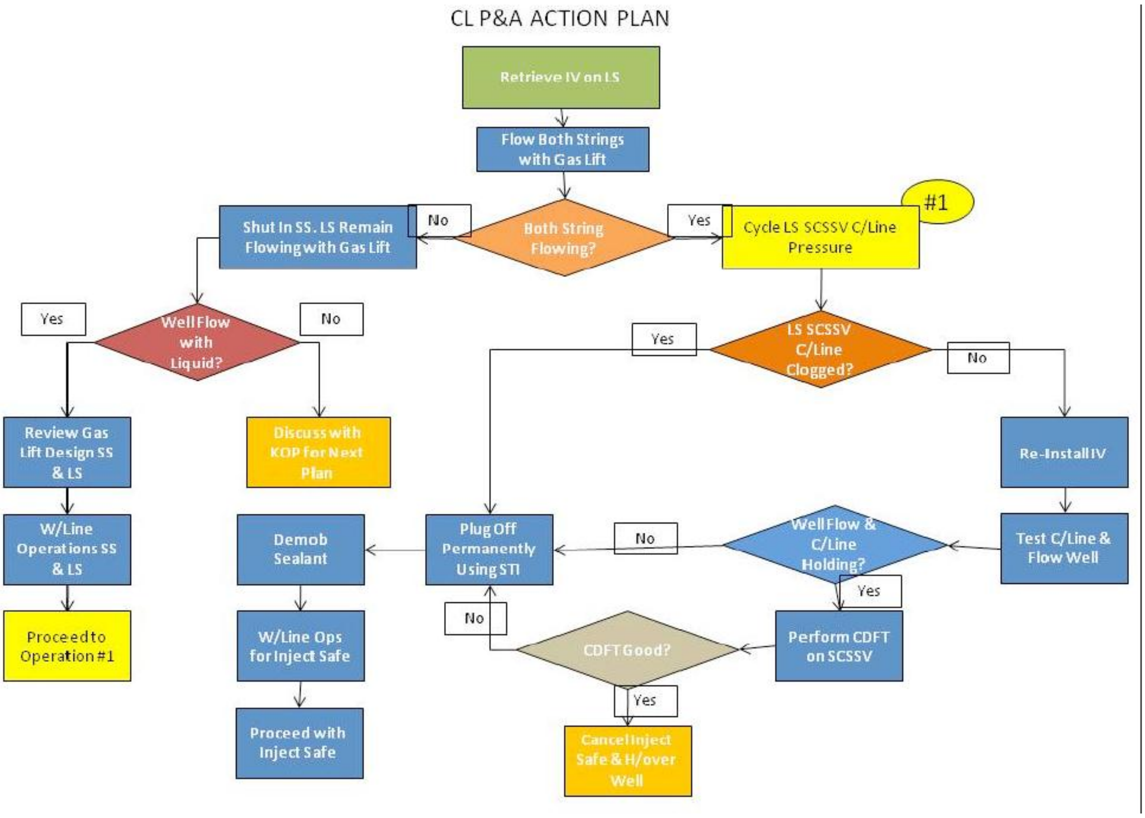


Chart 1- Plug & Abandoned (PNA) Flow Chart

Figure 16 - Actual Stinger & Receptacle Schematic

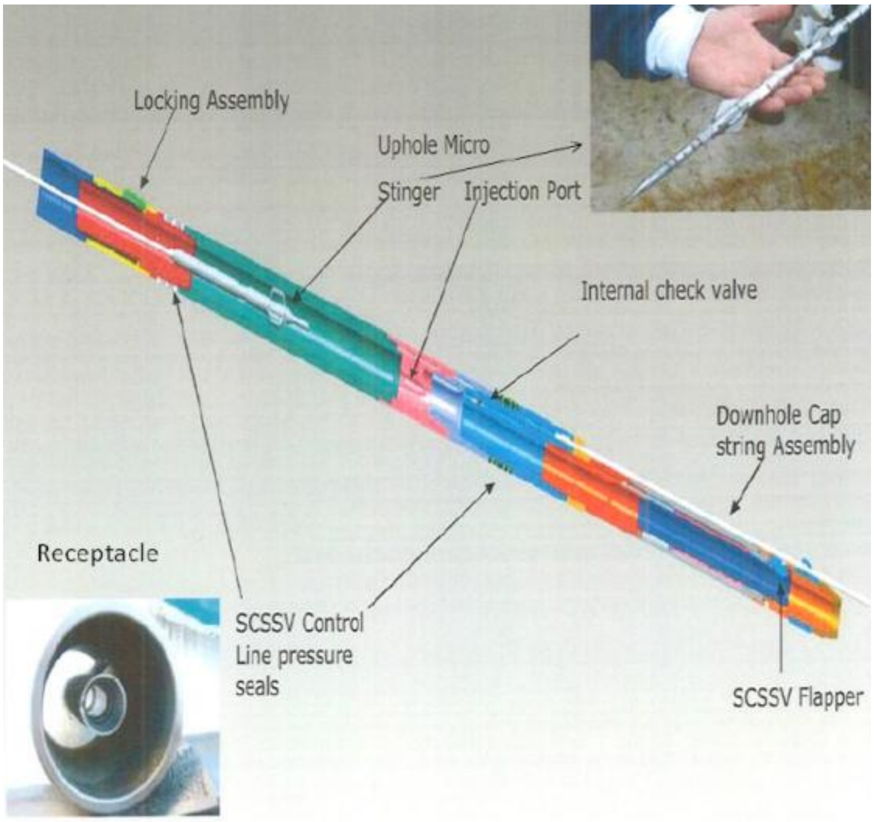


Figure 17 - S-IV (WR-SCSSSV) Conceptual Design

3. METHODOLOGY

Research and study have been done in order to test the parameters listed below for testing SEPs. Parameters tested are as below:-.

Model Parameter	Simulation Tested
Well Design	From Baram Alpha, Well-X data Profiling alteration based on Real Operation – X
Overshot Design	New mule shoe guide New workover method
SEPs Design	Maintenance Program (i.e. Tubing Evacuation, Tubing Leak, Production Shut-In, Frac Screen-Out, Tubing Overpull) Pressure Test 5000-9000psi High Injection Rate Pumping 50gpm-1000gpm

Table 2 - Project Parameters Tested

All the data gathered is from real operation data –X and for well profile is from one of Baram Alpha, Well-X. For this project, it includes two main processes which are mud preparation and mud testing.

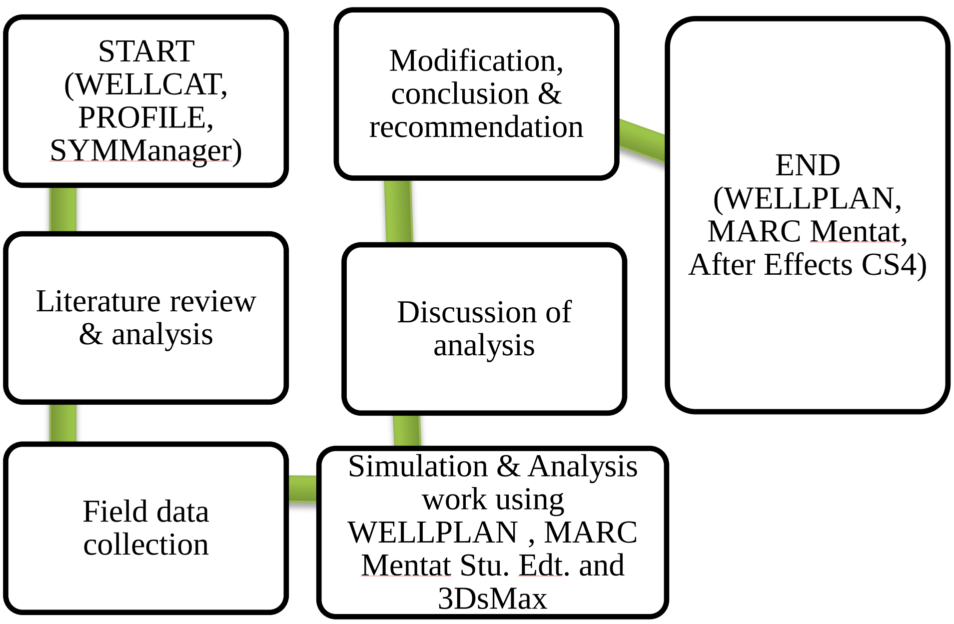
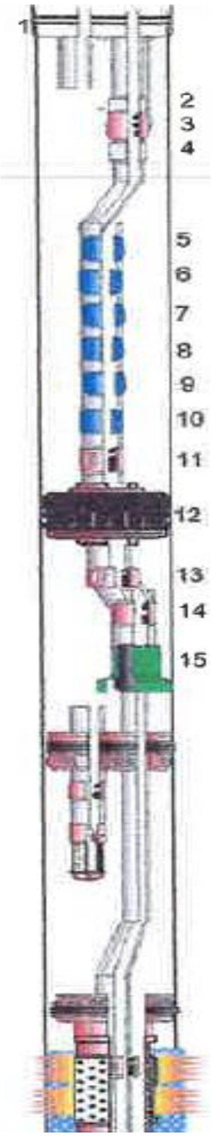


Chart 2 - Workflow Processes

1. Simulation using WELLCAT is done using data from a field.
2. Since WELLCAT does not have a module on finite element analysis of visco-elastic swellable rubber, more design and command of FEA was developed to be simulated in MARC Mentat and AE5 between the maximum swell force that can be applied to the efficiency of this tools.
3. Also quick comparison based on economic analysis between this pioneer-project method to the current methods.

3.1. Well Design



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Wellpath Editor

	Data-Entry Mode	MD (usft)	INC (°)	AZ (°)	TVD (usft)	DLS (°/100usft)	Max DLS (°/100usft)	Vsection (usft)	Departure (usft)
1	MD-INC-AZ	0.0	0.00	0.00	0.0			0.0	0.0
2	MD-TVD	127.0			127.0		0.00	0.0	0.0
3	MD-TVD	1127.0			1126.3		1.64	36.0	36.0
4	MD-TVD	2127.0			2078.0		2.02	343.1	343.1
5	MD-TVD	3127.0			2888.3		0.31	929.2	929.2
6	MD-TVD	4127.0			3595.7		0.57	1636.0	1636.0
7	MD-TVD	5127.0			4391.2		2.28	2241.9	2241.9
8	MD-TVD	6127.0			5329.8		1.87	2587.0	2587.0
9	MD-TVD	7128.0			6326.4		1.04	2680.3	2680.3
10	MD-TVD	8525.0			7723.3		0.00	2698.6	2698.6
11	MD-TVD	8577.0			8379.0		0.00	2698.6	2698.6

Deviation Profile

	MD (usft)	INC (°)	AZ (°)	TVD (usft)	DLS (°/100usft)	Max DLS (°/100usft)	Vsection (usft)	Departure (usft)
1	0.0	0.00	0.00	0.0	0.00	0.00	0.0	0.0
2	127.0			127.0		0.00	0.0	0.0
3	1127.0			1126.3		1.64	36.0	36.0
4	2127.0			2078.0		2.02	343.1	343.1
5	3127.0			2888.3		0.31	929.2	929.2
6	4127.0			3595.7		0.57	1636.0	1636.0
7	5127.0			4391.2		2.28	2241.9	2241.9
8	5791.9			5015.3		1.87	2471.4	2471.4
9	5831.0			5052.0		1.87	2484.8	2484.8
10	6127.0			5329.8		1.87	2587.0	2587.0
11	7128.0			6326.4		1.04	2680.3	2680.3
12	8043.0			7241.4		0.00	2692.3	2692.3
13	8525.0			7723.3		0.00	2698.6	2698.6
14	8577.0			8379.0		0.00	2698.6	2698.6

Section View

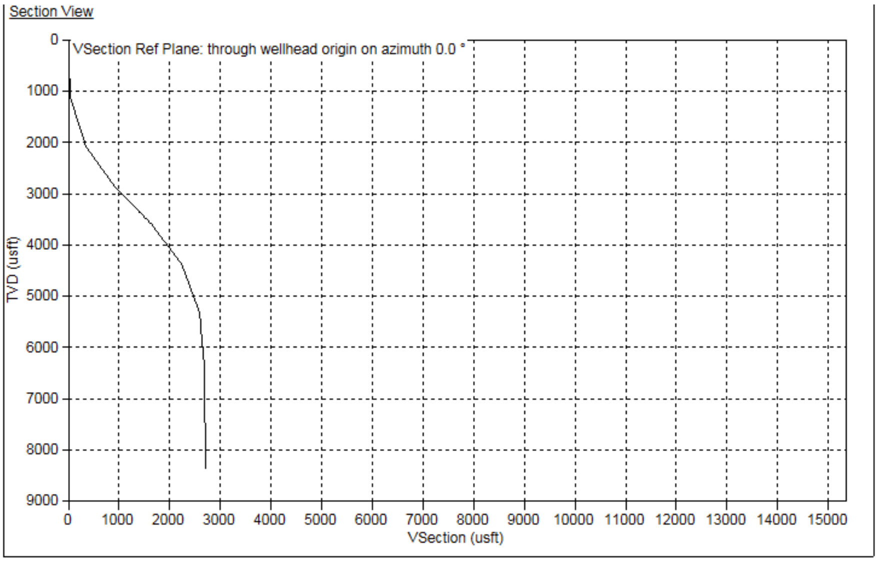


Figure 18 - Well X Profile Input WELLCAT Software

There are two wells data taken into account for this simulation. As a reason of these two wells share the same top-half-completion problems using (Landmark WELLCAT Software, 2012)

3.2. Overshot Design

After the well modelling is done, next parameter needed for modelling is the Overshot Inverted Swellable Elastomer Packer using (MARC Mentat Student Edition), (3DsMax), (After Effects CS4) & (Autodesk Inventor Pro)

1. Swelling properties of elastomer – Using MARC Mentat Student Edt.
2. Finite Element Analysis – Using MARC Mentat Student Edt.
3. High rate pumping pressure and stress analysis – Using 3DsMax
4. New workover method simulation –Using After Effects CS4
5. Design of Overshot Inverted SEPs BHA – Using Autodesk Inventor Pro
6. Mule shoe guide spring loaded new design – Using Autodesk Inventor Pro.

3.3. SEPs Design

The operations simulated to get parameters for this SEPs design are as follows:

1. Common maintenance program - Tubing Evacuation, Tubing Leak, Production Shut-In, Frac Screen-Out, Tubing Overpull
2. Production Shut-In, Frac Screen-Out, Tubing Overpull)
3. Pressure Test 5000-9000psi
4. High Injection Rate Pumping 50gpm-1000gpm

All of these operations are simulated using (Landmark WELLCAT Software, 2012). Fixed variables for these simulations are:

1. SEPs design (Length and size of BHA)
2. Depth of BHA
3. Well profiles (Temperature, Pressure, Deviation, etc.)

3.4. Project Activities and Key Milestones

Several targets have been set for the FYP I and FYP II. The schedule is as below:-

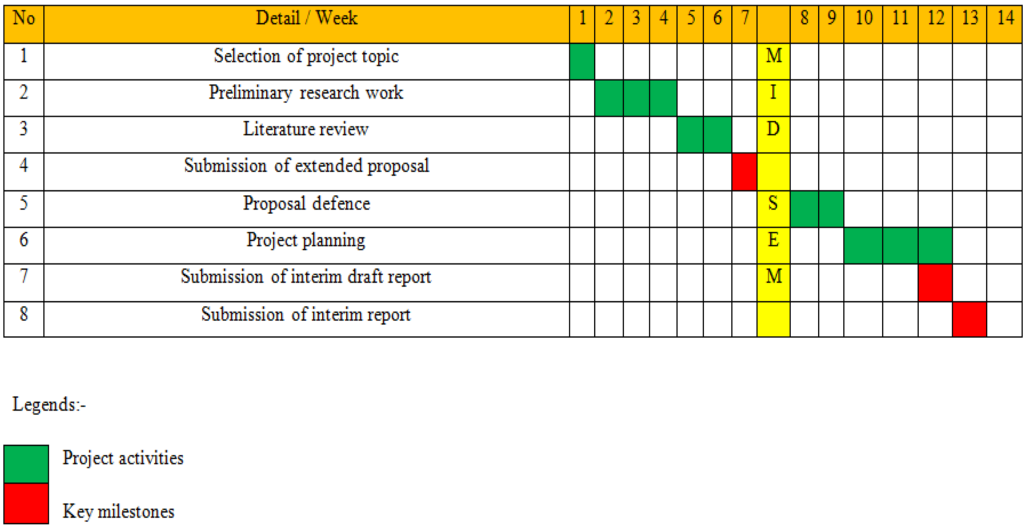


Figure 19 - Project Activities and Key Milestones for FYP I

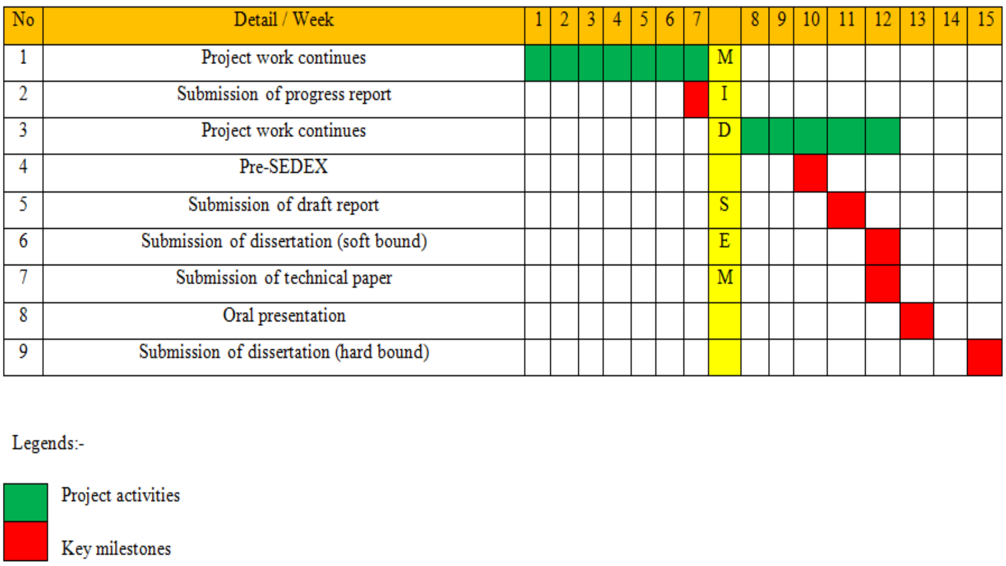


Figure 20 - Project Activities and Key Milestones for FYP II

4. RESULT AND DISCUSSION

This chapter will discuss about the outcome from the previous research conducted in earlier stage of the Inverted SEPs in one of the oil in PETRONAS Carigali Sarawak Operation (during Internship). As below, this part will include some of the test fixtures of the Inverted SEPs,design, cooking summary and pressure test summary. Overshot SEPs Testing Summary:

4.1 Overshot Design
4.2 Test Fixture Design
4.3 Cooking Summary
- Cooking Charts

4.4 Pressure Test Summary
- Pressure Charts

4.5 Pressure Test Simulation
- 5000psi – 9000psi

4.6 Maintenance Simulation
- Initial Conditions
- Production Shut-In
- Full Tubing Evacuation
- Tubing Leak
- Overpull while Running

4.7 High Rate Pumping Operation Simulation
- 50gpm – 1000gpm Diesel Pumping

4.8 Stress Analysis Simulation
- Tubing Stress Analysis
- Elastomer Stress Analysis

4.9 New Workover Method Simulation

4.1. Overshot Design

Based on the first Overshot Inverted SEPs tool installed in Baram Alpha Well – X, it appeared that the Dual String new completion fail to run as per discussed. Final well schematic **Expected** and **Executed** difference as below:

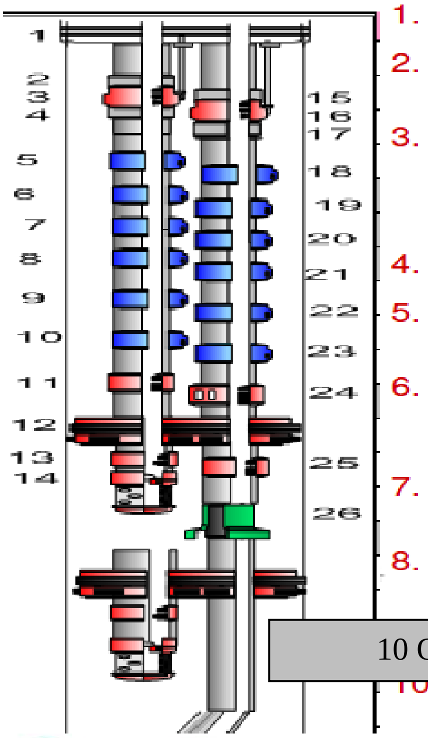
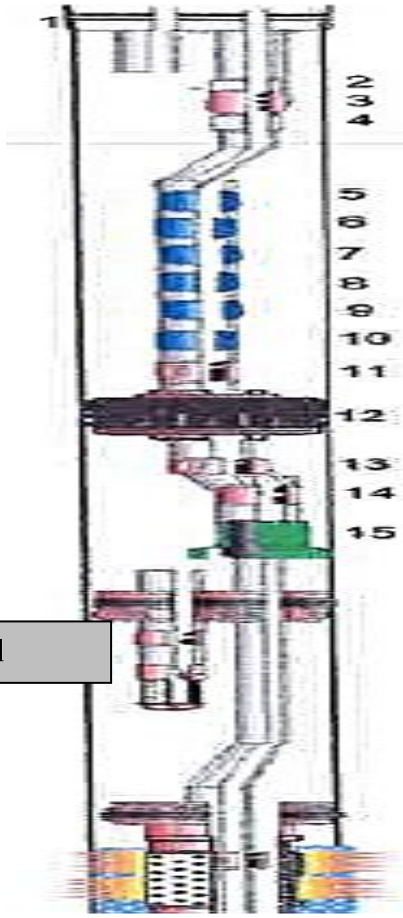
Expected	Executed
	

Table 3 - Expected & Executed Well Schematic

Based on the differences between Expected Final Completion and Executed Final Completion, lessons learnt from this miscalculation are as follows:

a) With dual string completion RIH, tubing hangar cannot be rotated and this situation will affect tubing stub swallow mechanism of the overshot Cut-Lip design.

b) 10- O1/1.5 Sand (Oil Production) has to be commingled with the LS production instead of Expected to be produced from new SS completion.

Figure 21 – Pioneer Overshot real scale view

Shown above the Cut-Lip Overshot type which has been used for Baram-Alpha Well – X. This pioneer combined technology has been failed to swallow existing LS tubing stub. Possibility of the failure mechanism is the tubing stub stuck at the sharp point of the Cut-Lip section

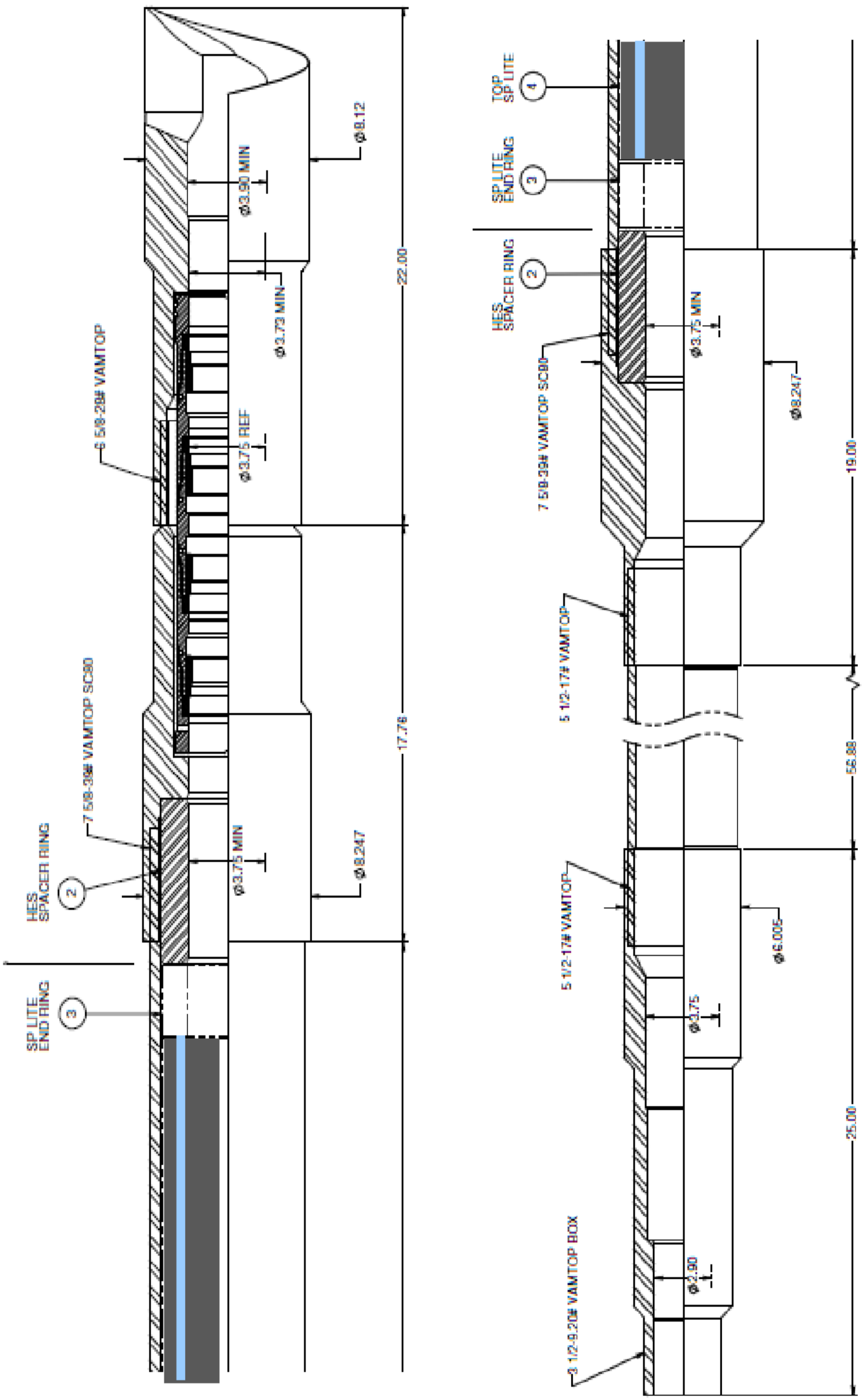


Figure 22 - Inverted Swellable Elastomer Packer c/w Overshot Pioneer Design

Research and simulation has been done by taking into account common overshot design that has been used widely throughout the global operation (i.e. fishing operation).

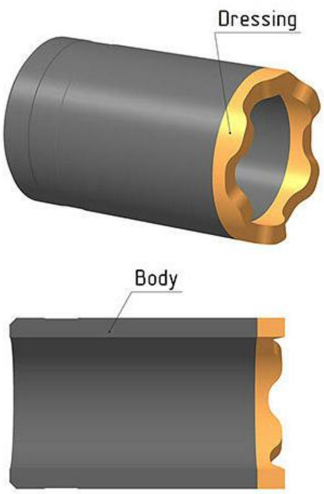
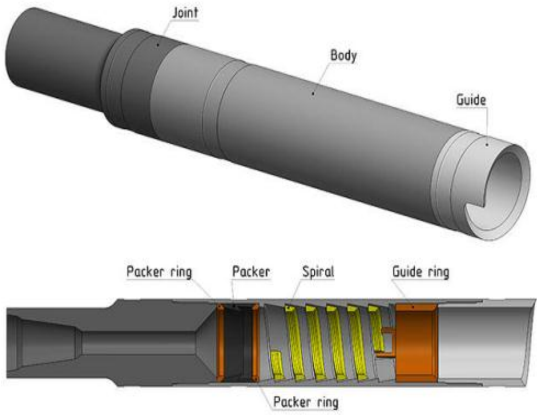
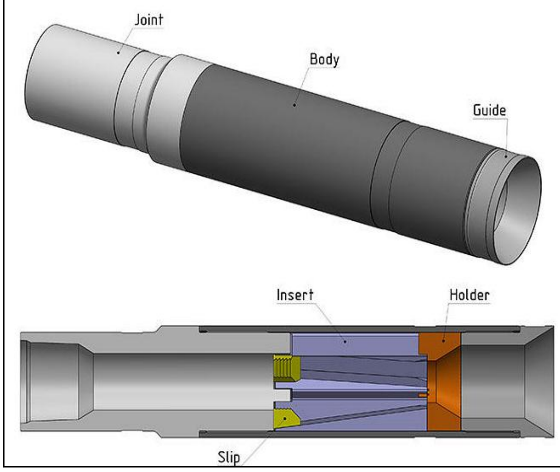
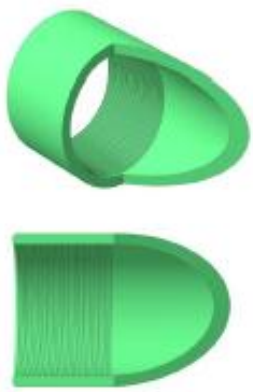
<table>
<tr><th>Wave-Like Washover Shoe</th><th>Cut-Lip Releasing Overshot</th></tr>
<tr><td>
</td><td>
</td></tr>
<tr><th>Catch-all Tapered Shoe Guide Fishing Tool</th><th>Half-Cut-Lip Overhsot Mule Shoe</th></tr>
<tr><td>
</td><td></td></tr>
</table>

Table 4 - Mule Shoe Guide Design by Bittekhnika Inc.

Final design based on this project to overcome the entire tubing latch-on problems is by using double tapered-mule-shoe-guide with vertical-motion part.

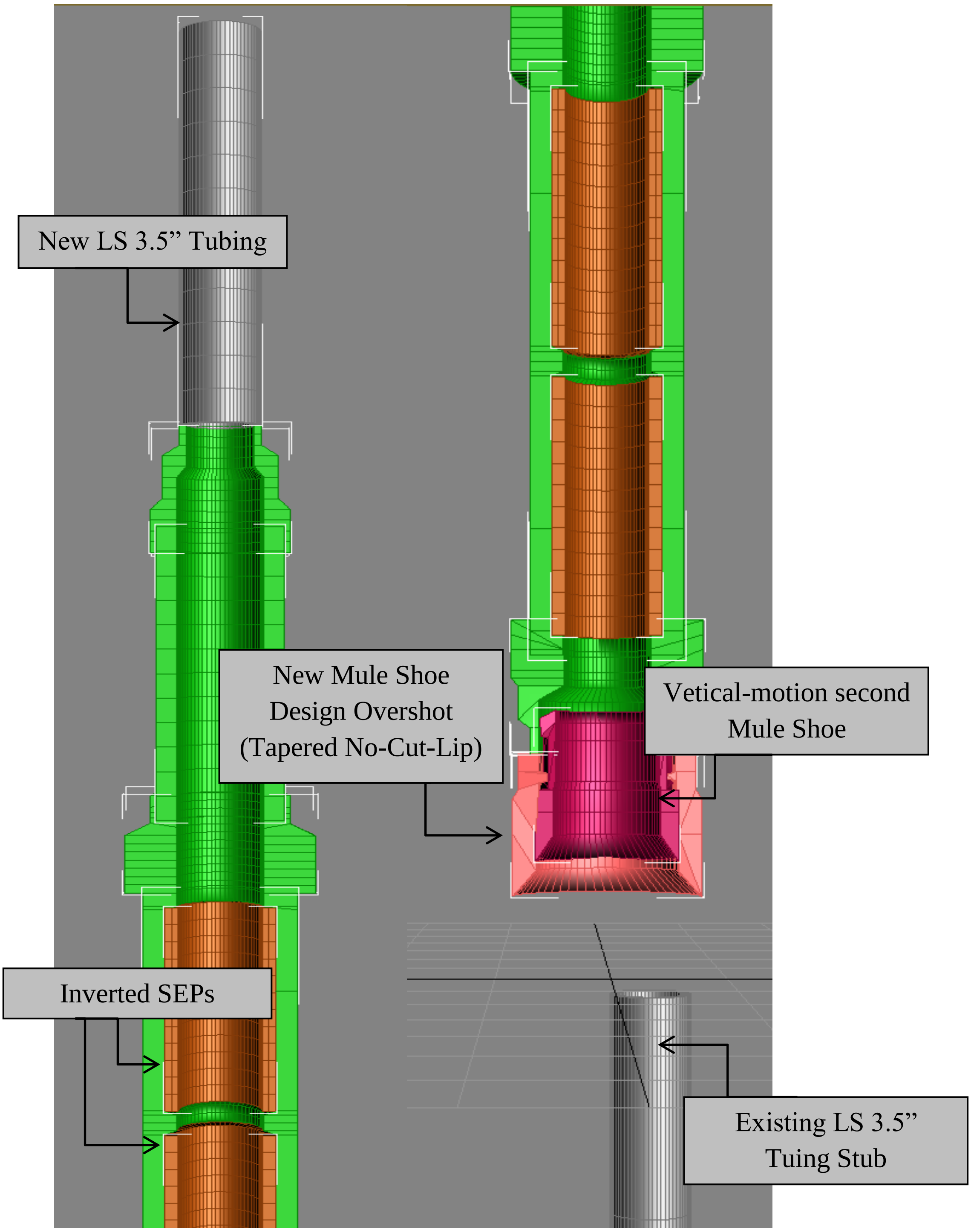


Figure 23 - New Overshot Inverted SEPs Design

For this new overshot design, simulations have been carried out to ensure better tubing stub latch-on mechanism.

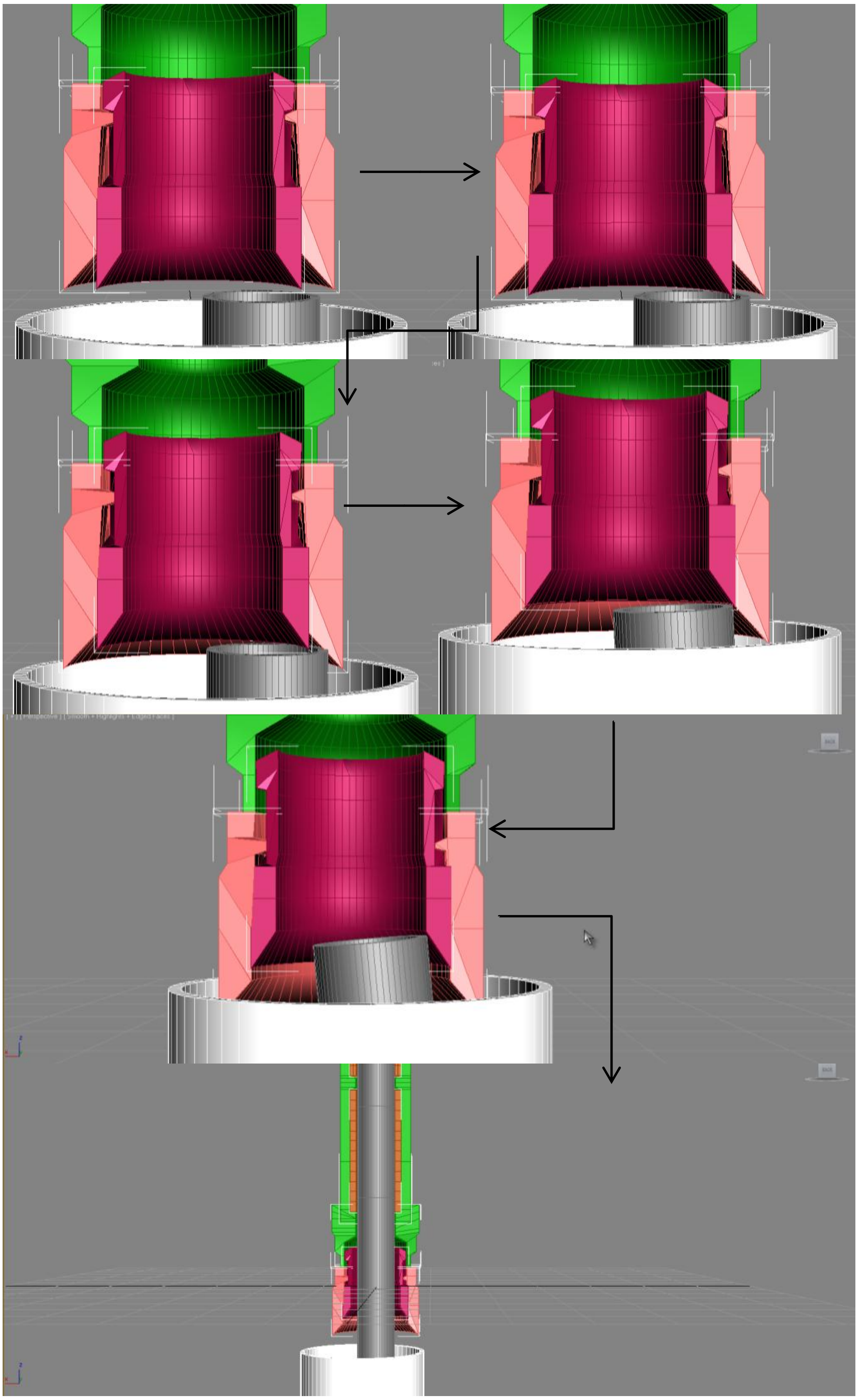


Figure 24 - New Overshot Inverted SEPs Latch-on Mechanism

4.2. Test Fixture Design

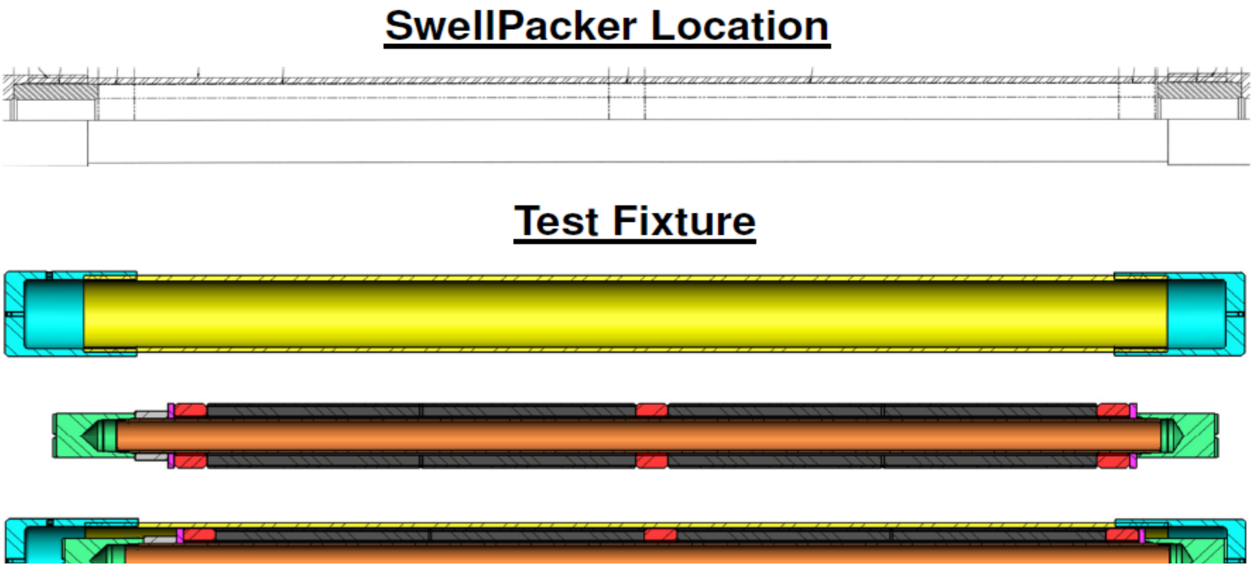


Figure 25 - Test Fixture Design

4.3. Cooking Summary (Cooking Charts)

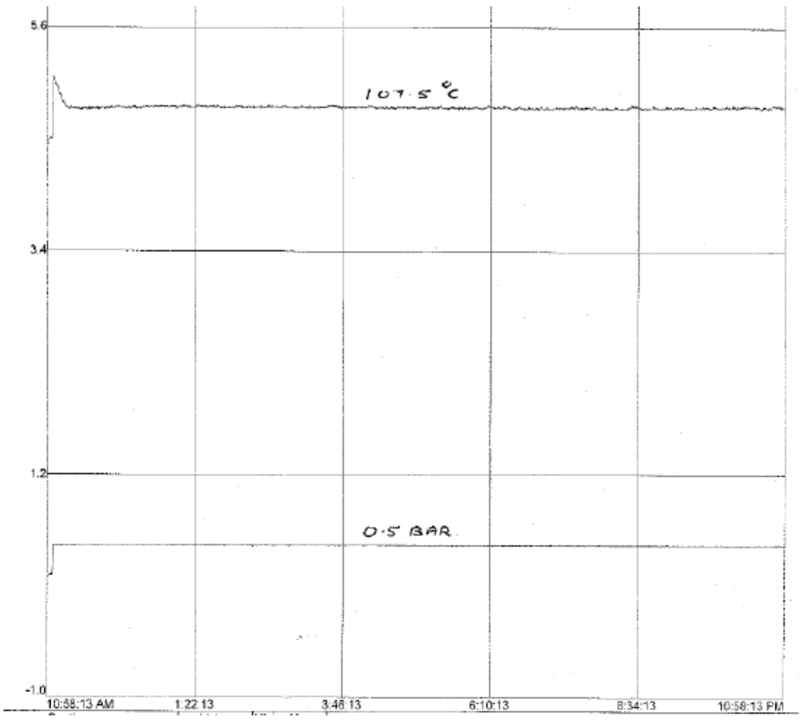


Chart 3 - Cooking Summary 1/2

- 3 days: 17th – 19th of March at 100°C - 48hrs cooking + 1hr cool down + 24 hrs cooking
- 1 day: 21st of March at 162 °C - 8 hrs cooked with production packers
- 2 days: 24th – 25th of March at 162 °C - 23 hrs cooking + 1 cool down + 23

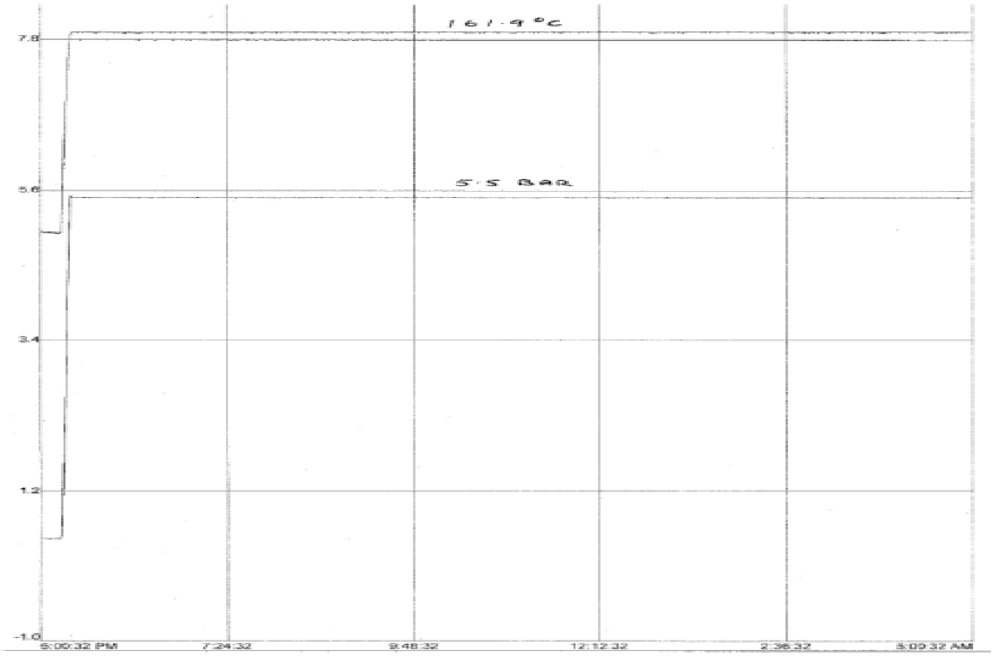


Chart 4 - Cooking Summary 2/2

Table 5 - SEPs Cooking Summary Table

Day	Temperature (°C)	Temperature (°F)	Pressure Exerted (bar)	Pressure Exerted (psi)	ID (in)	SEPs Length (in)	Surface Area (in²)	Force Exerted by 87.74" SEPs (lbf)
1	107.5	225.5	0.5	7.2519	3.5	87.74	1930.28	13998.19753
2	107.5	225.5	0.5	7.2519	3.5	87.74	1930.28	13998.19753
3	107.5	225.5	0.5	7.2519	3.5	87.74	1930.28	13998.19753
4	161.9	323.42	5.5	79.7709	3.5	87.74	1930.28	153980.1729
5	161.9	323.42	5.5	79.7709	3.5	87.74	1930.28	153980.1729
6	161.9	323.42	5.5	79.7709	3.5	87.74	1930.28	153980.1729

Testing at high temperature cooking T_{min} @ 225.5 °F which the Inverted SEP exerts 13,998.2 lbf nearly 14klbf. Whereas, for the T_{max} @ 323.42 °F, the Inverted SEP exerts up to 153,980.2 lbf, approx. 154klbf. T_{ave} for the well in simulation used is based on East Malaysia Geothermal Gradient ranging from 149.10 °F to 185.20 °F.

4.4. Pressure Test Summary (Pressure Charts)

- Day 1
  - Test 1 : After 3 cycles of 100 PSI it dropped to 34 PSI
  - Test 2 : After 3 cycles of 200 PSI it dropped to 185 PSI after 5 min

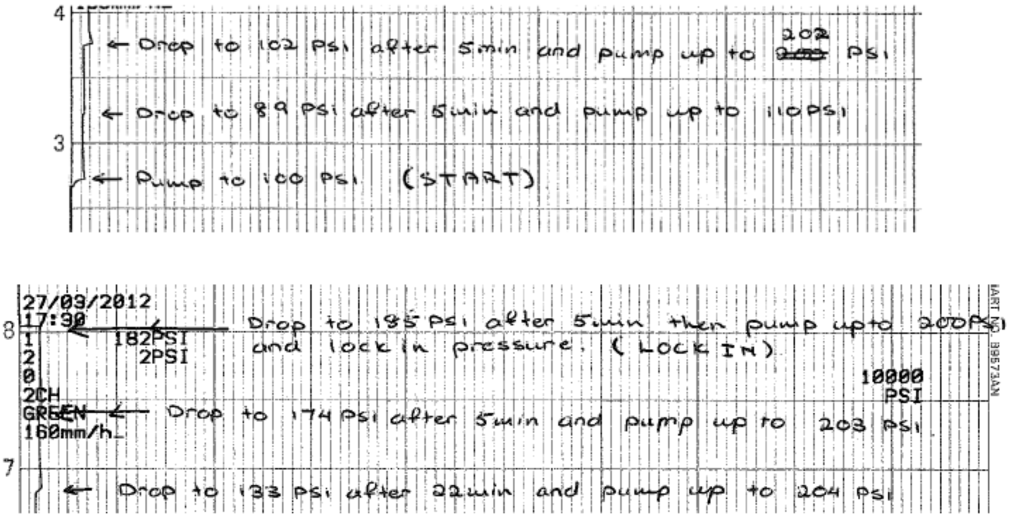


Chart 5 - Pressure Test 1/5

- Day 2
  - Test 1 : After 3 cycles of 200 PSI it dropped to 183 PSI after 5 min
  - Test 2 : After 3 cycles of 500 PSI it dropped to 496 PSI after 5 min
  - Test 3 : During lock in pressure increased to 502 PSI
    : After 2 cycles of 600 PSI pressure held
    : Pumped to 800 PSI and dropped to 747 PSI after 1hr 15min
  - Test 4 : Pumped to 1000 PSI and dropped to 853 PSI after 1hr
  - Test 5 : After 3 cycles of 1000 PSI it dropped to 982 PSI after 15 min

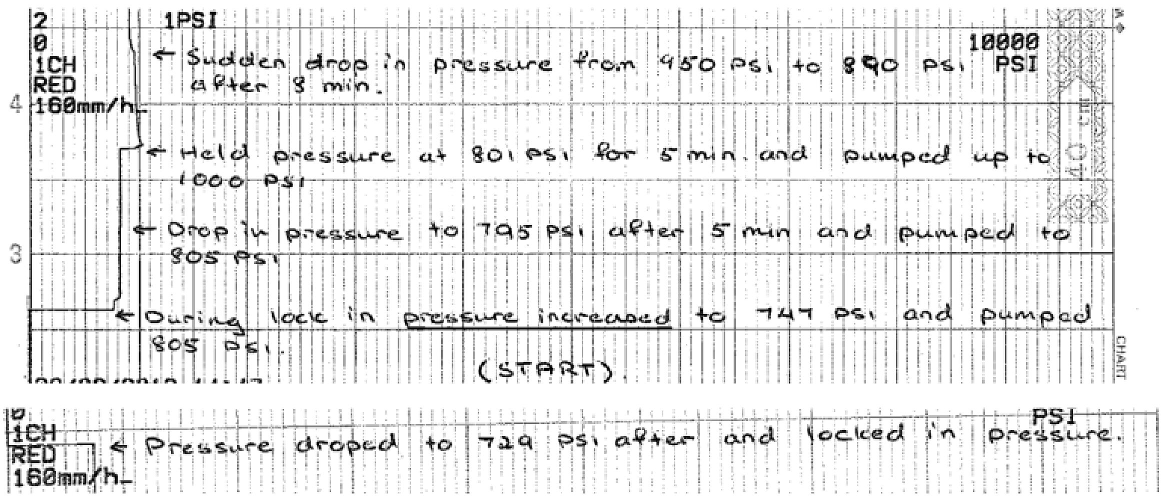


Chart 6 - Pressure Test 2/5

- Day 3
  - Test 1 : After 2 cycles of 1200 PSI it dropped to 1174 PSI after 5min
    : Pumped to 15000 PSI and dropped to 1460 PSI after 1 hr
  - Test 2 : Pumped to 1540 PSI and dropped to 1512 PSI after 8 min
    : After 3 cycles of 2000 PSI it dropped to 1908 PSI after 5 min
    : Lock in pressure at 2020 PSI it dropped to 1908 PSI after 1.5 hr
  - Test 3 : After 3 cycles of 2350 PSI pressure dropped to 2227 PSI after 5 min

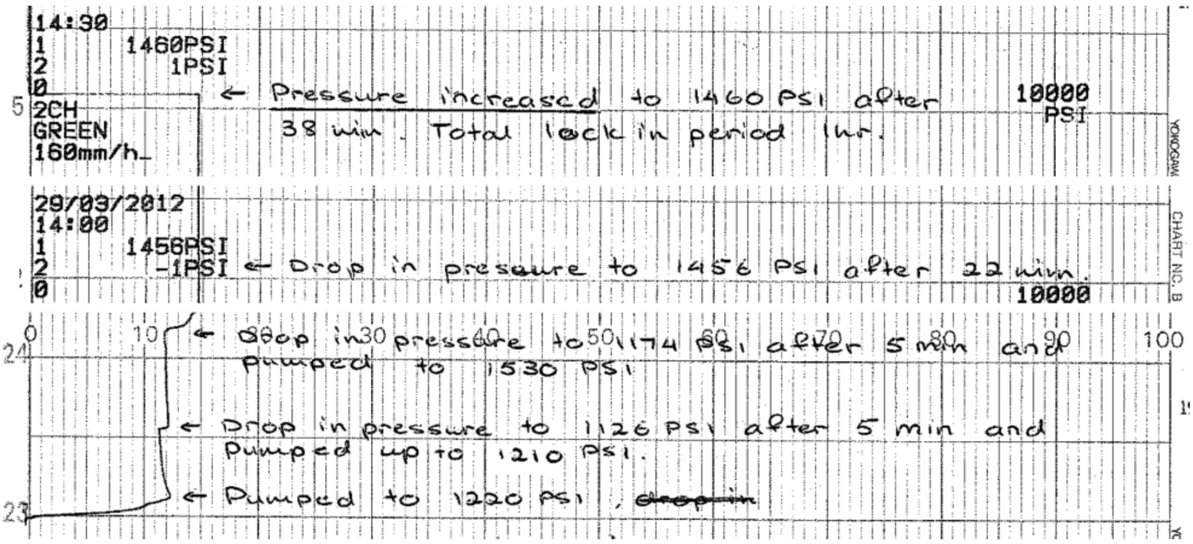


Chart 7 - Pressure Test 3/5

- Day 4
  - Test 1 : Pressure dropped to 1600 PSI from initial pressure of 2400 PSI
    : Pressure increased to 2052 after 6 hrs

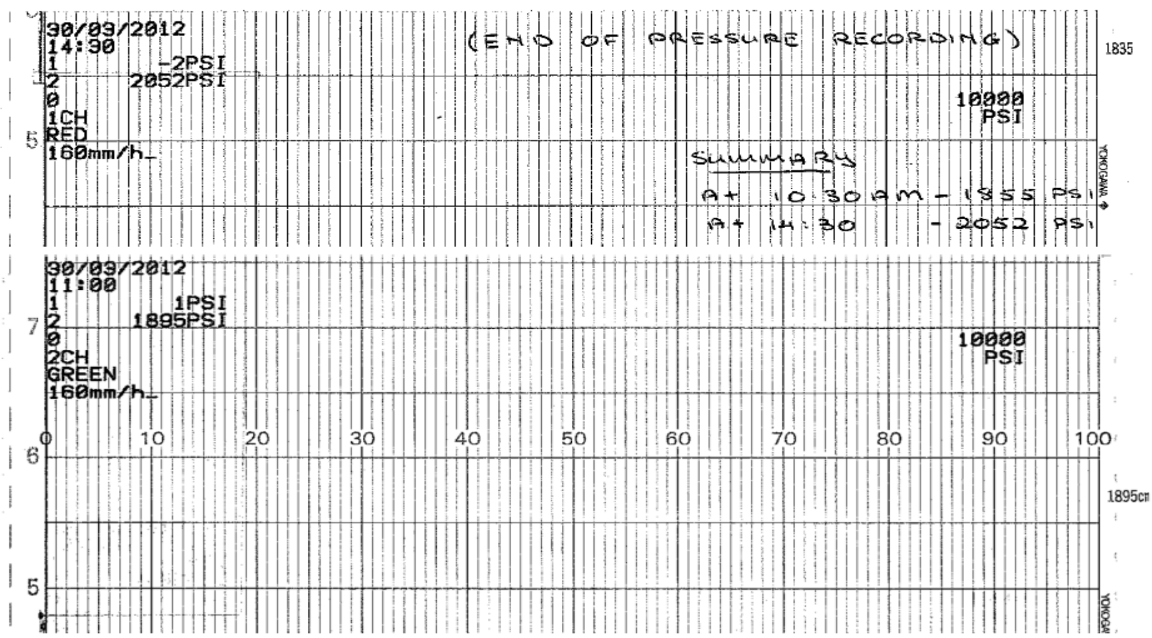


Chart 8 - Pressure Test 4/5

- Day 5
  - Test 1 : After 3 cycles of 2400 PSI and lock in pressure dropped to as low as 2335 PSI and increased to 2500 PSI.

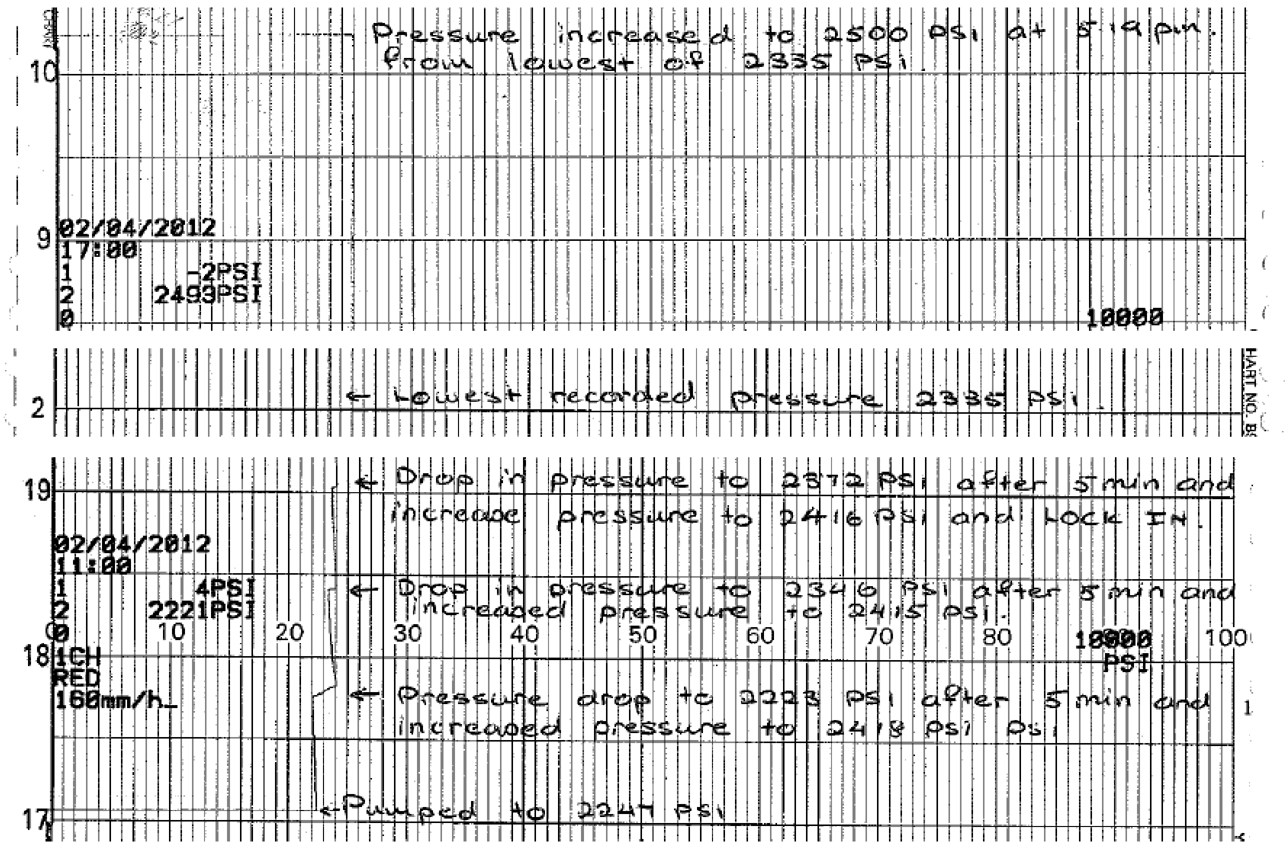
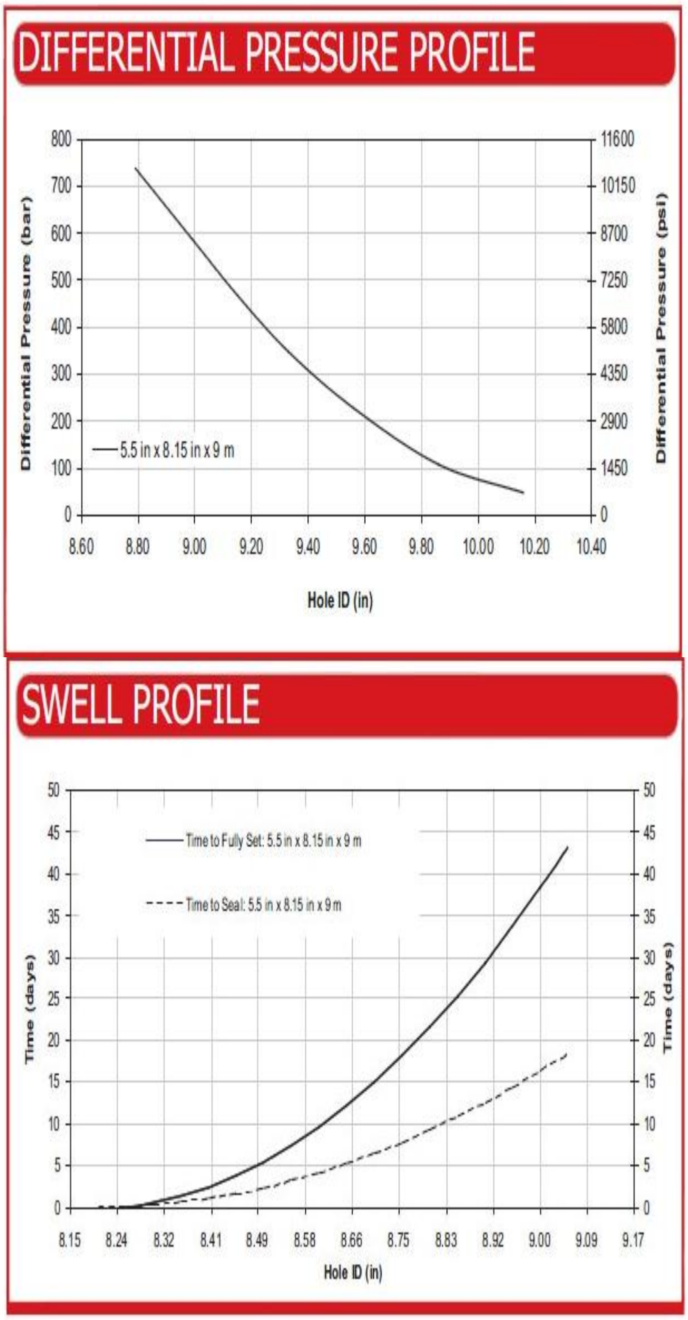


Chart 9 - Pressure Test 5/5

Pressure test simulation in 2011 before the pioneer tool of Overshot Inverted SEPs is installed by using SwellSim© software of EASYWELL. Input as follows:

Downhole Input	Tool Input
Fluid Viscosity : 1cP	Pipe OD : 7in
Temp @ Packer Depth : 80^{o}C / 176^{o}F	Packer OD : 8.15in
Required ΔP : 75bar / 1087.785psi	Element Length : 3m

Table 6 - SwellSim Data Input



Graph 2 - SwellSim Data Output

4.5. Pressure Test Simulation

Using WELLCAT Software as input and results below:

File: 22_Top_Half_Completion_Only — Date/Time: November 23, 2012 10:25:18 PM Page: 7 of 15

Loads Data - 5000PSI Pressure Test - 3-1/2 " Production Tubing

3-1/2 " Production Tubing	
Type :	Pressure Test
Pump Pressure :	5000.00 psi
Fluid Inside Tubing :	Diesel Oil
Plug Depth :	5900.0 usft
Annulus	
Wellhead Pressure :	188.00 psi

Figure 26 – Pressure Test Input (WELLCAT)

Variable manipulated through this simulation part is the Pump Pressure: - 5000, 5500, 6000, 6500, 7000, 7500, 8000, 8500 and 9000psi. The result is calculated as below.

Tubing Load Summary - 5000PSI Pressure Test 3-1/2 " Production Tubing

	String Section	MD (usft)	Axial Force (lbf)	Dogleg (°/100usft)	Torque (ft-lbf)	Friction Force (lbf/ft)	Temperature (°F)	Pressure (psi) Internal	Pressure (psi) External
1	1	5792.0	51819	1.87	0.0	0.0	149.10	6823.73	188.04
2	1	5819.9	51560	1.87	0.0	0.0	149.69	6833.27	200.51
3	1	5820.1	48785	1.87	0.0	0.0	149.70	6833.33	2600.15
4	1	5830.9	48684	1.87	0.0	0.0	149.93	6837.02	2604.97

Packer Load Summary - 5000PSI Pressure Test 3-1/2 " Production Tubing

	Name	Packer MD (usft)	Setting Sequence	Tubing String	Tubing-to-Packer Force	Axial Load Above (lbf)	Axial Load Below (lbf)	Annulus Pressure Above (psi)	Annulus Pressure Below (psi)	Temperature	Latching Force (lbf)	Packer-to-Casing Force
1	Packer #11 (Pac	5820.0	1	3-1/2 " Productio	-2775	51560	48785	200.51	2600.15	149.69	69260	-6191
2												
3	Negative forces are in the upward direction.											

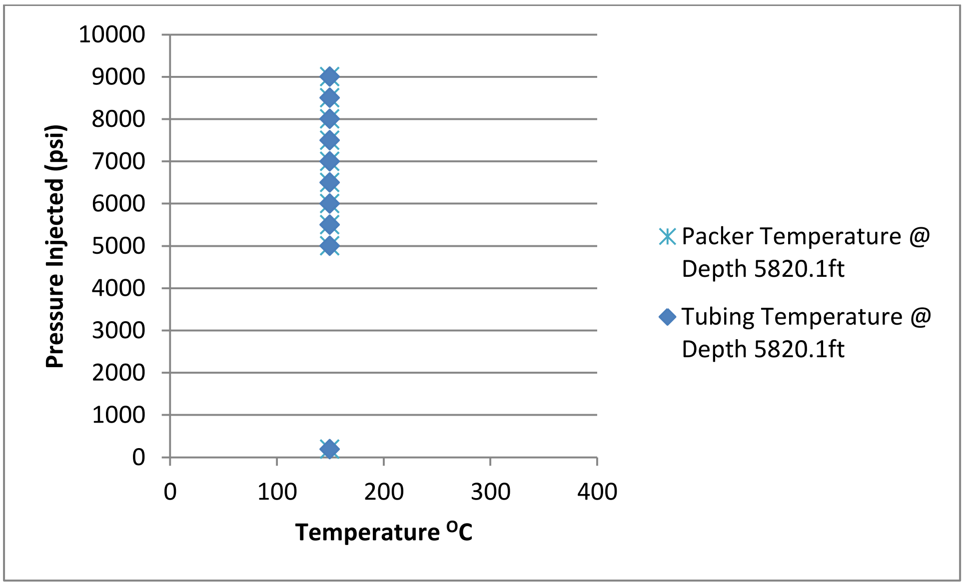


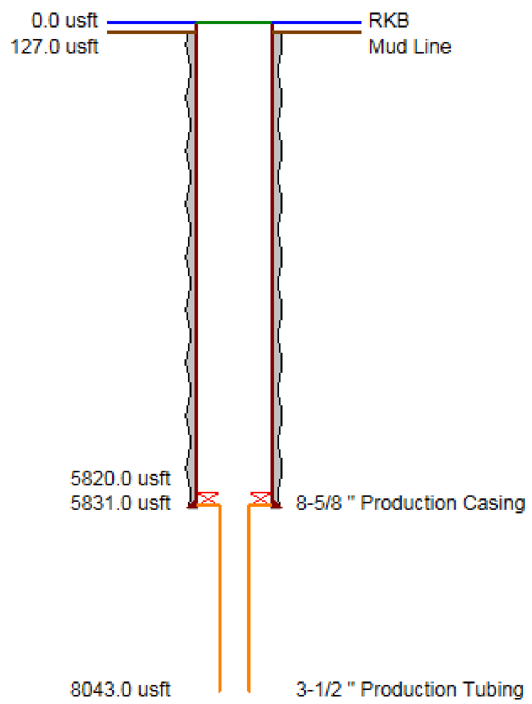
Chart 10 - Pressure Injected vs Temperature

And from the result charted above, it shows that tubing and packer temperature is unaffected by FTHP variation. This can be confirmed that, for post-job maintenance program (i.e. FBUS, FGS) the section where Overshot Inverted SEPs installed would give normal temperature distribution.

4.6. Maintenance Simulation

Using WELLCAT Software as input and results below:

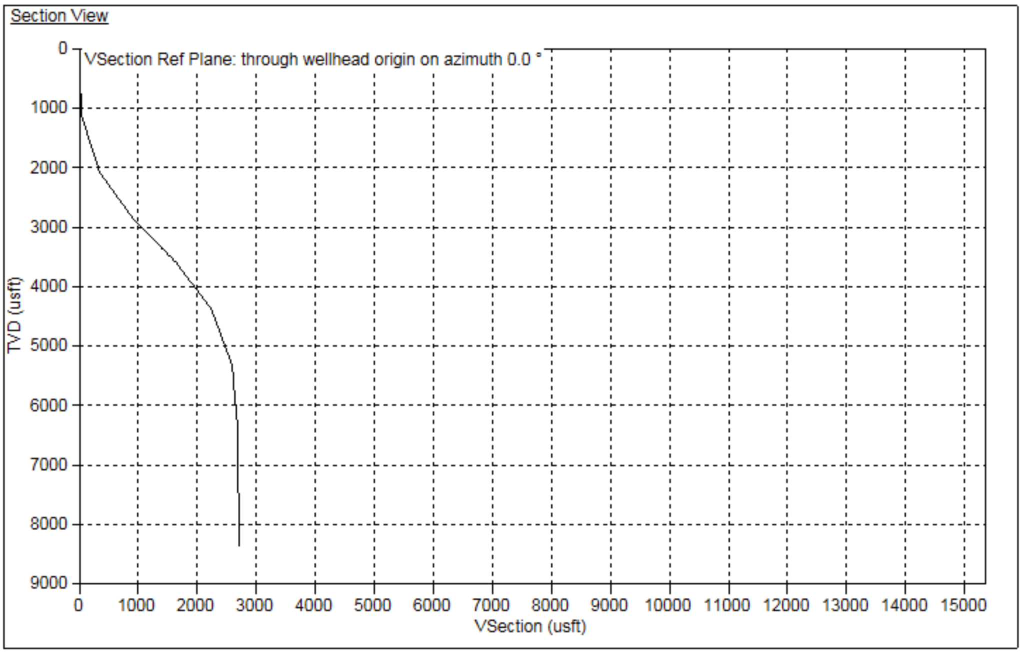
Well Schematic



	Data-Entry Mode	MD (usft)	INC (°)	AZ (°)	TVD (usft)	DLS (°/100usft)	Max DLS (°/100usft)	Vsection (usft)	Departure (usft)
1	MD-INC-AZ	0.0	0.00	0.00	0.0			0.0	0.0
2	MD-TVD	127.0			127.0		0.00	0.0	0.0
3	MD-TVD	1127.0			1126.3		1.64	36.0	36.0
4	MD-TVD	2127.0			2078.0		2.02	343.1	343.1
5	MD-TVD	3127.0			2888.3		0.31	929.2	929.2
6	MD-TVD	4127.0			3595.7		0.57	1636.0	1636.0
7	MD-TVD	5127.0			4391.2		2.28	2241.9	2241.9
8	MD-TVD	6127.0			5329.8		1.87	2587.0	2587.0
9	MD-TVD	7128.0			6326.4		1.04	2680.3	2680.3
10	MD-TVD	8525.0			7723.3		0.00	2698.6	2698.6
11	MD-TVD	8577.0			8379.0		0.00	2698.6	2698.6

Deviation Profile

	MD (usft)	INC (°)	AZ (°)	TVD (usft)	DLS (°/100usft)	Max DLS (°/100usft)	Vsection (usft)	Departure (usft)
1	0.0	0.00	0.00	0.0	0.00	0.00	0.0	0.0
2	127.0			127.0		0.00	0.0	0.0
3	1127.0			1126.3		1.64	36.0	36.0
4	2127.0			2078.0		2.02	343.1	343.1
5	3127.0			2888.3		0.31	929.2	929.2
6	4127.0			3595.7		0.57	1636.0	1636.0
7	5127.0			4391.2		2.28	2241.9	2241.9
8	5791.9			5015.3		1.87	2471.4	2471.4
9	5831.0			5052.0		1.87	2484.8	2484.8
10	6127.0			5329.8		1.87	2587.0	2587.0
11	7128.0			6326.4		1.04	2680.3	2680.3
12	8043.0			7241.4		0.00	2692.3	2692.3
13	8525.0			7723.3		0.00	2698.6	2698.6
14	8577.0			8379.0		0.00	2698.6	2698.6



File: 22_Top_Half_Completion_Only — Date/Time: November 22, 2012 07:07:08 PM Page: 7 of 13

Loads Data - Production Shut-In - 3-1/2 " Production Tubing

3-1/2 " Production Tubing	
Type :	Shut-In
Pressure :	250.00 psi
Location :	Wellhead
Operation or Load :	Initial Conditions
Tubing Fluid Density Profile :	From Initial Conditions
Annulus	
Wellhead Pressure :	331.00 psi

Loads Data - Full Evac - 3-1/2 " Production Tubing

3-1/2 " Production Tubing	
Type :	Tubing Evacuation
Operation or Load :	Initial Conditions
Annulus	
Wellhead Pressure :	0.00 psi

Loads Data - Tubing Leak - 3-1/2 " Production Tubing

3-1/2 " Production Tubing	
Type :	Tubing Leak
Operation or Load :	Production Shut-In
Annulus	
Wellhead Pressure :	3485.05 psi

Loads Data - Overpull While Running - 3-1/2 " Production Tubing

3-1/2 " Production Tubing	
Type :	Overpull
Overpull Force :	20000 lbf
Running Fluid :	Diesel Oil

Figure 27 - Maintenance Program Load Input (WELLCAT)

As this is a new design, there is no such simulation in WELLCAT® that can design the inverted simulation, so the casing in this profiler is meant to be the overshot whereas tubing below is the tubing stub hold by the packer. Design analysis result is calculated as below. As per result, every maintenance operation simulated still maintaining the BHA also the tubing stub in their safety ratings.

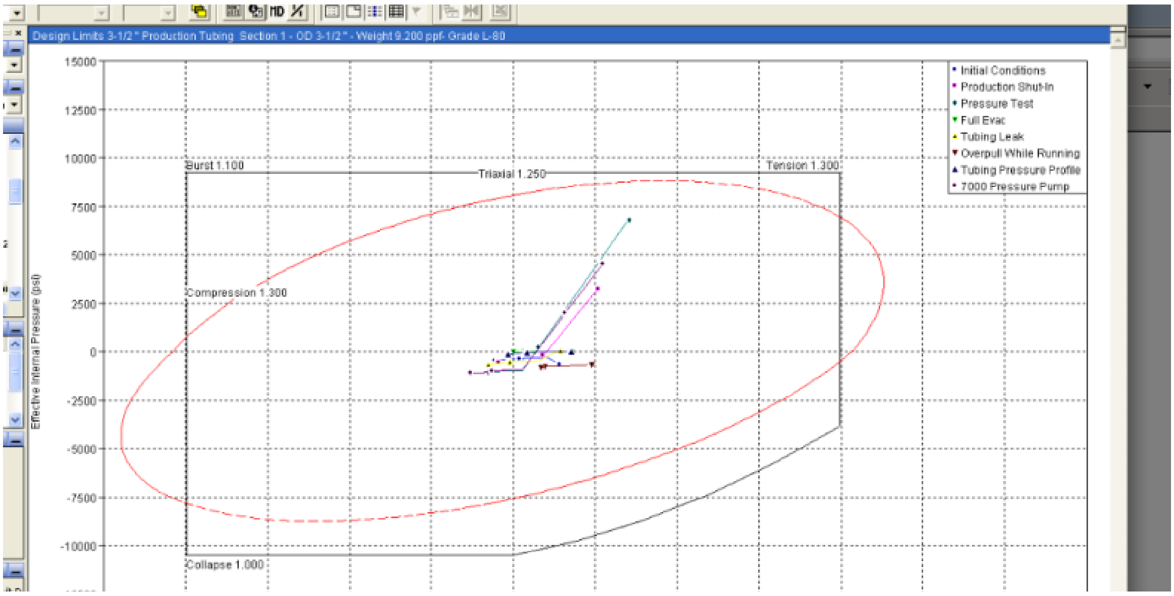


Figure 28 - Design Limits Factor (WELLCAT)

4.7. High rate Pumping Operation Simulation

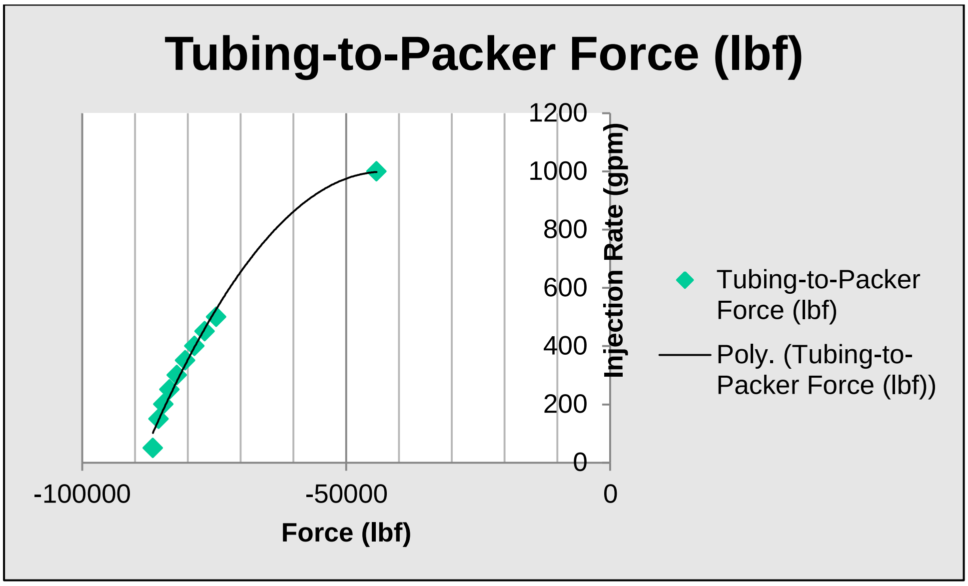
For this high rate operation, a thorough analysis is made based on Diesel Injection operation, at fixed Pump Pressure of 5000 psi, to execute analysis for thermal contraction and anchoring forces acting on the tube and packer - altering the Injection rate as table below:

Pump Pressure	Injected Fluid	Rate of Injection	FTHP	Tube Temp @ 5819'	Packer Temp @ 5819'	Tubing-to-Packer Force (lbf)	Latching force (lbf)
5000	Diesel	50	188	84.29	84.29	-86607	105126
5000	Diesel	150	188	83.99	83.99	-85524	104152
5000	Diesel	200	188	84.39	84.39	-84599	103311

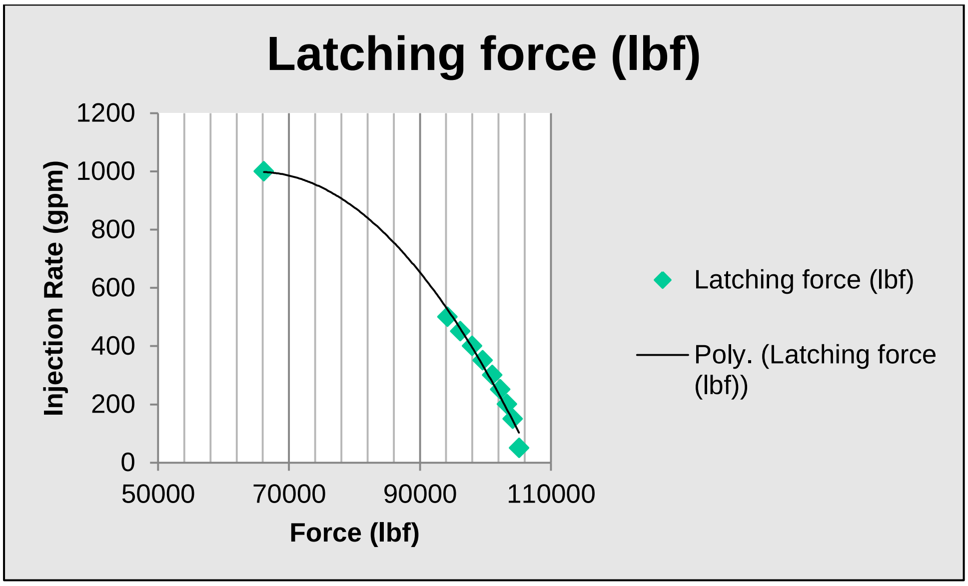
5000	Diesel	250	188	84.99	84.99	-83451	102266
5000	Diesel	300	188	85.79	85.79	-82086	101020
5000	Diesel	350	188	86.69	86.69	-80509	99580
5000	Diesel	400	188	87.79	87.79	-78728	97948
5000	Diesel	450	188	88.99	88.99	-76772	96158
5000	Diesel	500	188	90.29	90.29	-74647	94211
5000	Diesel	1000	188	110.29	110.29	-44246	66159

Table 7 - High Rate Pumping Simulation Input

The results are as follows:



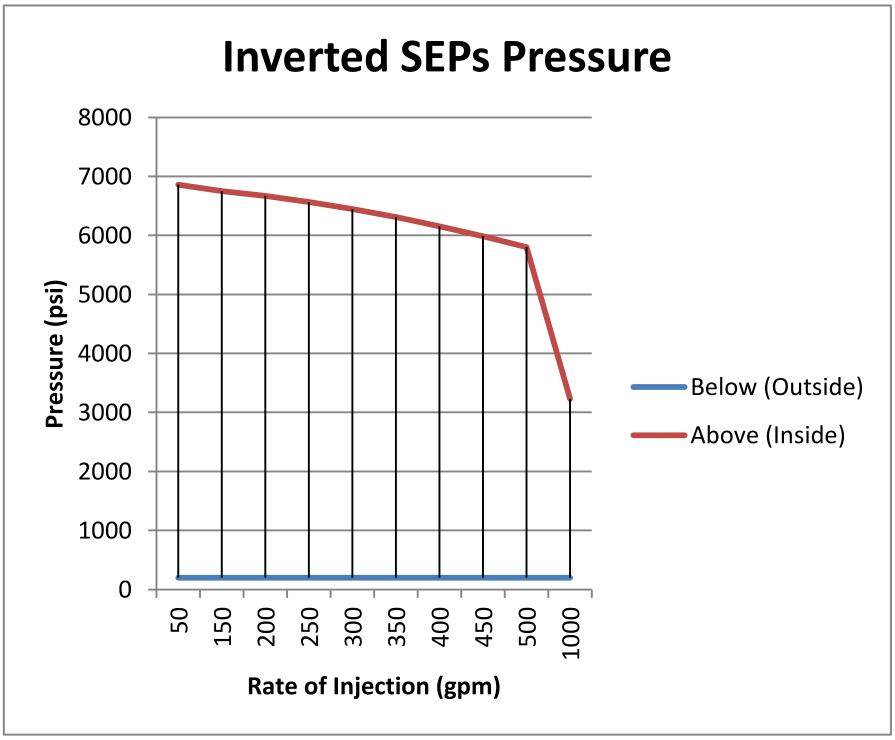
Graph 3 – Injection rate vs Tubing-to-Packer Force (lbf)



Graph 4 – Injection rate vs Latching Force (lbf)

DeltaP @ 5819.9ft					
5000psi @ Rate of Injection (gpm)	Tubing Pressure (psi)		Inverted SEPs Pressure (psi)		
	Internal	External	Below (Outside)	Above (Inside)	**ΔP (psi)**
50	6860.27	200.51	200.51	6860.33	**6659.82**
150	6752.47	200.51	200.51	6752.53	**6552.02**
200	6668.27	200.51	200.51	6668.33	**6467.82**
250	6565.77	200.51	200.51	6565.83	**6365.32**
300	6445.8	200.51	200.51	6445.73	**6245.22**
350	6308.68	200.51	200.51	6308.72	**6108.21**
400	6155.48	200.51	200.51	6155.52	**5955.01**
450	5986.78	200.51	200.51	5986.82	**5786.31**
500	5802.89	200.51	200.51	5802.91	**5602.4**
1000	3230.63	200.5	200.51	3230.57	**3030.06**

Table 8 - Pressure Differential Table at SEPs Depth



Graph 5 - Inverted SEPs Pressure vs Injection Rate

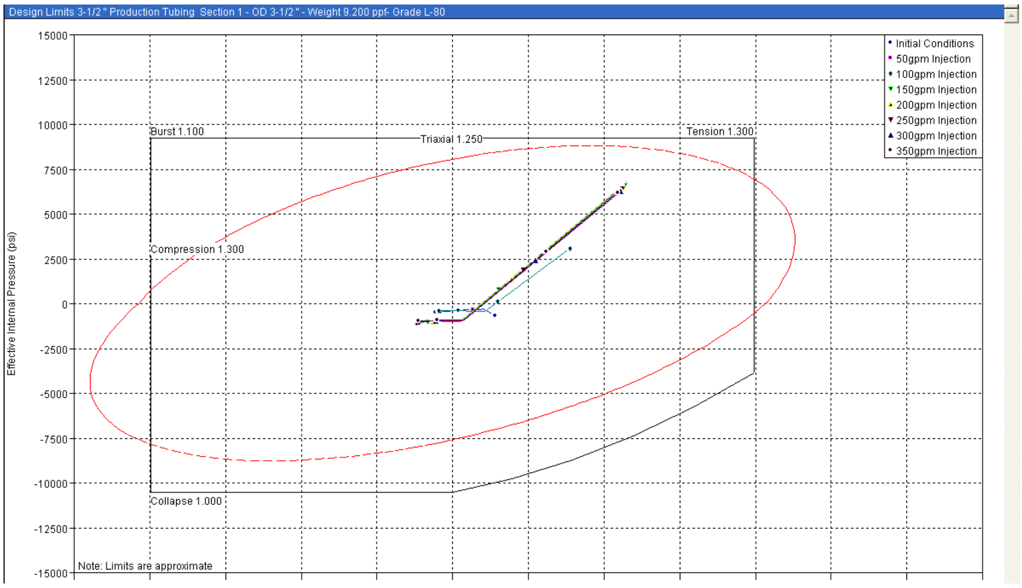
Red line indicates pressure above the Inverted SEPs whereas the blue line indicates pressure below the Inverted SEPs which is outside tubing environment.

Black line indicates the pressure differential across the packer (ΔP). Lesson learnt from the analysis of this variable of rate of injection based on constant pump pressure of 5000psi shows that ΔP decreases for every increment of the rate of injection.

Inverted SEPs will not be affected in term of ΔP for high rate injection intervention operation (i.e. Acid Fracturing, Diesel Bullheading)

4.8. Stress Analysis Simulation

4.8.1. Tubing Stress Analysis



Graph 6 - Design Limits Tubing Effects on High Rate Injection

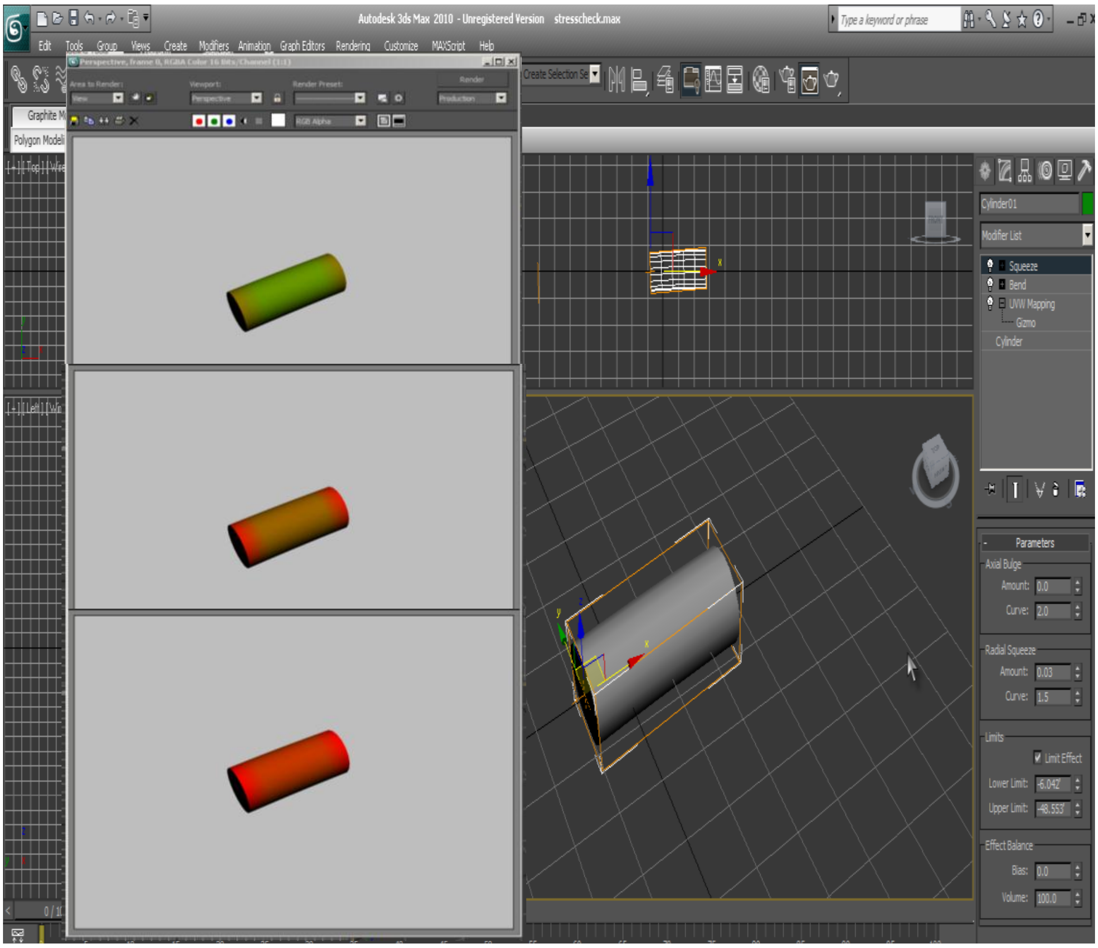


Figure 29 - Tubing Stress Analysis (3DsMax)

This simulation is carried out using WELLCAT and 3DsMax for Stress Squeeze Analysis on tubing shows that latching force of packer is distributed evenly across existing tubing stub. Based on high rate injection operation on design limits of the tubing stub, shows that higher injection rate resulted in prone elongation based on tension deprived factor.

4.8.2. Elastomer Stress Analysis

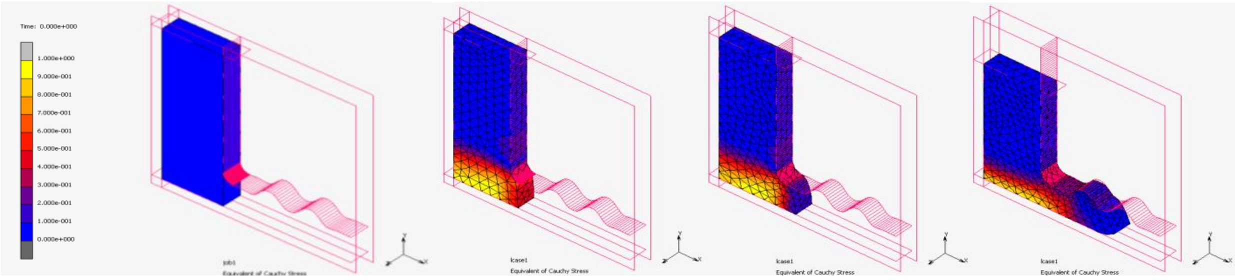


Figure 30 - SEPs Finite Element Analysis (FEA)

This simulation is carried out using MARC Mentat Software Student Edition. Software is requested from MSC Software Corporation, California. As finite element analysis cannot be carried out using WELLCAT Software, alternative software is used.

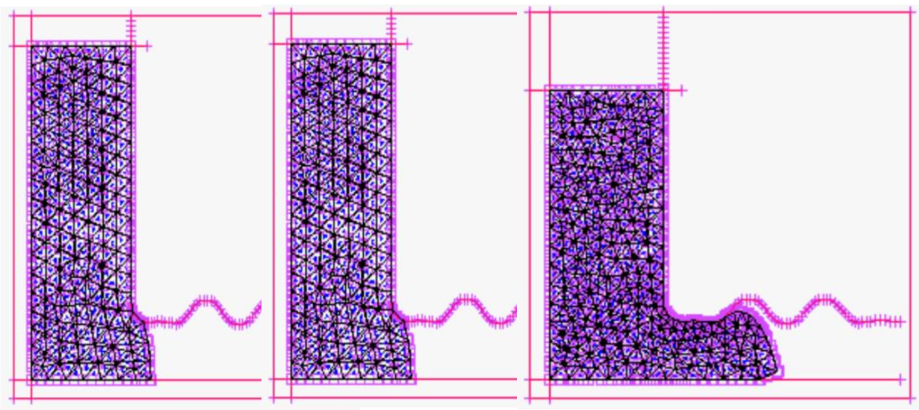


Figure 31 - SEPs Mesh FEA

Simulations on how swellable packer mesh affected by Cauchy stress set by using output data generated from WELLCAT Software. Text command and input (refer Appendix) is designed to analyse on the Mesh Effect between particle of elastomer element till failure. And result has shown (fig 30) shows that red colour mesh is the section where particles of the elastomer are stretched. Referring to the result (fig 30) the Inverted SEPs can expand up to 185% and by further experiment, it might expand more.

Figure 32 - Self Healing Properties of SEPs

Fig 32 shows that the element of this elastomer used in SEPs has the ability of self-healing and infinite long-term-sealing.

Regardless of the irregularity of the contact bodies, SEPs able to accommodate the crooked contact bodies.

Nonetheless, for micro-annulus development or tubing-crack failure, SEPs would be able to fill those holes via its expansion.

4.9. New Workover Method Simulation

Run Overshot Completion (New 8.12" Dual Overshot Non Cut-Lip c/w 87.74" Inverted SEPs Lite)

1. Retrieve wear bushing. RIH 3-1/2" dual completion with inverted swell packer overshot assembly. Land hanger and set production packer.
2. M/U and RIH with the 3-1/2" dual string completion with RDH packer as per the attached completion schematic and approved completion tally.
3. Run the dual production tubing and associated jewelry to the required depth to install TR-SCSSV. (Run slowly while watching surge pressures and volume losses) Hook up the control line and test to 5000 psi for 10 minutes. Bleed off control line to 3000 psi and continue RIH.
4. Install cross coupling control line clamps at all connections above TR-SCSSVs. Record the number of clamps installed.
5. Continue to RIH with the tubing strings until the No-go locator in the overshot casing sit on the top of LS tubing stub at 5853 ft MDTHF. Count tubing balance.
6. Record slack-off weight.

7. Repeat and record these loads twice. Recorded slack-off weight must decrease as the second mule shoe weight is hold by the LS tubing stub.
8. As the second mule shoe drop back to its normal position, the recorded slack-off weight will increase back to normal 7800ls. (Estimated slack-off weight for overshot casing to sit properly is 7800 lbs.)

Note: Highlighted part in yellow is additional SOP for the verifying 2nd mule shoe (inner) tubing-latch-on mechanism is completed and tubing stub is not stuck on the lip.

9. Verify with Workover Supt in town that the seal unit is on depth prior to installing the tubing hanger.

Note: Space out the dual tubing hanger so that the LS tubing stub fully swallow and located at overshot casing no go locator.

10. Space out and install tubing hanger as per Solar Alert Installation Procedure. Strip back encapsulation and hookup control line. Do not install protector 1.83 m (6 ft) below hanger - use duct tape to hold control lines in place. Pressure up control line to 5000 psi and test for 15 minutes. Bleed off to 3000 psi.
11. Rig up pump-in-tee assembly.
12. Drain BOP stack through annulus valve on B-Section. Ensure that the hole is kept full by lining up trip tank to auto gravity fill the annulus.
13. Land tubing hanger and lock tie-down bolts. Checks to ensure that control line pressure to the TR-SCSSVs have not been bled off.
14. R/U Slickline on SS. RIH with 2.8" drift and tag XN Nipple. Record the depth. POOH.
15. R/U Slickline on LS. RIH with 2.8" drift and tag PXN plug installed at XN Nipple. Record the depth. POOH.
16. 13. Rig up pump-in-tee assembly on LS and line up to Cement Unit and pressure test surface lines to TIW Valve on Pump-In-Tee to 300psi (5 mins) and 3000 psi (5mins) – Chart Test.
17. Once test is completed bleed off pressure to zero and open TIW Valve.
18. Pressure up slowly down the tubing with Cement Unit and ensure that the pressure test is charted. Continue to pressure up to 300 psi and hold for 5 minutes then to 2000 psi hold for 10 minutes to verify the integrity of the tubing.

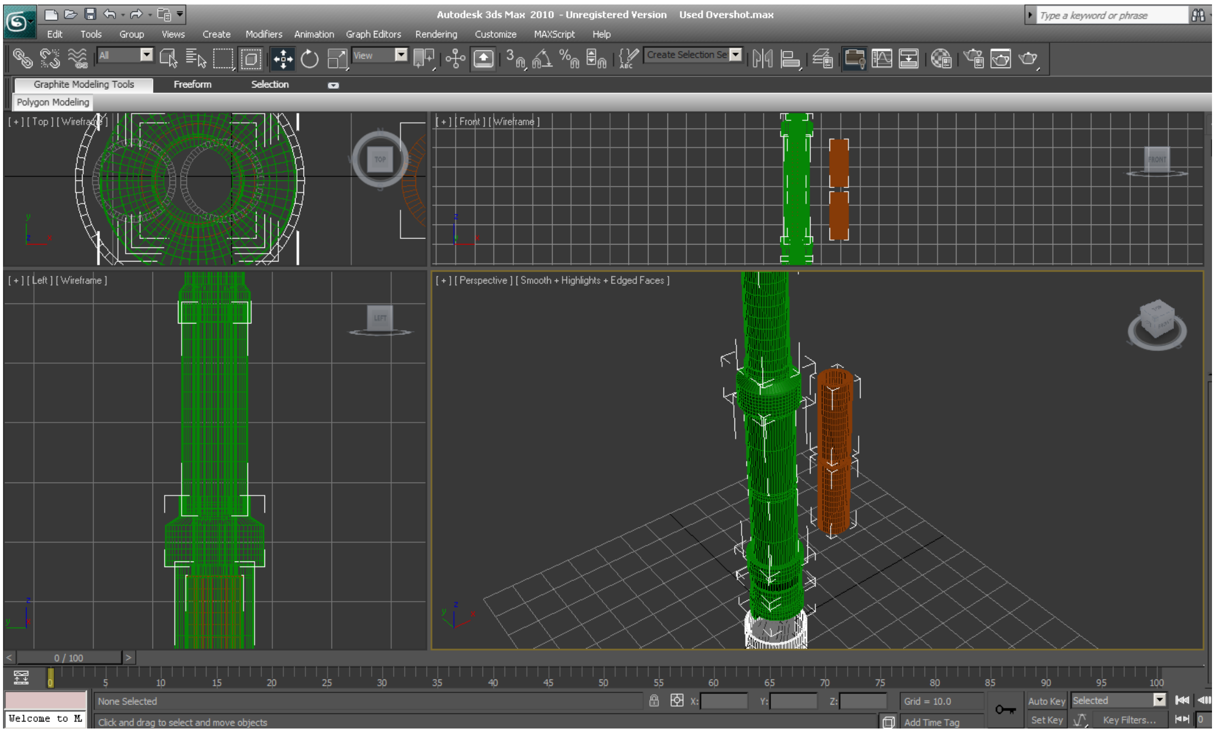


Figure 33 - New Workover Simulation (3DsMax)

19. Perform inflow test TRSV by bleeding off pressure to 100 psi. Test for 10 minutes. Bleed down to 0 psi and open the TIW valve.
20. Rig up pump-in-tee assembly on SS and line up to Cement Unit and pressure test surface lines to TIW Valve on Pump-In-Tee to 300psi (5 mins) and 3000 psi(5mins) – Chart Test.
21. Once test is completed bleed off pressure to zero. Break circulations by pumping in the SS until return is observed from the annulus and continue to pump 3 bbls to ensure ball seat is free of debris and there is no communication from tubing to annulus.
22. Drop 2” brass ball down the SS and allow it to gravitate to the POP.
23. Pressure up slowly down the tubing with Cement Unit and ensure that the pressure test is charted. Continue to pressure up to 300 psi and hold for 5 minutes then to 1000 psi hold for 10 minutes to verify the integrity of the tubing.
24. Pressure up SS to 2000psi and hold for 15 minutes to fully set the 9-5/8” BHD packer (BHD STS pressure is 1368 psi). Bleed down slowly to 1500 psi and lock pressure.

25. Line up cement line to LS and flush surface lines with at least 3 bbls. Pressure up the LS to 1500 psi and lock pressure.
26. Hook up cement line to the annulus valve on B Section. Test surface line to 3000 psi. Roll over cement unit pumps until pressure reaches 250 psi, monitor annulus for 2 minutes.
27. Continue to pressure up to 500 psi (5 minutes) and 1000 psi (10 minutes) to pressure test the 9-5/8" BHD Dual Hydraulic packer from above. Observe for pressure holding. Bleed off slowly the annulus pressure and LS pressure to 0 psi.
28. Pressure up SS to 3000 psi or until the POP is sheared off. The POP should shear off at 2950 psi. Bleed down to 0 psi.
29. R/U Slickline on LS. Set PX-Plug at X-nipple between BHD and overshot assembly. Open up SSD on top of BHD packer and circulate packer fluid. Close back SSD. Retrieve PX-Plug. R/D Slickline.

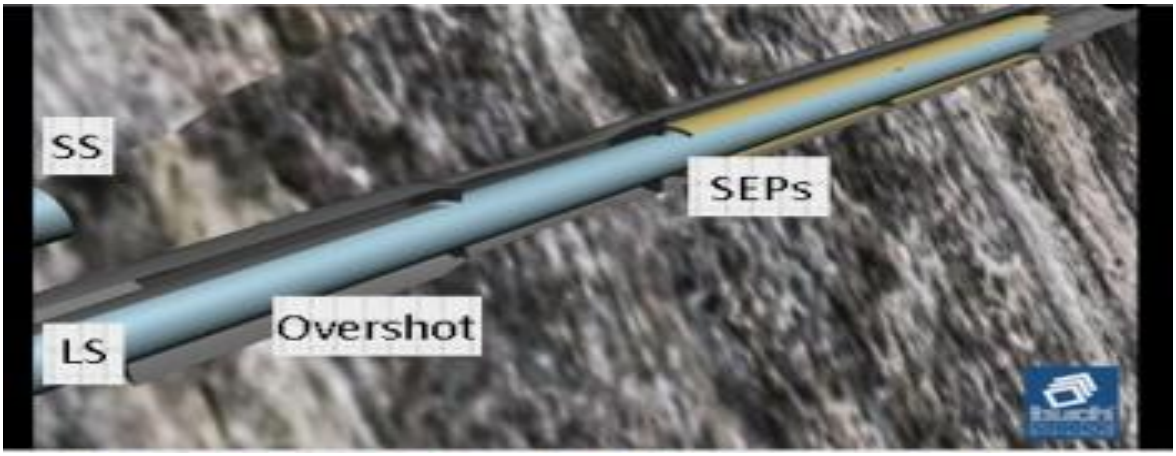


Figure 34 – Tubing Swallow Mechanism

4.10. Discussion

All factors and parameters for this project are discussed throughout the parameters tested:

- Overshot Design
- Test Fixture Design
- Cooking Summary
  - Cooking Charts
- Pressure Test Summary
  - Pressure Charts
- Pressure Test Simulation
  - 5000psi – 9000psi
- Maintenance Simulation
  - Initial Conditions
  - Production Shut-In
  - Full Tubing Evacuation
  - Tubing Leak
  - Overpull while Running
- High Rate Pumping Operation Simulation
  - 50gpm – 1000gpm Diesel Pumping
- Stress Analysis Simulation
  - Tubing Stress Analysis
  - Elastomer Stress Analysis
- New Workover Method Simulation

Based on the Overshot Design done in Baram Alpha Well – X, some alteration on the design needs to be change based on failure of the project. Alterations are included throughout this project research, where the mule shoe design is changed from Cut-Lip type to Non-Cut-Lip type (Flat Lip). And for challenging the previous design where the failure is listed as tubing stub stuck on the edge of the Overshot Lip, additional Flat-Lip mule shoe with vertical-motion swallow method is included.

Cooking summary of the SEPs is used as a factor to acquire the pressure maximum exerted by specific length of the Inverted SEPs. While for the Pressure Test Summary in lab and using SwellSim® Software, the data output gathered are as follows - differential pressure, time to swell, contact timing and etc. and those outputs are included as the design parameters of the Inverted SEPs

As for the project research, this project is prone to reverse engineering, where researches and simulations are constructed for better understanding and creating standard parameter design for further usage of this new methodology in workover. Temperature plays high control on this fixture design because elastomer could be affected by high temperature.

Pressure Test simulation ranging from 5000psi to 9000psi data input achieved good result, which it doesn't affect the temperature of the packer also the tools efficiency. Whereas for maintenance simulation, which in turns post-job review, resulting in standard-range rating for the BHA; post-job maintenance to the well installed with this Overshot Inverted SEPs tool will not affect the well and also the tool installed.

The most crucial part of this project is the theory of high rate pumping super-cooling effect to the tubing, which in turn might affect the SEPs as the SEPs is now directly come in contact with tubing environment. From 50gpm to 100gpm Diesel pumping simulation done to the tool assembly, this research gathered useful data such as, the tubing-to-packer force and latching force of the packer. Analysis of those data resulting in range of differential pressure for safety measure of high rate pumping operation of 1000gpm still at optimum, and further simulation testing is needed till destruction so max differential pressure of 10,000psi can be achieved.

Tubing Stress Analysis simulation shows how tubing react to force exerted by SEPs during expansion and also during high rate pumping operation. And the result shows that SEPs expand evenly distributive, with factor of constant swelling fluid contact, although some data output shows that at 1000gpm injection rate, the tubing appears nearly exceeding the safety rating. Whereas for elastomer stress analysis, based on differential pressure factor shows how the SEPs mesh movement. Finite element analysis still new in industry yet SEPs shows good mesh flow through crack or porous degraded-tubing (micro-annulus and tubing crack). Differential pressure need to be secured as from the FEA, the output shows that certain region experiencing high-stretching value, which might damage the particle bond in the Elastomer element.

For the new workover method simulation, new design of mule shoe guide (flat-lip) completed with the 2^{nd} mule shoe guide (flat-lip) would assist much in dual string completion top-half-completion workover. This new workover method simulation executed resulted in lowest possibility of getting the tubing stub stuck on the lip section of the overshot mule shoe guide. Additional SOP prior to the 2^{nd} mule shoe installation added more efficiency for better workover.

5. CONCLUSION AND RECOMMENDATION

From the result, I conclude that the Overshot Inverted SEPs solve TR-SCSSSV and SPM problem, which the conventional method results in much higher in marginal cost to be workover for just top-half completion or tubing ID restriction. For that purpose, Overshot Inverted SEPs are recommended. Same purpose delivered with lower marginal cost is a good economic analysis.

Correct standard operating procedure (SOP) and detailed design parameters of the SEPs are needed for every job executed. With those listed factors, they reduce the risk-to-fail possibility of the Overshot Inverted SEPs.

And new mule shoe guide design for the Overshot BHA will assist more on tubing-latch-on problem.

6. REFERENCES

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APPENDICES

Marc Mentat Log Report

Marc 2012.1.0 Student Edition , Build 149172 Windows_NT version

----

Program name : marc

JobID : C:\MSC.Software\Marc_Student_Edition\2012\mentat2012\BUCH_fyp\rubber_job\sims\rev_02\tet_rubber_job1

Version type : i4

User subroutine name :

User objects/libs :

Restart file job ID :

Substructure file ID :

Post file job ID :

Defaults file ID :

View factor file ID :

Save generated module: no

MPI library : intel-mpi

Auto restart : 0

Contact decoupling : 0

DDM processes : 0

Solver processes : 0

GPGPU option :

Host file :

Distributed i/o :

Run directory : C:\MSC.Software\Marc_Student_Edition\2012\mentat2012\BUCH_fyp\rubber_job\sims\rev_02

Scratch directory : C:\MSC.Software\Marc_Student_Edition\2012\mentat2012\BUCH_fyp\rubber_job\lib

Default bin directory: C:\MSC.Software\Marc_Student_Edition\2012\marc2012\bin\win32

Material database : C:\MSC.Software\Marc_Student_Edition\2012\marc2012\AF_flowmat\

Sat 11/24/2012

02:05 AM

Marc 2012.1.0 Student Edition tet_rubber_job1 begins execution

(c) COPYRIGHT 2012 MSC.Software Corporation, all rights reserved

VERSION: Marc 2012.1.0 Student Edition, Build 149172 build date: Mon Jun 18 06:58:42 2012

Date: Sat Nov 24 02:05:23 2012

Marc 2012.1.0 Student Edition execution begins

Acquired 1 license for Student Edition Marc

general memory initially set to = 25 MByte

maximum available memory set to = 2047 MByte

general memory increasing from 25 MByte to 53 MByte

MSC Customer Entitlement ID

N/A

wall time = 2.00

tet_rubber.mfd (MARC® Mentat Finite Element Analysis)

```
C:\Windows\system32\cmd.exe

Version : Marc Mentat 2012.1.0 (32bit) Student Edition
=beg=    1 (magic)
         1234
=end=
=beg=    2 (entities)
           88
=end=
=beg=    3 (description)

=end=
=beg=  102 (nodes)
           1 -9.000000000000e-01 -9.000000000000e-01  0.000000000000e+00
           0            0
           2 -9.000000000000e-01 -9.000000000000e-01  2.000000000000e-01
           0            0
           3 -3.000000000000e-01 -9.000000000000e-01  0.000000000000e+00
           0            0
           4 -3.000000000000e-01 -9.000000000000e-01  2.000000000000e-01
           0            0
           5 -3.000000000000e-01  9.000000000000e-01  0.000000000000e+00
           0            0
           6 -3.000000000000e-01  9.000000000000e-01  2.000000000000e-01
           0            0
           7 -9.000000000000e-01  9.000000000000e-01  0.000000000000e+00
           0            0
           8 -9.000000000000e-01  9.000000000000e-01  2.000000000000e-01
           0            0
=end=
=beg=  205 (elements)
           1            8            7            8
           1            3            5            7
           2            4            6            8
           1            0            1            0
           0            0            0            0
=end=
=beg= 2509 (adapgs)
          73            6          184          185          186          187
  1.000000000000e+00  2.250000000000e+01  1.200000000000e+00  5.000000000000e+00
  2.000000000000e+01  2.000000000000e+01  2.000000000000e+01  5.000000000000e-01
  4.000000000000e-01  1.000000000000e+01  5.000000000000e+00  4.000000000000e+01
  4.000000000000e+01  4.000000000000e+01  4.000000000000e+01  9.000000000000e-01
  1.100000000000e+01  6.000000000000e+00  1.000000000000e+01  2.000000000000e+00
  7.000000000000e+00  1.570000000000e+02  1.000000000000e+00  1.000000000000e+00
  1.000000000000e+00  1.000000000000e+00  1.000000000000e+00  1.000000000000e+00
  1.000000000000e+00  1.000000000000e+00  1.000000000000e+00  1.000000000000e+00
  2.000000000000e+00  3.600000000000e+01  8.000000000000e-01  1.000000000000e+00
  1.800000000000e+01  3.600000000000e+01  1.000000000000e-03  1.800000000000e+02
  6.000000000000e+01  4.000000000000e-01  6.000000000000e+01  1.000000000000e+02
  1.500000000000e+00  1.200000000000e+02  1.000000000000e+00  5.000000000000e+01
  1.000000000000e+01  1.000000000000e-01  1.200000000000e+02  1.000000000000e+01
  1.000000000000e+00  1.000000000000e+00  1.000000000000e+00  1.000000000000e+00
  1.000000000000e+00  1.000000000000e+00  1.000000000000e+00  1.000000000000e+00
  1.000000000000e+00  1.000000000000e+00  1.380000000000e+02  7.500000000000e+01
adapg1
           1           13
           3
           1            0            0
           6
           3           22           23           40
          43           56
           1            1            1            1
           1            1
           3
           8          164          170
  5.000000000000e-03  1.000000000000e-01  3.000000000000e-02
           1

           0
=end=
```

tet_rubber_job1.out

(MARC® Mentat Finite Element Analysis of Swelling Elastomer)

C:\Windows\system32\cmd.exe

```
no friction selected
      no increment splitting during analysis
      separation based upon nodal forces:
       separation threshold is treated as a force
      suppress contact surface print out
      distance below which a node is
      considered touching a surface    =  default
      separation threshold             =  default
      contact bias factor              =  9.50000E-01
      $....contact body 1: rubber
      body number                 =    1
      body name                   = rubber
      number of sets of data         =    0
           body positioning data
      1st coordinate of center of rotation      0.00000E+00
      2nd coordinate of center of rotation       0.00000E+00
      3rd coordinate of center of rotation      0.00000E+00
      initial angle rotated around axis         0.00000E+00
program sizing and options requested as follows

          element type requested**************************        7
          element type requested**************************      157
          number of elements in mesh**********************        1
          number of nodes in mesh*************************         8
          large displacement analysis flagged************
          load correction flagged or set*****************
          values stored at all integration points********
          tape no.for input of coordinates + connectivity        5
          boundary conditions applied on current geometry
          no.of different materials    1 max.no of slopes        5
          number of points on shell section *************        11
          geometry updated after each load step**********
          new style input format will be used************
          mesh rezoning option is switched on************
          triangular interpolation is used***************
          number of processors used **********************        1
          multiplicative plasticity - radial return method
          three field variational principal used  *******
          elasticity uses updated Lagrange formulation **
          three field variational principal used  *******
          extended precision input is used **************
          Marc input version *****************************        11
          suppress echo of list items *******************
          suppress echo of bc summary *******************
          suppress echo of nurbs data *******************
          end of parameters and sizing
         ***************************************************
key to stress, strain and displacement output
                    element type        7
               8-node isoparametric brick

               stresses and strains in global directions
                1=xx
                2=yy
                3=zz
                4=xy
                5=yz
                6=xz
               displacements in global directions
                1=u global x direction
                2=v global y direction
                3=w global z direction
                    element type      157
               4+1 node tetrahedron (herrmann formulation)
               stresses and strains in global directions
                1=xx
                2=yy
                3=zz
                4=xy
                5=yz
                6=xz
                7=pressure

               displacements in global directions
                1=u global x direction
                2=v global y direction
                3=w global z direction
```