COMPARATIVE STUDY OF OPEN HOLE PACKERS

A thesis submitted in partial fulfilment of the requirements for the Degree of

Bachelor of Technology

(Applied Petroleum Engineering)

By

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CERTIFICATE

This is to certify that the work contained in this thesis titled "**Comparative Study Of Open Hole Packers**".

" has been carried out by Ankit Kukreti and Ankita Sharma under my supervision and has not been submitted elsewhere for a degree.

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ABSTRACT

Drilling of horizontal well continues to increase world wide. A significant number of these wells are completed either with screens or slotted pipe across the production intervals. Many of these completion require some form of annular isolation to separate different geological zones and to isolate the upper well bore. The new integrated system allows the production liner to be run into the well bore and a liner top hanger system set, multiple external casing packers selectively inflated at target locations to provide zonal isolation and then the radial section of the production liner cemented to provide isolation between the liner and the upper casing string. Well bore isolation is very important in order to properly produce the desired reservoir and without it unwanted gas would be produced choking of production of the desired hydrocarbon. The two main areas of well bore isolation are the horizontal lateral itself and build section. New alternatives can provide a well bore isolation for a long term in gage hole wells that were previously completed without zonal isolation. These technologies include the swelling elastomers and the reactive polymers which find application where barriers are sufficient to prevent migration of fines. For applications where hole geometry is unknown, sand control is necessary, gas is present or an immediate seal is required, an inflatable packer with a core that reacts with wellbore inflation fluid can provide an immediate, long seal for the life of the well without the need for cement inflation. To overcome the draw backs of the conventional cementing job, the external casing packers (ECP's) were introduced to avoid the need of cementing.

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CONTENTS

Zonal Isolation

The isolation of zones is necessary because the communication can lead to various problems like productivity loss, injection of fluids into the unintended zones, improper stimulation, loss of fluid along the annulus, production of sand, gas mitigation and finally the expensive remedial operations. When fluid flow in the annulus of an open hole, completion is left uncontrolled, the productivity of the well is jeopardized, and operator risk is elevated. Uncontrolled inflow in the annulus of horizontal wells leads to premature water coning, gas breakthrough and hot spots. Due to which there is a reduction in the production from the well, well life, profitability and the recoverable reserves, therefore the original purpose of the well gets defeated.

Historically, controlling inflow and fluid flow in the annulus was achieved the "hard way" by cementing across the production interval and then perforating. Cementing and perforating has proven to be complex, time consuming, and very costly. Cement or flush fluids may cause near wellbore permeability impairment. Additionally, a poor cement job can leave voids through which fluids can flow uncontrolled in the annulus. In many wells, the logistics, cost and limitations of cementing and perforating have led operators to use barefoot completions (i.e. completions without zonal isolation) that cannot mitigate water or gas along the wellbore. The water and/or gas influx decreases the well's ultimate ability to produce hydrocarbons. The new zonal isolation technology ranges from simple, self energized elements that do not require elaborate equipment or special personnel, to more complex, cement inflated elements. These products enable the operator to achieve uniform inflow along the entire horizontal wellbore, control treatments, and reduce water and gas coning to elevate production and increase profitability. These products can also be used for shoe integrity, gas cap isolation, lost circulation, scab liners across fractures and to plug back the wellbore.

Cementing in oil & Gas wells

In the construction of any oil well, primary cementing is a critically important operation. In the process of cementing, a sequence of fluids (e.g, wash, spacer, cement slurry) is pumped down inside the casing, which returns upwards through the annulus, thus cementing the steel casing into the borehole. Cementing is basically done to prevent any uncontrolled flow of formation fluids behind the casing by providing a continuous and impermeable hydraulic seal in the annulus as uncontrolled flow can lead to many serious problems.

A cemented casing would:

- Prevent fresh water well zones contamination.
- Prevent the caving-in of the unstable upper formation and sticking of the drill string.
- Provides a strong upper foundation so that high-density drilling fluid can be used to drill deeper.

- Isolates zones having different pressures or fluids (known as zonal isolation) in the drilled formations from one another.
- Seals off high pressure zones from the surface thus avoiding potential for a blowout.
- Prevents contamination of production zones.
- Provides a smooth internal bore to install production equipment.

Finally, even when surface casing vent flows are contained within the annulus, the fact of having pressure at surface prevents a well from being permanently abandoned, (i.e., safely), at the end of its lifetime. Instead, these wells become permanently shut-in and remain an environmental risk. From the financial perspective, hydraulic connection between different fluid-bearing zones tends to equilibrate pressures. If the zone that is initially at high pressure is an oil or gas-bearing zone, then the reservoir pressure will decrease as it equilibrates. In this case, significant losses in well productivity are common, and it is the consequent loss of revenue that provides a major motivation to oil companies for ensuring that primary cementing is effectively executed.

Primary objectives of a cement job

To provide a permanent fluid seal

For the entire life of the well, the flow in the annulus must be prevented. To achieve this, a cement job should be performed such that it completely displaces the mud in the hole. It should also remove the mud cake from the face of the open hole deposited by the drilling fluid.

To support weak or unconsolidated formations

The cement job exerts a radial force against the borehole wall which transmits a force that increases grain-to-grain loading in weak sand resulting in the compaction of sand and therefore increasing the sand strength.

To support casing string stress loadings

The cement job stabilizes formation movement and minimizes the stress loading of the casing in either collapse or buckling modes.

Problems associated in Cementing horizontal wells

In horizontal well completions, the effective cementing of the voids along the horizontal section is very difficult. However, in vertical wells, effective cementing of the tubing to the wellbore is routinely accomplished. Whereas, in horizontal as well as severely inclined wellbores, i.e. with an angle of deviation greater than about 45°, cementing is much more difficult. Therefore, the efficiency of zone isolation diminishes considerably. Also, due to the density of cement, sufficient mud and other residues are not completely displaced from the tubing/wellbore annulus, thus resulting in the channeling of cement and improper tubing or pipe/formation bonding. Also as the casing string itself tend to lay on the lower side of the wellbore thereby decentralizing the casing so that cement cannot uniformly be displaced completely around the casing itself. One of the more important drawback of cementing is that, cement potentially impairs near-wellbore permeability (increase in skin), and a poor cement job allows uncontrolled flow in the annulus, which, in a long, horizontal well, can lead to hot spots, water coning or gas breakthrough.

New alternatives

New alternatives can provide a well bore isolation for a long term in gage hole wells that were previously completed without zonal isolation. These technologies include the swelling elastomers and the reactive polymers which find application where barriers are sufficient to prevent migration of fines. For applications where hole geometry is unknown, sand control is necessary, gas is present or an immediate seal is required, an inflatable packer with a core that reacts with wellbore inflation fluid can provide an immediate, long seal for the life of the well without the need for cement inflation.

To overcome the draw backs of the conventional cementing job, the external casing packers (ECP's) were introduced to avoid the need of cementing.

The external casing packers provide as good seal as cement between the casing and the annulus and that too at lower risk and lower costs. The ECP's and the cement performs the same job.
There are various types of external casing packer
1) ECP (cement inflated).
2) RC (reactive core) packer.
3) MPAS (Extruding packer.
4) RE (reactive element) packer.
All the ECPs are used for sealing the annular space as well as for the isolation of oil, gas and water zone

Applications of Open Hole Packers

- Block gas migration
- Provide zone separation
- Support stage cement job
- Block water flow
- Isolate loss circulation zone

- Protect sensitive zone
- Plug and abandon

Fig. 4.1 Isolation of Oil/Water Contact

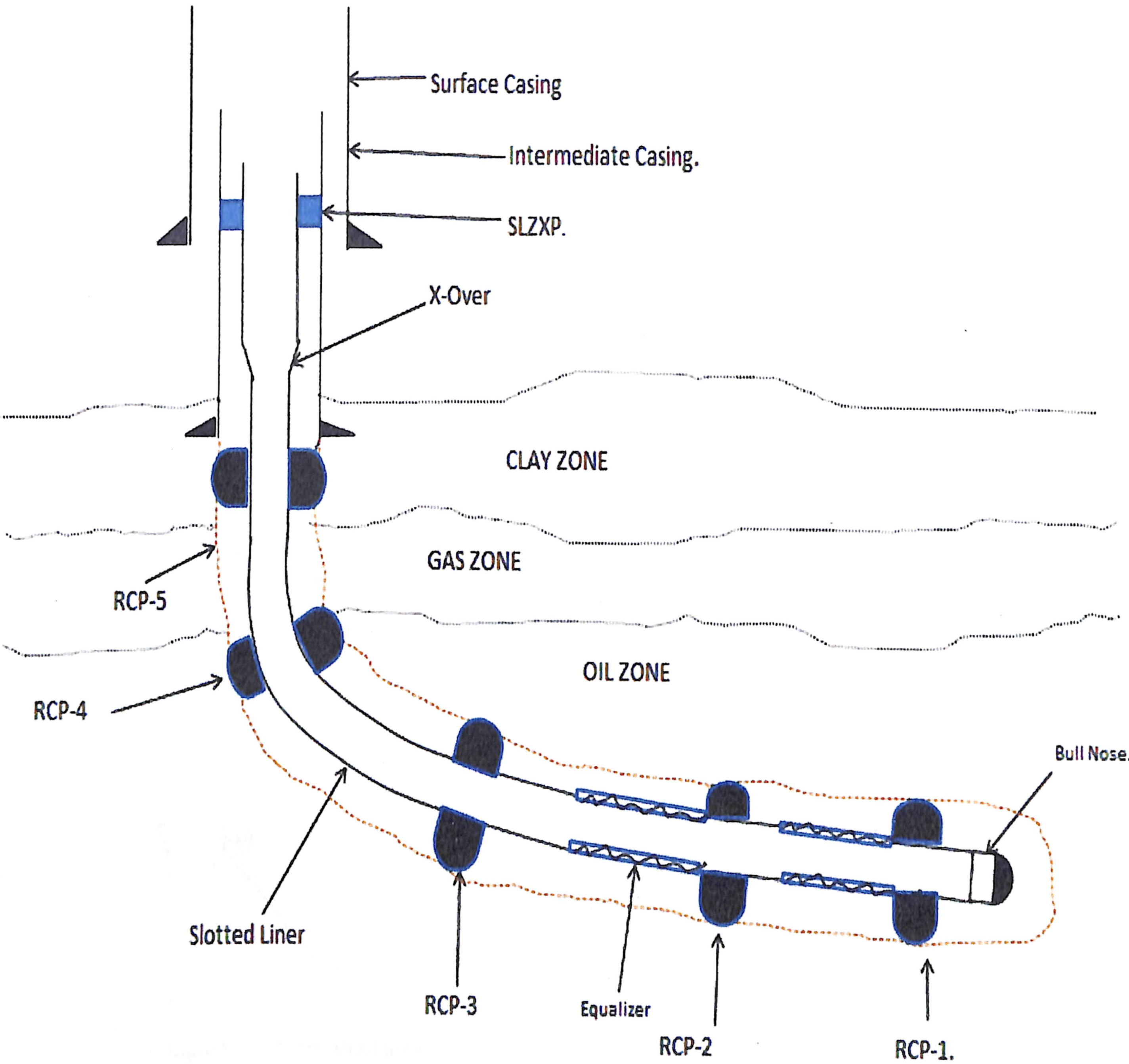


Fig. 4.2 Isolation of Gas Zone

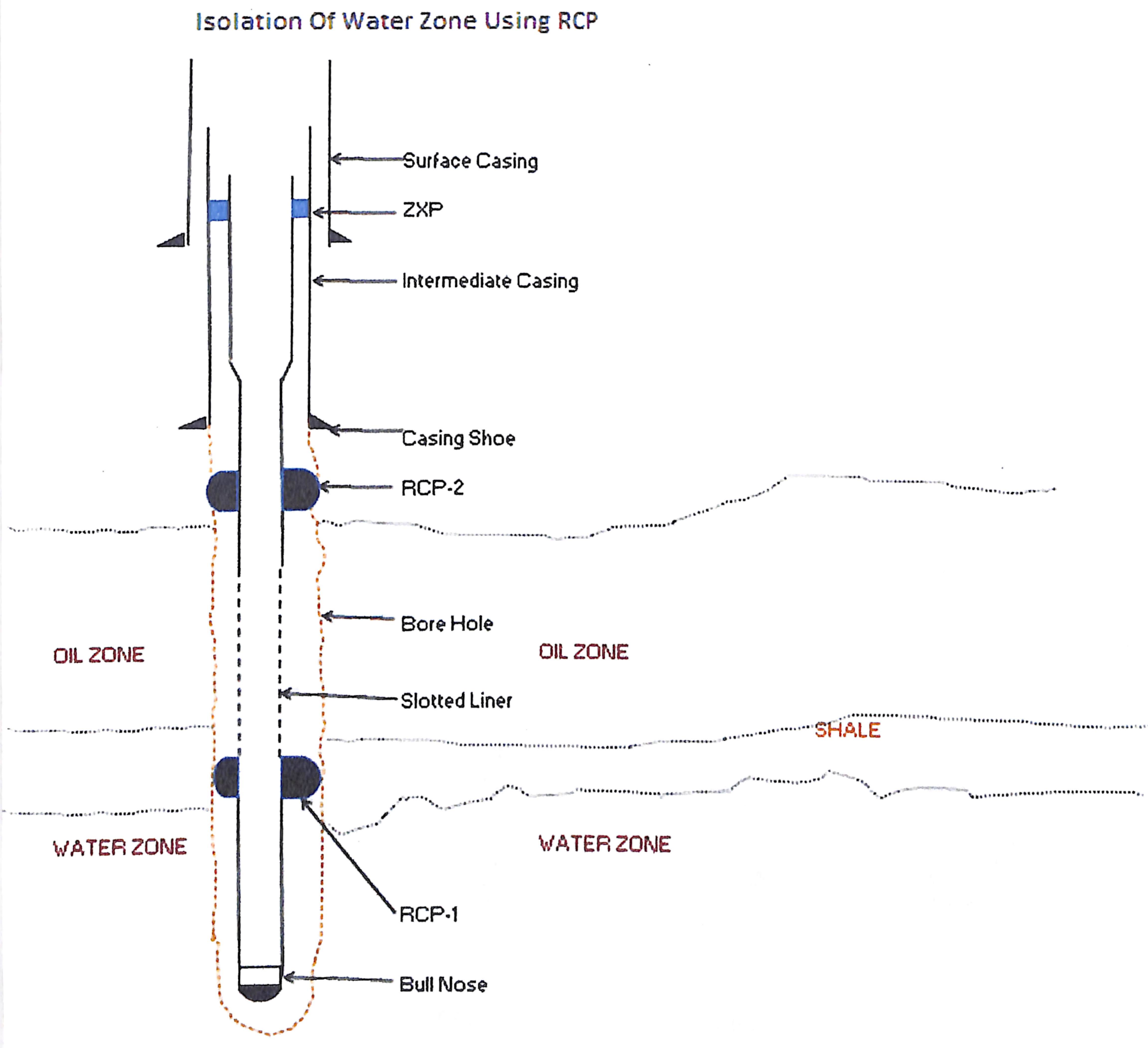


Fig. 4.3 Isolation of Water Zone

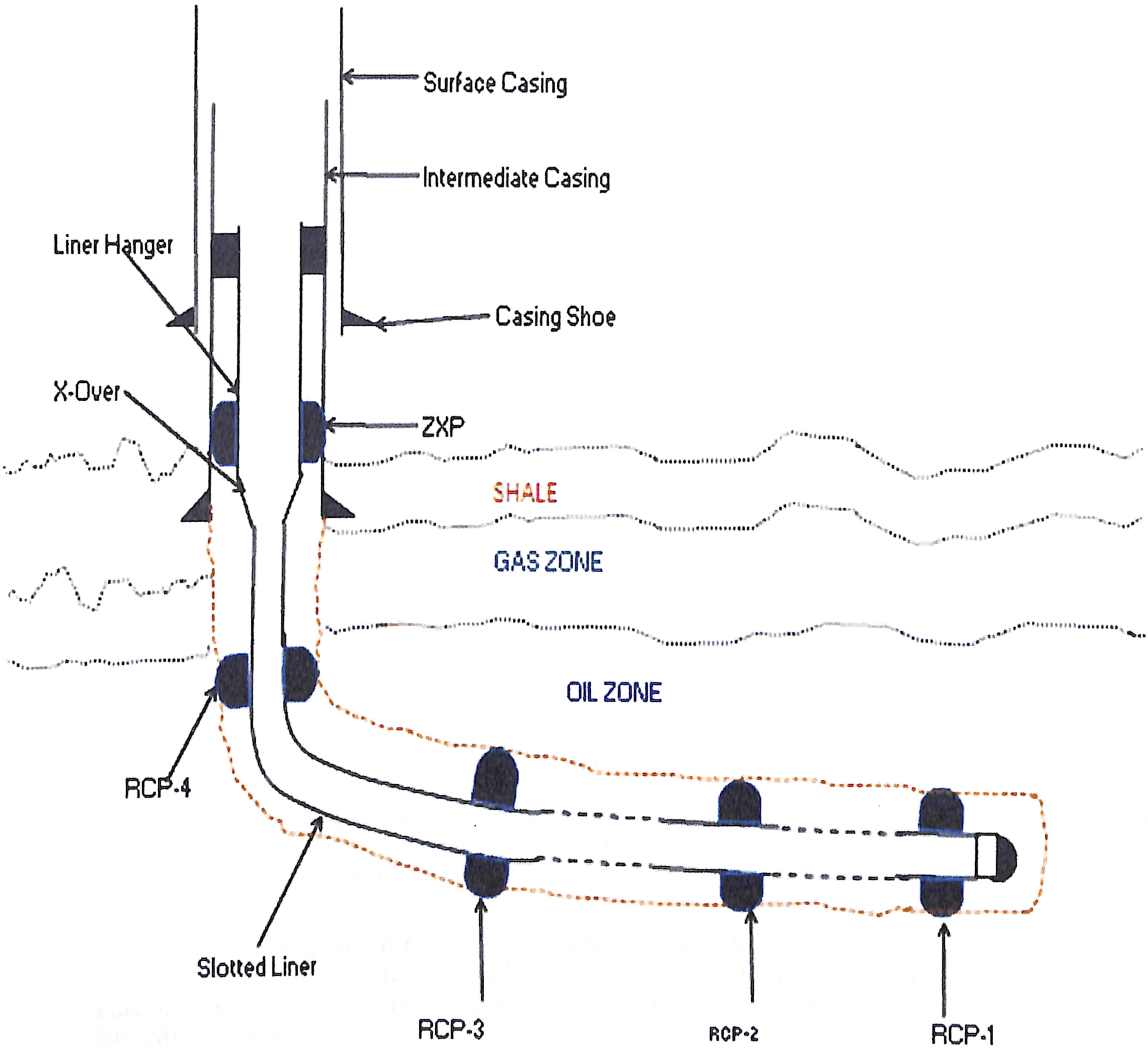


Fig.4.4 Segmented Production

Introduction to ECP

The cement inflated External Casing Packer (ECP) is a type of open hole packer with an Inflatable Packing Element that is run as an integral part of the casing string. It provides a seal between the casing OD and the well bore. The Inflatable Element of the packer is expanded by pumping the fluid down the casing and is compatible to ongoing cementing operations. The open bore external-casing packers directly isolate and separate formations and also ensures optimized conditions for cement girt building and setting in adjacent zones. In particular the packers of this series serve to protect cement slurry at the hardening stage against formation gas and aggressive fluids, and to center the adjacent portions of the casing. They also contribute to the building of cement slurry sedimentation zone above them, protect cement plugs against shock waves generated during perforation jobs and help to keep the cement plugs stuck to the casing under variations in axial loads applied to the casing. Besides that due to complete separation of fluids in the annulus, the packers serve to reduce pressure and to eliminate any significant water production from the cement slurry below the packers. It means that the cement plug in this zone will not shrink and will stick to the casing properly. Thus a packer set above the producing formation will help to retain its reservoir properties during WOC stage.

How does ECP help to solve cementing problems?

Prevent Loss of Cement

External Casing Packers can be positioned in the casing string directly above a lost circulation zone. The packer effectively prevents the loss of high-density cement slurries into the lost circulation zone. For these applications, a second stage cementing operation is normally performed above the ECP, after setting the packer.

Helps in Centering Casing in Horizontal Wells

Several External Casing Packers can be used on horizontal casing strings in order to centralize casing and to ensure even distribution of cement around the casing.

Prevent Gas Migration through Cement Columns

In many wells; gas migration through cement slurry can be prevented by setting an External Casing Packer directly above a high pressure gas zone. Improved cement integrity will be achieved.

Prevent Unwanted Water Production

An External Casing Packer can be positioned slightly above an oil-water or a gas-water contact, in order to minimize water production from those zones.

Minimize Damage to Sensitive Formations and Barefoot Completions

In the past, barefoot completions were used to minimize formation damage to production zones. However, today's technology, using under-balanced drilling methods, allows drilling of the well to the required total depth, and to set External Casing Packers directly above sensitive formations.

Types of ECP

1. **RTD External Casing Packer:**
   (Rib Type, Top Draw type) - The RTD-II ECP has an inflatable element with continuous rib type reinforcing. The ribs are stainless steel straps that overlap each other and form a steel shell when the element is expanded. The OD of the tool is 1-1/8" to 2-3/8" larger than the OD of the casing on which it is run.

2. **RTDX External Casing Packer:**
   (Rib type, top draws extra clearance OD) - The RTDX-II ECP is the same as the RTD-II except that the OD is reduced and is 1" to 1-1/4" larger than the casing in which it is to be run. This allows greater clearance when running in tight holes.

Both the RTD and RTDX use a single set of the four valve system.

3. **Pay Zone External Casing Packer:**
   Pay Zone External Casing Packers are 20 & 40 feet long and have two set of redundant four valve system.

4. **Iso Zone External Casing Packer:**
   Iso Zone External Casing Packers are 7 &10 feet in length with only one set of redundant four valve system, also Iso zone ECP has shorter steel ribs at the packer.

5. **Extreme Zone External casing Packer**:
   This type of an ECP is used in extreme conditions and has the highest pressure rating of all the ECP's; it is also 20 & 40 feet long but has an added advantage of an inflatable element with non continuous rib-type reinforcing at each end of the element. The ribs overlap each other with a composite reinforcement that forms a steel shell at each end of the element when it is expanded. The end assemblies are specially designed to provide enhanced performance in oval, out of round, and washed out wellbores.

Standard Four Valve System

The Standard Four Valve System comprises of the Shear Valve (SV), the Check Valve, the Lee Check Valve, and the Inflation Control Valve (ICV). The Four Valve System was specially designed for applications where the inflation fluid may be highly erosive, such as cement or heavy drilling muds.

Shear Valve (SV)

The Shear Valve along with the Break off Rods prevents premature inflation of the Inflatable Element. This valve is shear pinned to a closed position such that a predetermined differential pressure between the casing and the annulus is required to open the inflate path to the Inflatable Element. Once the element is inflated and the casing pressure is bled off, the valve returns to its original closed position and seals pressure in the Inflatable Element. The non locking Shear Valve does not lock closed, and can be reopened with the application of additional casing pressure.

Lee Check Valve

The Lee Check Valve seals pressure in the Inflatable Element. It allows the valve system to remain pressure balanced while running in the wellbore. It is spring loaded to the closed position. It opens with annular pressure to allow passage of annular pressure to balance the o-rings of the shear valve thus relieving the atmospheric pressure trap between the Shear Valve and the Check Valve.

Check Valve

The Check Valve seals pressure in the Inflatable Element. The Check Valve is spring loaded to the closed position and opens with casing pressure to allow passage of inflation fluid from the casing into the element. It then closes to trap pressure inside the element.

Inflation Control Valve (ICV)

The Inflation Control Valve is a normally opened valve which closes at predetermined pressure values of the inflation pressure. Thus it limits the inflation pressure of the Inflatable Element by blocking the inflation passages when the inflation pressure in the Element reaches a predetermined value thereby protecting the element from over inflation due to the high hydrostatic pressure that may be present inside the casing at the time of inflation.

Working of the valve system:

When the closing dogs sets in to the closing dog profile then the sub set down weight of about 10 klbs is applied to complete open the CCV and another 500 psi pressure is applied to keep the CCV open. As per the rating of the shear wire used in the shear valve, pressure is applied from the surface, normally shear wire rating of 1000 or 2000 psi is used as per the choice of the operator. Pressure is increased in an interval of 200 psi and is recorded on a pressure Vs time graph, at the shear pressure of the shear wire the wire in the shear valve breaks and the fluid (cement) enters in to the ECP. The Check valve is a spring loaded valve which opens as the pressure (of the advancing cement slurry) acts on the check valve. The Lee check valve enables to maintain hydrostatic pressure balance within and outside the valve collar by removing the entrapped air in between the check valve and shear valve which otherwise could lead to the collapse of the valve assembly. Both the check valve and Lee check valve are spring loaded valves. Cement slurry inflates the ECP from bottom to top, as the cement inflates the ECP pressure inside the ECP inflatable element starts to stabilize and exerts pressure on the Inflation Control Valve (ICV) which closes as the requisite pressure to break the shear wire of the ICV is achieved leading to no more cement entry in to the inflatable element .The pressure is then bled off to close the shear valve and check valve to seal of the pressure inside the ECP.

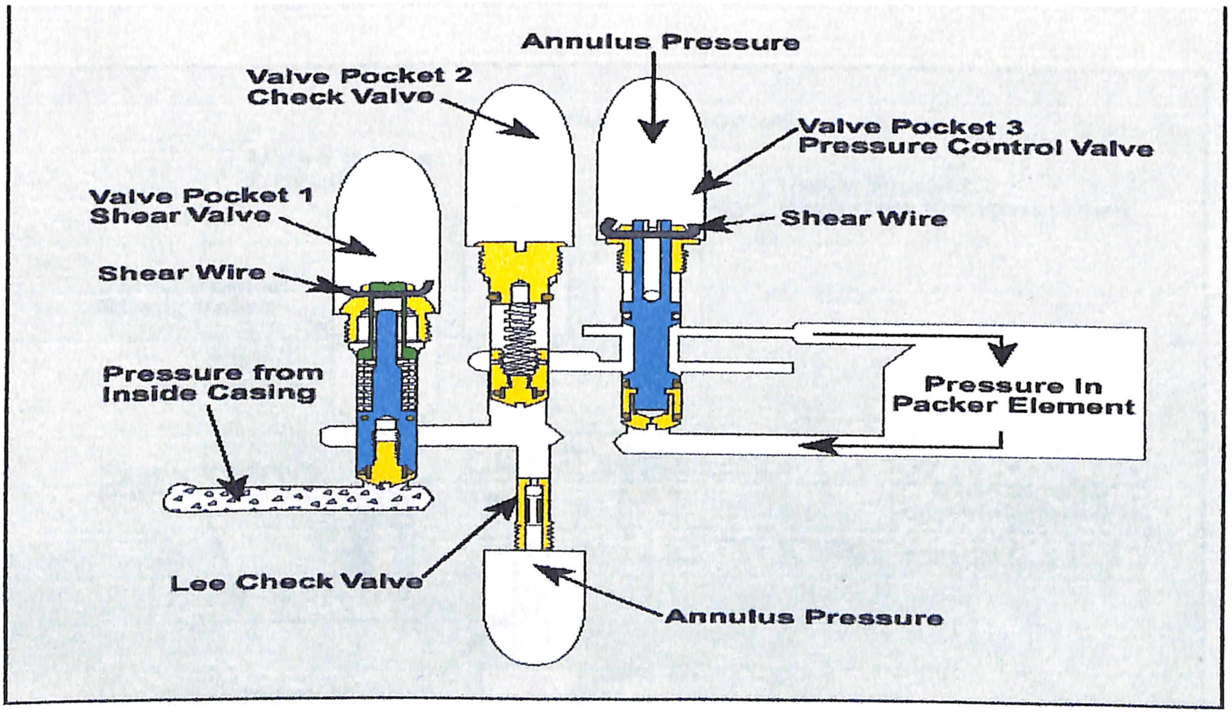


Fig. 5.1 ECP Valves in closed position

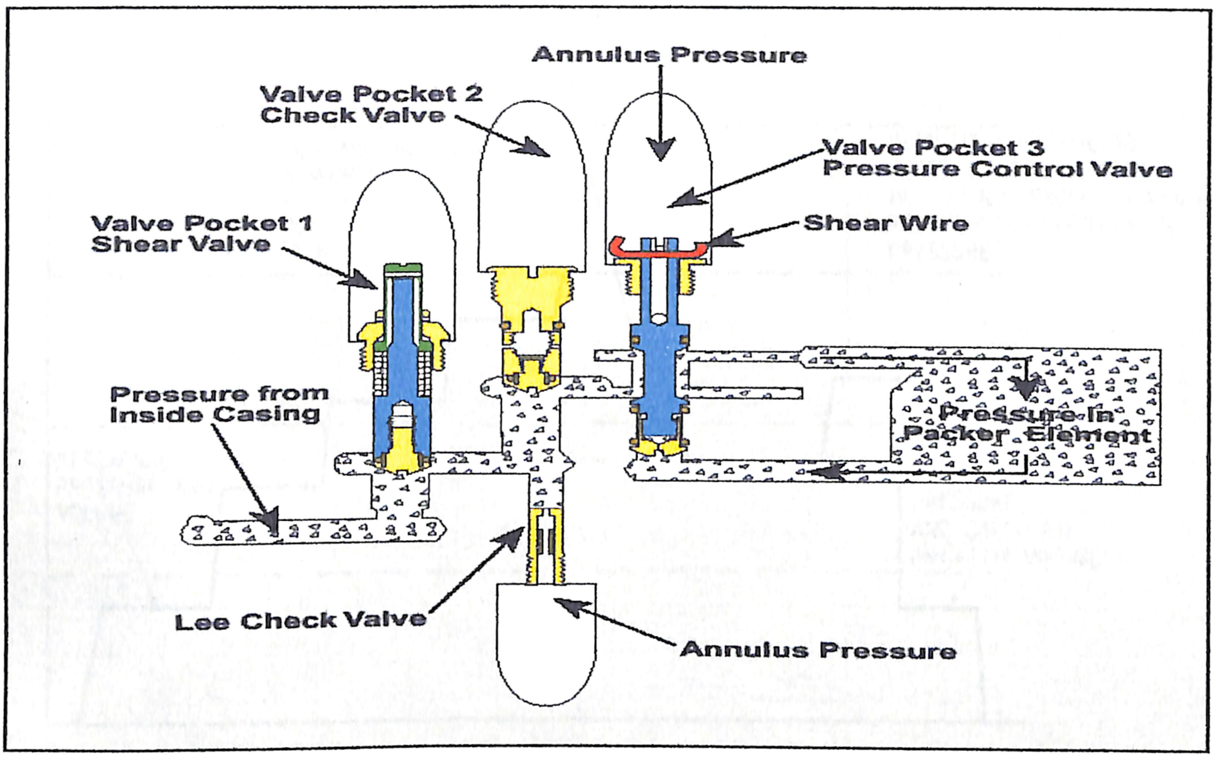


Fig. 5.2 ECP Valves in run in position

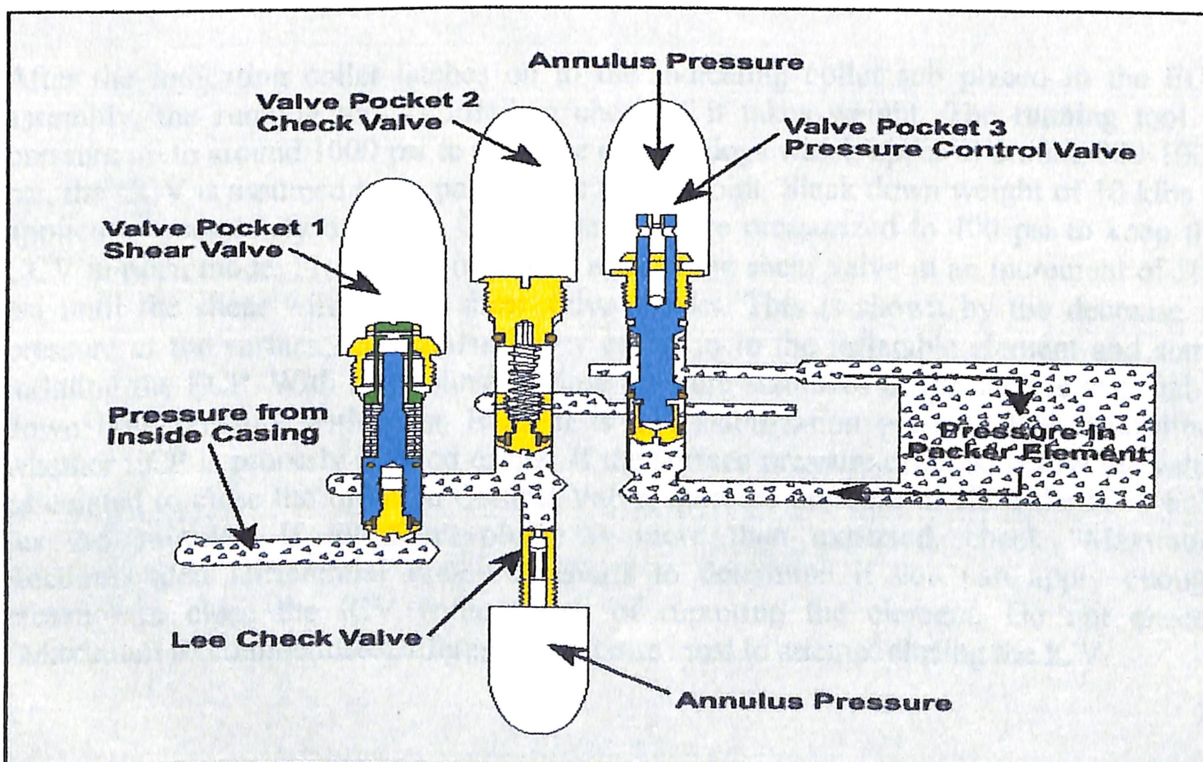


Fig. 5.3 ECP Valves in inflate position

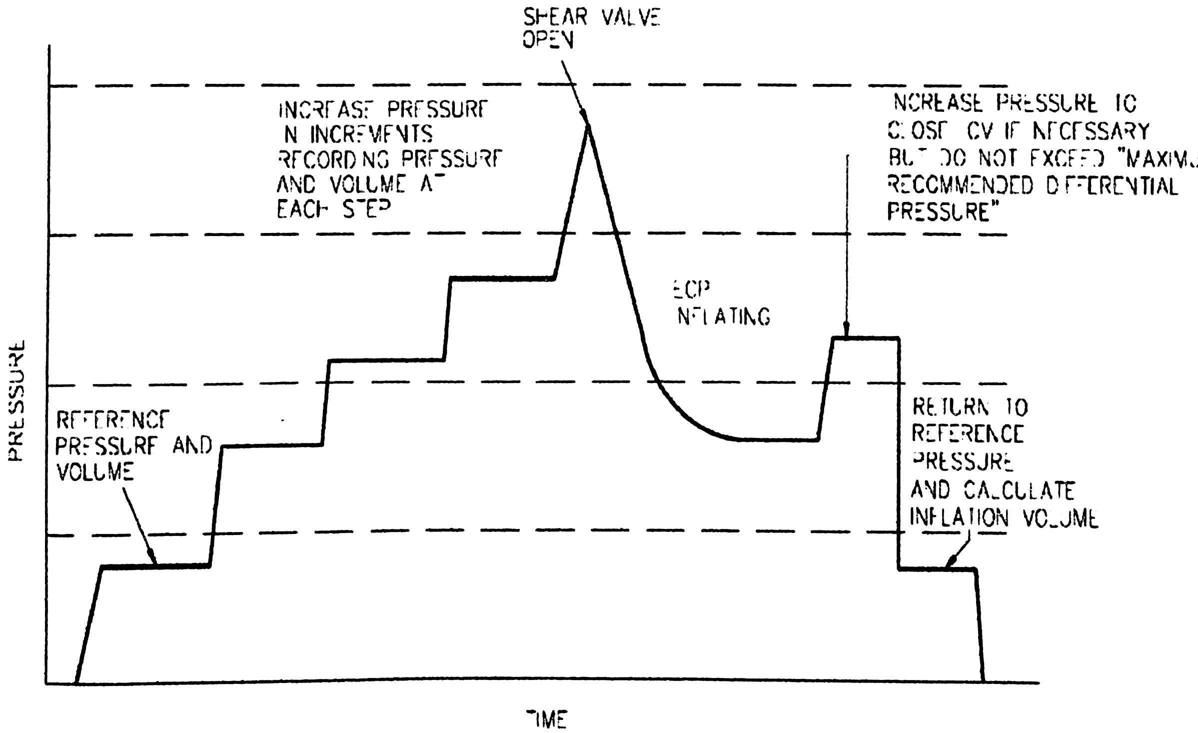


Fig. 5.4 Pressure Vs Time curve

After the indicating collet latches on to the indicating collet sub placed in the ECP assembly, the running tool is lifted to check if it takes weight. The running tool is pressure up to around 1000 psi to open the closing dogs which opens at around 900-1000 psi, the CCV is assumed to be partly open at this point. Slack down weight of 10 klbs is applied to completely open the CCV. The dogs are pressurized to 400 psi to keep the CCV in open mode. Pressure is increased against the shear valve in an increment of 200 psi until the shear wire of the shear valve breaks. This is shown by the decrease in pressure at the surface; the cement slurry enters in to the inflatable element and starts inflating the ECP. With due course of time pressure stabilizes at the surface at a stable down hole pressure within the ECP. It is this stabilization pressure that determines whether ECP is properly inflated or not. If the surface pressure dropped below the value calculated to close the Inflation Control Valve, increase pressure to close the ICV, hold for 2-5 minutes. If inflation volume is more than expected, check "Maximum Recommended Differential Pressure" charts to determine if you can apply enough pressure to close the ICV without risk of rupturing the element. Do not exceed "Maximum Recommended Differential Pressure" just to attempt closing the ICV.

The selective inflation setting tool assembly for the ECP

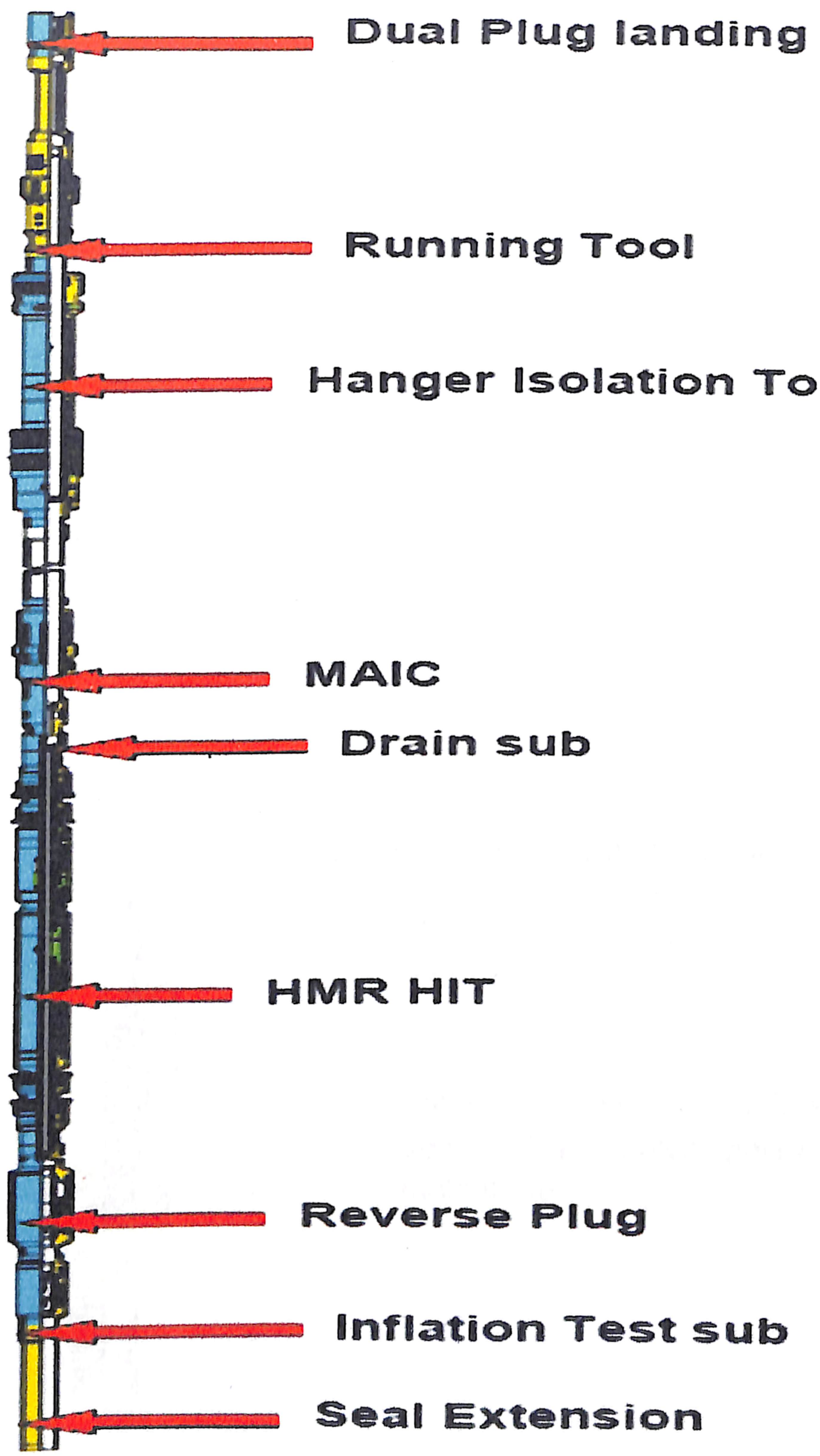


Fig.5.5 Inflation setting tool assembly for the ECP

Dual plug landing sub

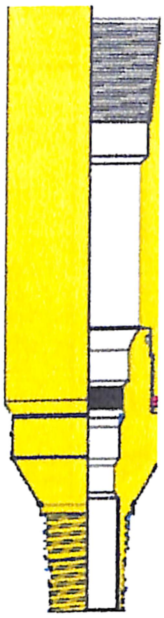


Fig. 5.6

Landing sub in running position

- Placed between drill pipe and work string for HMR HIT assembly.
- Accepts combination wiper plug / pump down plug.
- Locking mechanism prevents wiper plug from moving up the drill pipe.

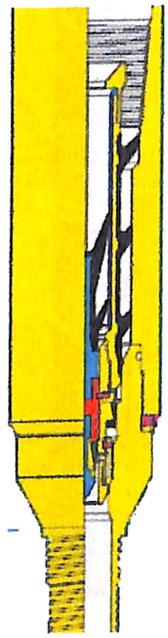


Fig. 5.7

Landing sub in landed position

- Nose shear releases putting the pump down plug in the released position.
- Pressure increase of 2,000 psi releases pump down plug. Gives positive displacement indications.

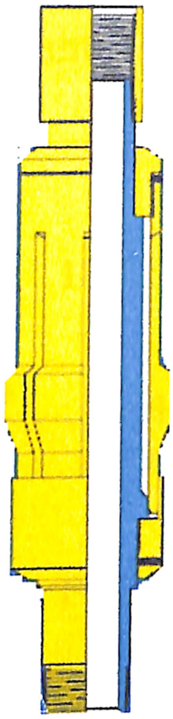


Fig. 5.8

MAIC (Multiple Acting Indicating Collet):

- Allows positive indication of tool position downhole.
- Allows for movement up and down the well by collapsing collet.
- Locates in corresponding indicator sub with upward movement.

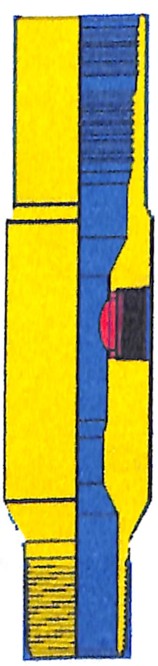
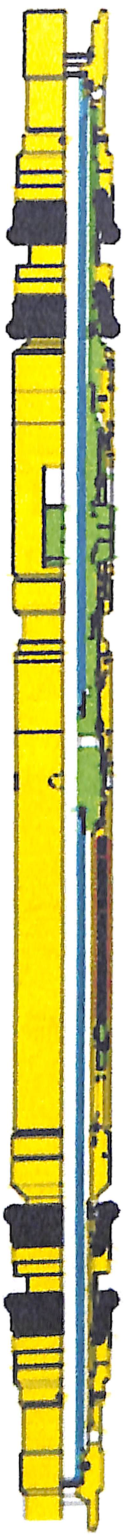


Fig. 5.9

Drain Sub

- Locate above the HMR-HIT and below MAIC.
- 4,250 psi rupture disk standard.
- Allows workstring to pull dry after all ECP's are inflated.

Horizontal Inflation tool (HIT)



HMR HIT-Hydro Mechanical Revised Horizontal Inflation Tool

It selectively inflates multiple External casing packers in a long Horizontal reach wells.

Features:

Heavy Duty Locking Dogs

- Double ramp for smooth movement
- Prevent Tool opening while inside liner.
- Allow set down weight.
- Close tool with upward movement

Spring Assist Closure Mechanism

- Ensure tool is completely closed while inside liner
- Allows downward movement after pressure surges

Cement Control Valve

- Prevents cement from being placed anywhere other than inside ECPs

Constant Annular Bypass

- Prevents swabbing of the well when moving tool
- Prevents sticking of tool while inflating ECP if well has fluid loss.

Fig. 5.10

Reverse Plug Catcher

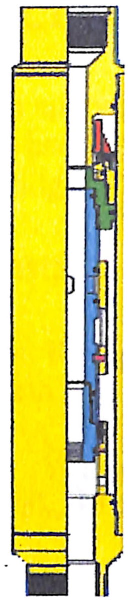


Fig. 5.11

- Locating device for PDP
- 1,200 psi shifts flapper valve to closed position
- Applied pressure acts on flapper
- 2,500 psi opens bypass / reversing ports
- Allows reversing to remove excess inflation cement

ITTS (Inflation Tool Test Sub)

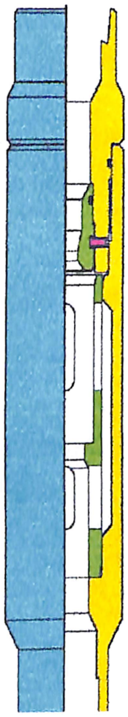


Fig. 5.12

- Provides a means of plugging the workstring for testing or to carry out other hydraulic operations
- Pressure adjustable shear out seat

ECP's inflation procedure:

To apply pressure to the casing to inflate the ECP, the casing must be plugged. This can be accomplished either by a landing collar for ball or pump down plug or by Retrievable Bridge Plug.

Installation of an ECP in Casing String:

- Remove the break off rods if using two stage wiper plug system otherwise retain them.

- A top Handling Sub and bottom sub should be made up and torque to ECP before it is placed on rig floor.

- Apply torque to make up ECP to string. Valve Collar should not rotate relative to Bottom Collar since the twist can damage the Inflatable Element.

Operating Procedures

Single Stage Cementing:

Single stage cementing of ECP is done against a single pump down plug. The procedure is as follows:

- . Calculate volume required to inflate the ECP. This is the volume between the ECP OD and the Open Hole Casing ID for the length of the Element. It is calculated as follows using hole and element size in inches and element length in feet.

ECP Inflation Vol. (BBLS.) = (Hole ID2 - Element OD2) x Element length x .0009714.

- . Pump cement slurry down casing slowing rate to 1 to 2 barrels per minute approximately 5 barrels before the Cement Wiper Plug is calculated to land. Note gauge pressure that has been applied to place cement outside casing. This is balance pressure at the shoe.

- . The Cement Wiper Plug will remove the Break off Rods as it passes through the ECP and expose the valving system to casing pressure.

- . When plug lands, increase pressure to 300-500 psi above balance pressure and hold for 2-5 minutes. Record pressure and volume in displacement tank.

- . Increase surface pressure to balance pressure at the ECP plus shear wire pressure in short quick pump engagements. Each of these pressure increases should be 200-300 psi. Record time, pressure and displacement tank volume at each step. When surface pressure exceeds balance pressure at the ECP + shear wire rating, a pressure decrease is seen. If no pressure decline, continue to increase pressure in 100-200 psi increments or as needed to open Shear Valve. When pressure stabilizes, hold for 2-5 minutes. If the surface pressure dropped below the value calculated to close the Inflation Control Valve, increase pressure to close the ICV, hold for 2-5 minutes. If inflation volume is more than expected, check "Maximum Recommended Differential Pressure" charts to determine if pressure can be increased enough to close the ICV without risk of rupturing the element. Do not exceed "Maximum Recommended Differential Pressure" just to attempt closing the ICV.

If Locking Shear Valve is ran, do not allow casing pressure to fall below 200 psi above balance pressure at the ECP

➢ . Bleed pressure back to the value recorded in above step. Record the time, pressure, and displacement tank volume. The volume missing from the tank from above step is the inflation volume. From this calculate the hole size that the ECP was set in.

Multi stage cementing:

Multi stage selective ECP inflation is carried by the use of HMR HIT. The procedure is as follows:

- After the linear hanger is run and set in the casing locate the test position (located below the lowermost ECP) using the Indicating Collet (provides over-pull when passing through the Indicating Sub in the liner, which is observed on the Weight Indicator at the surface). Snap through the Indicating Sub, noting over pull. The over-pull force required to pass through is available in a range from 5-35 klbs.

- Lower the string back down to place the Indicating Collet below the Indicating Sub. Repeat the indication process as required confirming proper location has been attained. Mark workstring with 5-10 klbs over-pull on the Indicating Sub.

- With the HMR HIT Tool in the test position, apply 1,000 psi differential workstring pressure at the tool to open the Cement Control Valve (CCV) and close off equalizing ports between the cups. Pressure testing must be performed in a blank section of the liner equipped with a Closing Dog Profile Sub, Spacer Sub, and Indicating Sub to allow the CCV to open in the HMR HIT Tool. To confirm that the CCV is opened, bleed off applied workstring pressure (so cups are not moved with pressure on them) and slack off 10K workstring weight on the tool. If the Closing Dogs are extended, the tool will take weight which confirms that the CCV has opened. Re-apply workstring pressure for a time designated by the operator to ensure the Packer Cups are sealing. Make sure the inflation tool is still positioned in blank liner when performing this pressure test or well below the inflation pressure of the ECP if testing across the first ECP.

- After a successful pressure test of the cups, bleed off applied workstring pressure and pick up on the tool to snap through the Indicating Sub and close the CCV. With the HMR HIT tool closed and positioned in a blank pipe section, apply workstring pressure to shear the Ball and Seat in the Inflation Tool Test Sub. This re-establishes circulation through the bottom of the workstring so inflation cement can be spotted to the inflation tool.

□Pick up the workstring until the Indicating Collet engages the Indicating Sub run above the lowermost ECP. Apply tension to pull the Collet through the Indicating Sub, this should require the same force as was observed in the test position

□Including the snap through the Closing Dog Profile Sub. Get a good mark on the drill pipe at this location.

□Install the Dual Wiper Plug into the drill pipe, Mix calculated cement volume required to inflate all ECPs, plus desired excess volume. Excess volume used is job dependent due to hydraulic considerations and operator preference; however, a 100% volume excess is desired whenever possible. Pump weighted post flush behind the inflation cement.

□Displace inflation cement with mud using the cement unit to monitor the volume pumped.

□Slow down pumping when the Inner Wiper Plug is near the RPC. This will prevent a rapid increase in workstring pressure when the plug lands, which may "pressure shock" the RPC into the reversing position prematurely.

□Once indication is seen of plug landing, increase applied pressure at the surface to get a +/-1,000 psi differential at the tool to pressure test the plug seat and shift the flapper closed behind the dart in the RPC. Bleed off pressure.

□Reposition the HMR HIT tool in the Indicator Sub with 5-10 klbs over-pull and apply 1,000 psi workstring pressure to open the cement control valve (CCV) in the HMR HIT tool. Opening of the CCV will not be seen at surface, since the volume is so small. The HMR HIT Tool will open with about 700-900 psi differential pressure at the tool. Bleed off applied workstring pressure so that you don't move the cups with pressure applied.

□Slack off 10K weight on the tool to confirm that the CCV is opened (Closing Dogs extended into the Closing Dog Profile Sub). Once the CCV is confirmed open, apply 500 psi workstring pressure and zero the displacement tank volume and barrel counters.

□Increase applied pressure in rapid 200-300 psi steps to open the SVN in the ECP (usually set at 1,600 or 2,000 psi) and initiate the inflation process. After the SVN opens the HMR HIT Tool does not require a pressure differential to keep the CCV open.

□Monitor workstring pressure decline as the element fills. Surface pressure will stabilize when the element is fully inflated.

□Increase applied inflation pressure to final value (determined by either ICV setting or element pressure rating in the calculated hole size).

□Bleed-Off applied pressure back to the original level that was applied when the displacement tank was zeroed. Make sure fluid is bled into displacement tank used during inflation. Note volume loss and record as the inflation volume. Correlate the volume loss to open hole diameter where the ECP is inflated.

□Hole size = sqrt {Element OD2 + [ECP volume/(Element length x 0.00009714)]}

□Hole Size and Element OD are in inches. ECP volume is in barrels. Element length is in feet.

□Bleed off all applied workstring pressure. Pick up workstring and snap the Indicating Collet through the Indicating Sub and pull the Closing Dogs through Closing Dog Profile to close CCV (trap cement inside workstring) which also opens the equalizing valve between cups on the HMR HIT Tool.

□Move workstring up until the next higher Indicating Sub is engaged with the Indicating Collet. The workstring will have to be pulled "wet" when moving up to the next ECP, due to the RPC being closed (flapper closed).

□Once all ECPs are inflated, pressure up the workstring to 3,500 psi in order to shift the RPC into the reversing position (ports open to allow flow up through the valve). Make sure pressure is applied with HMR in the closed position.

□Switch over pump to the backside to reverse circulate excess cement out of the workstring. If the RPC must hold pressure for a later operation (such as inflating another higher ECP with mud), limit reversing rate to prevent erosion of Flapper Valve Seat in RPC. Reverse out until cement free returns are obtained.

□If reverse circulation is not possible due to formation restrictions, POOH to place HMR inside larger ID casing. Pressure up on workstring to open CCV and circulate out excess cement conventionally.

□Before pulling the workstring out of the hole, the Rupture Disc Drain Valve must be opened to allow the workstring to drain as it is POOH.

□Pull workstring out of the hole at a moderate rate, due to the flow restriction in the bypass through the packer cups, to prevent swabbing the well. If the inflation tool is pulled up into a larger liner when coming out of the hole, pulling speed may be increased.

□After reversing out excess cement, and opening the Drain Valve, run the workstring back down and engage the packer setting dogs with the Liner Top Packer. Apply set down weight to set the packer. Pull the workstring out of the hole.

Cement inflation Vs Mud inflation:

Cement inflation advantages:

- Permanent
- Can perforate through the ECP
- Unaffected by pressure changes when cement is set
- Much less affected by temperature changes than fluid inflated element

Cement inflation disadvantages:

- Particle segregation
- Drilling required through ECP
- Bulk shrinkage maybe a factor
- New mixtures for displacement
- May require new mixing procedure

Mud inflation advantages:

- Easy to use
- No drilling required through ECP
- No special mixture required

Mud inflation disadvantages:

- Inflation pressure directly affected by pressure changes above and below element
- Not permanent

Recommendations for Inflation Fluid

Cement Inflation

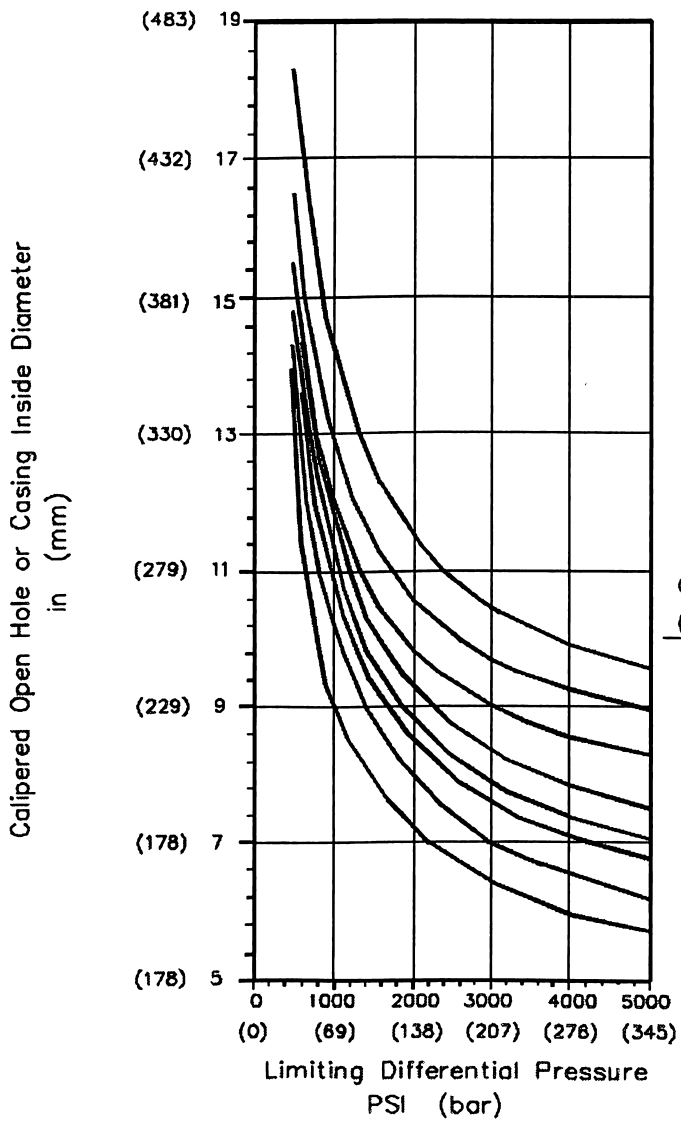
- Permanent seal required
- BHT greater than 200 deg F
- Application requires differential pressure rating higher than ECP rating
- 20' or 40' for all critical installations

Mud Inflation

- Temporary seal required
- BHT less than 200 deg F
- Pressure differential will never exceed ECP rating
- No H2S or other damaging fluid contact of element over the life of the application.

Differential pressure curves and allowable pumping volume for ECP inflation

The amount of differential/inflation pressure that an ECP can withstand varies with the hole size and casing rating. The ECP differential pressure curves show the pressure rating of each tool for different size holes. The curves give the pressure limitation of the Inflatable Element only. Since the inflate pressure applies a collapse pressure to the ECP Mandrel, the inflation pressure may be limited by the strength ratings of the mandrel and the hydrostatic pressure.

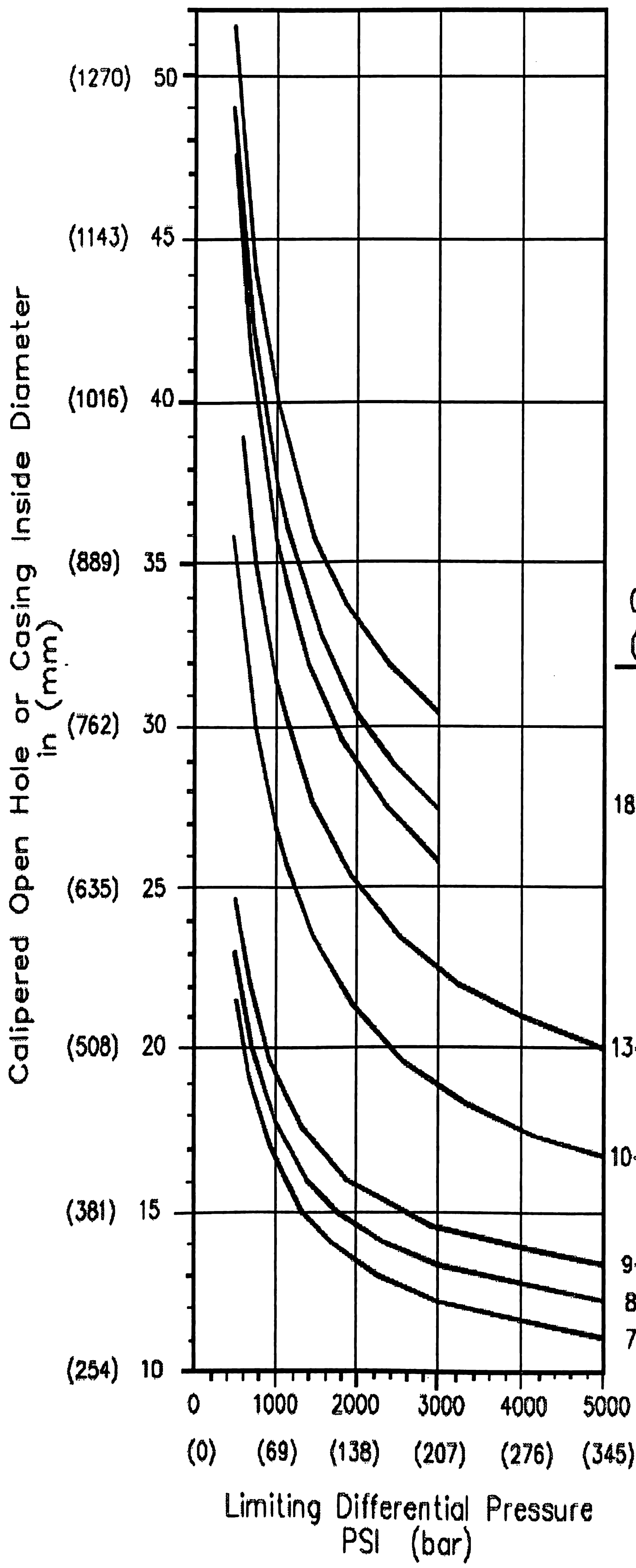


The charts indicate a round hole with no extraneous stresses. Loadings that approach the curve are not generally recommended.

Casing Size (in)	Casing Size (mm)	Tool O.D. (in)	Tool O.D. (mm)
7	117,8	8.00	203,2
6-5/8	168,3	7.63	193,7
5-1/2	139,7	7.00	117,8
5	127,0	6.00	152,4
4-1/2	114,3	5.63	142,9
4	101,6	5.25	133,4
2-7/8	73,0	4.25	108,0
3-1/2	88,9	4.30	109,2

Fig. 5.13 Differential pressure curves

The charts indicate a round hole with no extraneous stresses. Loadings that approach the curve are not generally recommended.



Casing Size (in)	Casing Size (mm)	Tool O.D. (in)	Tool O.D. (mm)
20	508,0	24.00	609,6
18-5/8	473,1	21.50	546,1
16	406,4	18.50	469,9
13-3/8	339,7	15.75	400,1
10-3/4	273,0	12.75	323,9
9-5/8	224,5	11.25	285,8
8-5/8	219,1	10.13	257,2
7-5/8	193,7	9.00	228,6

Fig. 5.14

Operations tabulated "Maximum Recommended Differential Pressures & volume of cement to be pumped in"

Table 5.1 3 ½" Casing/ 4.3" OD ECP

Hole Size (in.)	PSI	Bar	Inf Vol (bbl/ft)	Vol (bbls)			
				7'	10'	20'	40'
4-3/4	2600	179	0.004	0.03	0.04	0.08	0.16
5	2600	179	0.006	0.04	0.06	0.13	0.25
5-1/4	2400	166	0.009	0.06	0.09	0.18	0.35
5-1/2	2100	145	0.011	0.08	0.11	0.23	0.46
5-3/4	1800	124	0.014	0.10	0.14	0.28	0.57
6	1600	110	0.017	0.12	0.17	0.34	0.68
6-1/4	1400	97	0.020	0.14	0.20	0.40	0.80
6-1/2	1200	83	0.023	0.16	0.23	0.46	0.92
6-3/4	1000	69	0.026	0.18	0.26	0.53	1.05
7	800	55	0.030	0.21	0.30	0.59	1.19
7-1/4	600	41	0.033	0.23	0.33	0.66	1.32
* 7-1/2	400	28	0.037	0.26	0.37	0.73	1.47
* 7-3/4	400	28	0.040	0.28	0.40	0.81	1.62
** 8	400	28	0.044	0.31	0.44	0.88	1.77
** 8-1/4	400	28	0.048	0.34	0.48	0.96	1.93
** 8-1/2	400	28	0.052	0.37	0.52	1.04	2.09
** 8-3/4	400	28	0.056	0.39	0.56	1.13	2.26
** 9	400	28	0.061	0.43	0.61	1.21	2.43
** 10	300	21	0.079	0.55	0.79	1.58	3.17
** 11	300	21	0.100	0.70	1.00	1.99	3.98
** 12	300	21	0.122	0.85	1.22	2.44	4.88

Table 5.2 4 ½" casing/ 5- 5/8 OD ECP

Hole Size (in.)	PSI	Bar	Inf Vol (bbl/ft)	Vol (bbls)			
				7'	10'	20'	40'
6-1/8	2800	193	0.006	0.04	0.06	0.11	0.23
6-1/4	2600	179	0.007	0.05	0.07	0.14	0.29
6-1/2	2400	166	0.010	0.07	0.10	0.21	0.41
6-3/4	2100	145	0.014	0.09	0.14	0.27	0.54
7	1800	124	0.017	0.12	0.17	0.34	0.67
7-1/4	1600	110	0.020	0.14	0.20	0.41	0.81
* 7-1/2	1400	97	0.024	0.17	0.24	0.48	0.96
* 7-3/4	1200	83	0.028	0.19	0.28	0.55	1.10
* 7-7/8	1000	69	0.030	0.21	0.30	0.59	1.18
** 8	800	55	0.031	0.22	0.31	0.63	1.26
** 8-1/4	600	41	0.035	0.25	0.35	0.71	1.42
** 8-1/2	400	28	0.039	0.28	0.39	0.79	1.58
** 8-3/4	400	28	0.044	0.31	0.44	0.87	1.75
** 9	400	28	0.048	0.34	0.48	0.96	1.92
** 9-1/4	400	28	0.052	0.37	0.52	1.05	2.10
** 9-1/2	400	28	0.057	0.40	0.57	1.14	2.28
** 10	400	28	0.066	0.46	0.66	1.33	2.66
** 11	300	21	0.087	0.61	0.87	1.74	3.47
** 12	300	21	0.109	0.76	1.09	2.18	4.37
** 13	300	21	0.133	0.93	1.33	2.67	5.34
** 14	300	21	0.160	1.12	1.60	3.19	6.39

Table 5.3 4" casing/ 5-1/4"OD ECP

Hole Size (in.)	PSI	Bar	Inf Vol (bbl/ft)	Vol (bbls)			
				7'	10'	20'	40'
5-3/4	2600	179	0.005	0.04	0.05	0.11	0.21
6	2500	172	0.008	0.06	0.08	0.16	0.33
6-1/4	2200	152	0.011	0.08	0.11	0.22	0.45
6-1/2	2000	138	0.014	0.10	0.14	0.29	0.57
6-3/4	1700	117	0.017	0.12	0.17	0.35	0.70
7	1500	103	0.021	0.15	0.21	0.42	0.83
7-1/4	1300	90	0.024	0.17	0.24	0.49	0.97
7-1/2	1200	83	0.028	0.20	0.28	0.56	1.11
7-3/4	1000	69	0.032	0.22	0.32	0.63	1.26
8	800	55	0.035	0.25	0.35	0.71	1.42
8-1/4	600	41	0.039	0.28	0.39	0.79	1.57
* 8-1/2	500	34	0.043	0.30	0.43	0.87	1.74
* 8-3/4	400	28	0.048	0.33	0.48	0.95	1.90
** 9	400	28	0.052	0.36	0.52	1.04	2.08
** 9-1/4	400	28	0.056	0.39	0.56	1.13	2.25
** 9-1/2	400	28	0.061	0.43	0.61	1.22	2.44
** 10	300	21	0.070	0.49	0.70	1.41	2.81
** 11	300	21	0.091	0.64	0.91	1.82	3.63
** 12	300	21	0.113	0.79	1.13	2.26	4.52
** 13	300	21	0.137	0.96	1.37	2.75	5.50
** 14	300	21	0.164	1.15	1.64	3.27	6.54

Table 5.4 4-1/2" casing/6"OD ECP

Hole Size (in.)	PSI	Bar	Inf Vol (bbl/ft)	Vol (bbls)			
				7'	10'	20'	40'
6-1/2	2600	179	0.006	0.04	0.06	0.12	0.24
6-3/4	2600	179	0.009	0.07	0.09	0.19	0.37
7	2400	166	0.013	0.09	0.13	0.25	0.51
7-1/4	2100	145	0.016	0.11	0.16	0.32	0.64
7-1/2	1800	124	0.020	0.14	0.20	0.39	0.79
7-3/4	1600	110	0.023	0.16	0.23	0.47	0.93
8	1400	97	0.027	0.19	0.27	0.54	1.09
8-1/4	1200	83	0.031	0.22	0.31	0.62	1.25
8-1/2	1000	69	0.035	0.25	0.35	0.70	1.41
8-3/4	800	55	0.039	0.28	0.39	0.79	1.58
9	600	41	0.044	0.31	0.44	0.87	1.75
* 9-1/4	400	28	0.048	0.34	0.48	0.96	1.93
* 9-1/2	400	28	0.053	0.37	0.53	1.05	2.11
** 9-3/4	400	28	0.057	0.40	0.57	1.15	2.29
** 10	400	28	0.062	0.44	0.62	1.24	2.49
** 11	400	28	0.083	0.58	0.83	1.65	3.30
** 12	300	21	0.105	0.73	1.05	2.10	4.20
** 13	300	21	0.129	0.90	1.29	2.58	5.17
** 14	300	21	0.155	1.09	1.55	3.11	6.22

Table 5.5 5" casing/6"OD ECP

Hole Size (in.)	PSI	Bar	Inf Vol (bbl/ft)	Vol (bbls)			
				7'	10'	20'	40'
6-1/2	2600	179	0.006	0.04	0.06	0.12	0.24
6-3/4	2600	179	0.009	0.07	0.09	0.19	0.37
7	2300	159	0.013	0.09	0.13	0.25	0.51
7-1/4	2100	145	0.016	0.11	0.16	0.32	0.64
7-1/2	1800	124	0.020	0.14	0.20	0.39	0.79
7-3/4	1600	110	0.023	0.16	0.23	0.47	0.93
7-7/8	1400	97	0.025	0.18	0.25	0.51	1.01
* 8	1300	90	0.027	0.19	0.27	0.54	1.09
* 8-1/4	1100	76	0.031	0.22	0.31	0.62	1.25
** 8-1/2	800	55	0.035	0.25	0.35	0.70	1.41
** 8-3/4	600	41	0.039	0.28	0.39	0.79	1.58
** 9	500	34	0.044	0.31	0.44	0.87	1.75
** 9-1/4	500	34	0.048	0.34	0.48	0.96	1.93
** 9-1/2	500	34	0.053	0.37	0.53	1.05	2.11
** 10	500	34	0.062	0.44	0.62	1.24	2.49
** 11	400	28	0.083	0.58	0.83	1.65	3.30
** 12	400	28	0.105	0.73	1.05	2.10	4.20
** 13	300	21	0.129	0.90	1.29	2.58	5.17
** 14	300	21	0.155	1.09	1.55	3.11	6.22

Table 5.6 5-1/2" casing/6"OD ECP

Hole Size (in.)	PSI	Bar	Inf Vol (bbl/ft)	Vol (bbls)			
				7'	10'	20'	40'
7-1/2	2800	193	0.007	0.05	0.07	0.14	0.28
7-3/4	2700	186	0.011	0.08	0.11	0.21	0.43
7-7/8	2600	179	0.013	0.09	0.13	0.25	0.51
8	2400	166	0.015	0.10	0.15	0.29	0.58
8-1/4	2200	152	0.019	0.13	0.19	0.37	0.74
* 8-1/2	2000	138	0.023	0.16	0.23	0.45	0.90
* 8-3/4	1800	124	0.027	0.19	0.27	0.54	1.07
** 9	1600	110	0.031	0.22	0.31	0.62	1.24
** 9-1/4	1400	97	0.036	0.25	0.36	0.71	1.42
** 9-1/2	1200	83	0.040	0.28	0.40	0.80	1.60
** 9-3/4	1100	76	0.045	0.31	0.45	0.89	1.79
** 10	1000	69	0.050	0.35	0.50	0.99	1.98
** 10-1/4	900	62	0.054	0.38	0.54	1.09	2.18
** 10-1/2	800	55	0.059	0.42	0.59	1.19	2.38
** 11	700	48	0.070	0.49	0.70	1.40	2.80
** 12	600	41	0.092	0.65	0.92	1.85	3.69
** 13	500	34	0.117	0.82	1.17	2.33	4.66
** 14	500	34	0.143	1.00	1.43	2.86	5.71
** 15	400	28	0.171	1.20	1.71	3.42	6.84
** 16	300	21	0.201	1.41	2.01	4.02	8.04
** 17	300	21	0.233	1.63	2.33	4.66	9.33

Table 5.7 5" casing/7" OD ECP

Hole Size (in.)	PSI	Bar	Inf Vol (bbl/ft)	Vol (bbls)			
				7'	10'	20'	40'
7-1/2	2800	193	0.007	0.05	0.07	0.14	0.28
7-3/4	2700	186	0.011	0.08	0.11	0.21	0.43
7-7/8	2600	179	0.013	0.09	0.13	0.25	0.51
8	2400	166	0.015	0.10	0.15	0.29	0.58
8-1/4	2200	152	0.019	0.13	0.19	0.37	0.74
*8-1/2	2000	138	0.023	0.16	0.23	0.45	0.90
*8-3/4	1800	124	0.027	0.19	0.27	0.54	1.07
**9	1600	110	0.031	0.22	0.31	0.62	1.24
**9-1/4	1400	97	0.036	0.25	0.36	0.71	1.42
**9-1/2	1200	83	0.040	0.28	0.40	0.80	1.60
**9-3/4	1100	76	0.045	0.31	0.45	0.89	1.79
**10	1000	69	0.050	0.35	0.50	0.99	1.98
**10-1/4	900	62	0.054	0.38	0.54	1.09	2.18
**10-1/2	800	55	0.059	0.42	0.59	1.19	2.38
**11	700	48	0.070	0.49	0.70	1.40	2.80
**12	600	41	0.092	0.65	0.92	1.85	3.69
**13	500	34	0.117	0.82	1.17	2.33	4.66
**14	500	34	0.143	1.00	1.43	2.86	5.71
**15	400	28	0.171	1.20	1.71	3.42	6.84
**16	300	21	0.201	1.41	2.01	4.02	8.04
**17	300	21	0.233	1.63	2.33	4.66	9.33

Table 5.8 5-1/2" casing/7-3/4" OD ECP

Hole Size (in.)	PSI	Bar	Inf Vol (bbl/ft)	Vol (bbls)			
				7'	10'	20'	40'
8-1/4	2800	193	0.008	0.05	0.08	0.16	0.31
8-1/2	2700	186	0.012	0.08	0.12	0.24	0.47
* 8-3/4	2600	179	0.016	0.11	0.16	0.32	0.64
* 9	2500	172	0.020	0.14	0.20	0.41	0.81
* 9-1/4	2400	166	0.025	0.17	0.25	0.50	0.99
** 9-1/2	2200	152	0.029	0.21	0.29	0.59	1.17
** 9-3/4	2000	138	0.034	0.24	0.34	0.68	1.36
** 10	1800	124	0.039	0.27	0.39	0.78	1.55
** 10-1/4	1600	110	0.044	0.31	0.44	0.87	1.75
** 10-1/2	1400	97	0.049	0.34	0.49	0.98	1.95
** 10-3/4	1200	83	0.054	0.38	0.54	1.08	2.16
** 11	1100	76	0.059	0.41	0.59	1.18	2.37
** 11-1/4	1000	69	0.065	0.45	0.65	1.29	2.58
** 11-1/2	900	62	0.070	0.49	0.70	1.40	2.81
** 12	700	48	0.082	0.57	0.82	1.63	3.26
** 13	600	41	0.106	0.74	1.06	2.12	4.23
** 14	500	34	0.132	0.92	1.32	2.64	5.28
** 15	500	34	0.160	1.12	1.60	3.20	6.41
** 16	400	28	0.190	1.33	1.90	3.81	7.61
** 17	300	21	0.222	1.56	2.22	4.45	8.90
** 18	300	21	0.256	1.79	2.56	5.13	10.26

Table 5.9 6-5/8" casing/7-5/8" OD ECP

Hole Size (in.)	PSI	Bar	Inf Vol (bbl/ft)	Vol (bbls)			
				7'	10'	20'	40'
7-7/8	2600	179	0.004	0.03	0.04	0.08	0.15
8	2600	179	0.006	0.04	0.06	0.11	0.23
8-1/4	2600	179	0.010	0.07	0.10	0.19	0.39
8-1/2	2600	179	0.014	0.10	0.14	0.27	0.55
8-3/4	2400	166	0.018	0.13	0.18	0.36	0.72
9	2200	152	0.022	0.16	0.22	0.44	0.89
9-1/4	2000	138	0.027	0.19	0.27	0.53	1.07
* 9-1/2	1800	124	0.031	0.22	0.31	0.62	1.25
* 9-3/4	1600	110	0.036	0.25	0.36	0.72	1.43
* 9-7/8	1500	103	0.038	0.27	0.38	0.76	1.53
* 10	1400	97	0.041	0.28	0.41	0.81	1.63
* 10-1/4	1200	83	0.046	0.32	0.46	0.91	1.82
** 10-1/2	900	62	0.051	0.35	0.51	1.01	2.02
** 10-3/4	700	48	0.056	0.39	0.56	1.12	2.23
** 11	500	34	0.061	0.43	0.61	1.22	2.44
** 11-1/4	500	34	0.066	0.47	0.66	1.33	2.66
** 11-1/2	500	34	0.072	0.50	0.72	1.44	2.88
** 11-3/4	400	28	0.078	0.54	0.78	1.55	3.11
** 12	400	28	0.083	0.58	0.83	1.67	3.34
** 13	400	28	0.108	0.75	1.08	2.15	4.31
** 14	300	21	0.134	0.94	1.34	2.68	5.36
** 15	300	21	0.162	1.13	1.62	3.24	6.48
** 16	300	21	0.192	1.35	1.92	3.84	7.69

Table 5.10 7"casing/8-1/8" OD ECP

Hole Size (in.)	PSI	Bar	Inf Vol (bbl/ft)	Vol (bbls)			
				7'	10'	20'	40'
8-1/2	2600	179	0.006	0.04	0.06	0.12	0.24
8-3/4	2600	179	0.010	0.07	0.10	0.21	0.41
9	2300	159	0.015	0.10	0.15	0.29	0.58
9-1/4	2200	152	0.019	0.13	0.19	0.38	0.76
9-1/2	2000	138	0.024	0.16	0.24	0.47	0.94
9-3/4	1700	117	0.028	0.20	0.28	0.56	1.13
9-7/8	1600	110	0.031	0.21	0.31	0.61	1.22
10	1500	103	0.033	0.23	0.33	0.66	1.32
* 10-1/4	1300	90	0.038	0.27	0.38	0.76	1.52
* 10-1/2	1100	76	0.043	0.30	0.43	0.86	1.72
* 10-3/4	900	62	0.048	0.34	0.48	0.96	1.93
** 11	700	48	0.053	0.37	0.53	1.07	2.14
** 11-1/4	500	34	0.059	0.41	0.59	1.18	2.35
** 11-1/2	400	28	0.064	0.45	0.64	1.29	2.57
** 11-3/4	400	28	0.070	0.49	0.70	1.40	2.80
** 12	400	28	0.076	0.53	0.76	1.52	3.03
** 13	400	28	0.100	0.70	1.00	2.00	4.00
** 14	300	21	0.126	0.88	1.26	2.53	5.05
** 15	300	21	0.154	1.08	1.54	3.09	6.18
** 16	300	21	0.185	1.29	1.85	3.69	7.38
** 17	300	21	0.217	1.52	2.17	4.33	8.66

Table 5.11 7" casing/ 8"OD ECP

Hole Size (in.)	PSI	Bar	Inf Vol (bbl/ft)	Vol (bbls)			
				7'	10'	20'	40'
8-1/2	2600	179	0.008	0.06	0.08	0.16	0.32
8-3/4	2600	179	0.012	0.09	0.12	0.24	0.49
9	2300	159	0.017	0.12	0.17	0.33	0.66
9-1/4	2200	152	0.021	0.15	0.21	0.42	0.84
9-1/2	2000	138	0.025	0.18	0.25	0.51	1.02
9-3/4	1700	117	0.030	0.21	0.30	0.60	1.21
9-7/8	1600	110	0.033	0.23	0.33	0.65	1.30
10	1500	103	0.035	0.24	0.35	0.70	1.40
* 10-1/4	1300	90	0.040	0.28	0.40	0.80	1.60
* 10-1/2	1100	76	0.045	0.31	0.45	0.90	1.80
* 10-3/4	900	62	0.050	0.35	0.50	1.00	2.00
** 11	700	48	0.055	0.39	0.55	1.11	2.21
** 11-1/4	500	34	0.061	0.43	0.61	1.22	2.43
** 11-1/2	400	28	0.066	0.46	0.66	1.33	2.65
** 11-3/4	400	28	0.072	0.50	0.72	1.44	2.88
** 12	400	28	0.078	0.54	0.78	1.55	3.11
** 13	400	28	0.102	0.71	1.02	2.04	4.08
** 14	300	21	0.128	0.90	1.28	2.56	5.13
** 15	300	21	0.156	1.09	1.56	3.13	6.26
** 16	300	21	0.187	1.31	1.87	3.73	7.46
** 17	300	21	0.219	1.53	2.19	4.37	8.74

Table 5.12 7-5/8" casing/9" OD ECP

Hole Size (in.)	PSI	Bar	Inf Vol (bbl/ft)	Vol (bbls)			
				7'	10'	20'	40'
9-1/2	2600	179	0.009	0.06	0.09	0.18	0.36
9-3/4	2600	179	0.014	0.10	0.14	0.27	0.55
9-7/8	2500	172	0.016	0.11	0.16	0.32	0.64
10	2400	166	0.018	0.13	0.18	0.37	0.74
10-1/4	2200	152	0.023	0.16	0.23	0.47	0.93
10-1/2	2000	138	0.028	0.20	0.28	0.57	1.14
10-3/4	1800	124	0.034	0.24	0.34	0.67	1.34
* 11	1500	103	0.039	0.27	0.39	0.78	1.55
* 11-1/4	1400	97	0.044	0.31	0.44	0.89	1.77
* 11-1/2	1100	76	0.050	0.35	0.50	1.00	1.99
* 11-3/4	800	55	0.055	0.39	0.55	1.11	2.22
** 12	700	48	0.061	0.43	0.61	1.22	2.45
** 12-1/4	500	34	0.067	0.47	0.67	1.34	2.68
** 12-1/2	400	28	0.073	0.51	0.73	1.46	2.92
** 12-3/4	400	28	0.079	0.55	0.79	1.58	3.17
** 13	400	28	0.085	0.60	0.85	1.71	3.42
** 13-1/4	400	28	0.092	0.64	0.92	1.84	3.67
** 13-1/2	400	28	0.098	0.69	0.98	1.97	3.93
** 13-3/4	400	28	0.105	0.73	1.05	2.10	4.20
** 14	400	28	0.112	0.78	1.12	2.23	4.47
** 15	400	28	0.140	0.98	1.40	2.80	5.60
** 16	300	21	0.170	1.19	1.70	3.40	6.80
** 17	300	21	0.202	1.41	2.02	4.04	8.08
** 18	300	21	0.236	1.65	2.36	4.72	9.44
** 19	300	21	0.251	1.76	2.51	5.02	10.88

Table 5.13 8-5/8"casing/10-1/8" OD ECP

Hole Size (in.)	PSI	Bar	Inf Vol (bbl/ft)	Vol (bbls)			
				7'	10'	20'	40'
10-5/8	2600	179	0.010	0.07	0.10	0.20	0.40
10-3/4	2600	179	0.013	0.09	0.13	0.25	0.51
11	2600	179	0.018	0.13	0.18	0.36	0.72
11-1/4	2500	172	0.023	0.16	0.23	0.47	0.93
11-1/2	2300	159	0.029	0.20	0.29	0.58	1.16
11-3/4	2100	145	0.035	0.24	0.35	0.69	1.38
12	2000	138	0.040	0.28	0.40	0.81	1.61
12-1/4	1800	124	0.046	0.32	0.46	0.92	1.85
* 12-1/2	1700	117	0.052	0.37	0.52	1.04	2.09
* 12-3/4	1500	103	0.058	0.41	0.58	1.17	2.33
* 13	1300	90	0.065	0.45	0.65	1.29	2.58
** 13-1/4	1200	83	0.071	0.50	0.71	1.42	2.84
** 13-1/2	1000	69	0.077	0.54	0.77	1.55	3.10
** 13-3/4	800	55	0.084	0.59	0.84	1.68	3.36
** 14	700	48	0.091	0.64	0.91	1.82	3.63
** 14-1/4	600	41	0.098	0.68	0.98	1.95	3.91
** 14-1/2	600	41	0.105	0.73	1.05	2.09	4.19
** 14-3/4	600	41	0.112	0.78	1.12	2.24	4.47
** 15	400	28	0.119	0.83	1.19	2.38	4.76
** 15-1/2	400	28	0.134	0.94	1.34	2.68	5.35
** 16	400	28	0.149	1.04	1.49	2.98	5.96
** 17	400	28	0.181	1.27	1.81	3.62	7.25
** 18	300	21	0.215	1.51	2.15	4.30	8.61
** 19	300	21	0.272	1.90	2.72	5.44	10.04
** 20	300	21	0.289	2.02	2.88	5.78	11.56
** 21	300	21	0.329	2.30	3.29	6.58	13.15

Table 5.14 9-5/8" casing/11-1/4" OD ECP

Hole Size (in.)	PSI	Bar	Inf. Vol (bbl/ft)	Vol (bbls)			
				7'	10'	20'	40'
12	2600	179	0.017	0.12	0.17	0.34	0.68
12-1/4	2600	179	0.023	0.16	0.23	0.46	0.91
12-1/2	2500	172	0.029	0.20	0.29	0.58	1.15
12-3/4	2300	159	0.035	0.24	0.35	0.70	1.40
13	2200	152	0.041	0.29	0.41	0.82	1.65
* 13-1/4	2100	145	0.048	0.33	0.48	0.95	1.90
* 113-1/2	2000	138	0.054	0.38	0.54	1.08	2.16
* 113-3/4	1800	124	0.061	0.43	0.61	1.21	2.43
* 114	1600	110	0.067	0.47	0.67	1.35	2.70
* 114-1/4	1500	103	0.074	0.52	0.74	1.49	2.97
* 114-1/2	1300	90	0.081	0.57	0.81	1.63	3.25
* 114-3/4	1200	83	0.088	0.62	0.88	1.77	3.54
* 115	1000	69	0.096	0.67	0.96	1.91	3.82
* 115-1/4	900	62	0.103	0.72	1.03	2.06	4.12
** 15-1/2	700	48	0.110	0.77	1.10	2.21	4.42
** 15-3/4	600	41	0.118	0.83	1.18	2.36	4.72
** 16	600	41	0.126	0.88	1.26	2.51	5.03
** 16-1/4	500	34	0.134	0.93	1.34	2.67	5.34
** 16-1/2	500	34	0.142	0.99	1.42	2.83	5.66
** 16-3/4	500	34	0.150	1.05	1.50	2.99	5.98
** 17	500	34	0.158	1.10	1.58	3.16	6.31
** 17-1/4	400	28	0.166	1.16	1.66	3.32	6.64
** 18	400	28	0.192	1.34	1.92	3.84	7.67
** 19	400	28	0.228	1.59	2.28	4.55	9.11
** 20	400	28	0.266	1.86	2.66	5.31	10.62
** 21	300	21	0.305	2.14	3.05	6.11	12.22
** 22	300	21	0.347	2.43	3.47	6.94	13.89
** 23	300	21	0.391	2.73	3.91	7.82	15.64

Material of the packing element:

Nitrile elastomers are generally used for making the packing element of an ECP.

Chemical name: Butadiene- Acrylonitrile

Basic characteristics: Good Physical strength, good oil and water resistance, working temperature range of -30oF to 250oF which can be stretched to 300oF for some applications.

Structure:
Butadiene Acrylonitrile (-CH2-CH=CH-CH2)---- (-CH2-CH-) | C=N← Nitrile Group
Nitrile has a fairly good oil resistance due to the nitrile group. Usually, there is about 33% to 41% by weight of the acrylonitrile in the polymer. The nitrile group is very efficient in repelling oil and water. As the nitrile content increases, resistance to petroleum base oils and hydrocarbon fuels increases, but low temperature flexibility decreases. Nitrile compounds are superior to most elastomers with regard to compression set, tear, and abrasion resistance. The weak point in the polymer is the doubled bond. The double bond is also susceptible to be attack by other chemicals such as H2S, acids and amines causing some of the physical changes in parts we have seen after use. In addition, at around 325-350oF the double bond becomes somewhat unstable and tries to rearrange itself to a more stable condition. The subsequent change in the physical form, brittleness, and loss of fracture strength is the result.

ECP's installation in India

In India up till now the sole ECP providers are Baker Oil Tools, Baker Hughes. It has successfully installed more than 180 ECP's in British Gas Panna field (Bombay High) in the last four years in two phases. All of these ECP's were run in horizontal wells in carbonate reservoir of Bombay High, since cementation in such highly deviated wells is a major problem. The reason for most of the installations in British Gas, Panna Field is the layered structure of this reservoir having an upper gas bearing horizon and lower oil bearing and most of the wells are inclined at an angle of about 90^0. Two installations are also done in ONGC that two in the Bombay high.

Reactive Core Packers

Description

The Reactive Core Packer (RCPacker) is a primary non-cemented zonal isolation packer that combines the instant setting features of the External Casing Packer (ECP) with the long term isolation of the Reactive Core technology.

The RCPacker has all of the functionality of the standard XTREMEZONE ECP including the dual inflation valve system, the reinforced non-continuous steel ribs at each end of the element and the composite reinforcements that make this packer especially robust. The addition of these components allows the RCPacker to seal in non-gauge or oval holes.

The packer is built with a swellable inner core based on the Reactive Element Technology. The use of the swelling core makes this a viable option for immediate zonal isolation without the need to pump cement.

Once the element is inflated with water, the Reactive Core begins to take up the inflated volume by way of osmotic swelling. Once fully swollen, the packer will have a rigid core capable of holding pressure over the life of the well.

Features and Benefits

- Immediate seal by inflation – positive indication of isolation
- Reactive core eliminates the needs to inflate with cement – reduced risk
- No volume loss during swelling of core -
- Composite end sections – provide consistent high performance oval and irregular hole shapes
- Redundant 4 valve system (patented feature) – ensures the element inflation is not compromised by pumping dirty fluids
- Progressive inflation from bottom to top (patented feature) – Eliminates trapped fluid in annulus allowing complete inflation.
- Premium thread connections available upon request
- One trip deployment and activation.
- Applicable in oil, gas or water injection wells.
- Utilizes proven design features of XTremeZone Packer
- Swelling layer protected by inflatable element.
- Inflation medium combines with inner layer to form a solid elastomer core.

How RCPacker different from the ECP

The differentiating factor of the RCPacker between the standard External Casing Packers is that the RCPacker has a reactive element built underneath the inflatable element that provides the ability of the packer to take up the inflation fluid volume until the core is fully swollen.

The benefits of this are that there is no longer the need to cement inflate in order to get a long-term seal. The reactive core comes with a water reactive compound as the standard material. This elastomer requires water exposure to swell and expand the volume of the core.
For this reason, the RCPacker must be inflated with a fresh water fluid with little to no solids content. While the packer can be run in most any fluids, it is recommended that during the inflation stage, a fresh water slug be placed across the packer to ensure the fluid going into the packer is as fresh as possible.
Once the inflatable element is filled and the valves have isolated flow from the casing ID to the element, the reactive core begins to swell and take up the fluid volume. The time to swell to the full volume depends on a number of factors in the well mainly temperature and fluid salinity. Additionally, the pressure rating for the RCPacker is dependent on the setting hole ID (which reflects the volumetric swell required)

How the RCPacker Improves Production Control

An outer element is simply inflated and the proprietary core reacts with the inflation fluid to form a permanent seal that is largely unaffected by down hole pressure or temperature changes. Used together, the RCPacker and Baker Oil Tools' EQUALIZER Inflow Control Device can efficiently manage flow in the annulus. Sections of the production interval between RCPacker can be shut off using an isolation straddle system.

RCPacker System:

There is concern for problems caused by uncontrolled fluid flow in the annulus of an openhole completion. To provide points of isolation in the open-hole annulus, the RCPacker is run on the production liner string. The packer is inflated simply by either applying pressure to the
Casing/liner string or by positioning an inflation tool across the packer and applying pressure directly to the valve system. Once the element is inflated, the core of the RCPacker reacts with the inflation fluid to form a permanent seal.

General Deployment System:

1. Drill through production interval.
2. Run production liner with RCPacker positioned as desired.
3. Set and release liner hanger.
4. Set RCPacker by either of the following methods:
    a. Applying differential pressure inside the liner.

b. Pull inner string with cup tool to position cup tool at each RCPacker and apply pressure down the work string to cup tool to activate and set the packers.

5. Produce as required.

RCPacker Open-Hole Packer System:

Cup Inflation Tool

The Cup Inflation Tool is designed to selectively inflate the RCPacker. The Cup Inflation Tool may be used to manipulate a Hydraulic Cement Sliding Sleeve (HCSS) to perform a stage cement job above the uppermost RCPacker if a HCSS shifting tool is used. Two upward facing cups and two downward facing cups provide isolation to the injection port; a micro-annulus between the cups and the inner mandrels provides a path for annular fluids when circulating and to prevent swabbing when moving the tool.

Features/Benefits

- Shifting collet - manipulates HCSS valve if shifting tool is used
- Opposing cups - isolate inflation pressure and cement
- Annular bypass - provides free fluid movement in annulus
- Simple design - allows easy operation and redress
- Spacing between cups - allows easy location of RCPacker and HCSS

OPERATION:

To provide points of isolation in the open-hole annulus, the Reactive Core Packer is run on the production liner string. The RCPacker is inflated with well bore fluid simply by either applying pressure to the casing or liner string or by positioning an inflation tool across the packer and applying pressure directly to the valve system. Once the element is inflated, the core of the RCPacker reacts with the inflation fluid to form a permanent seal.

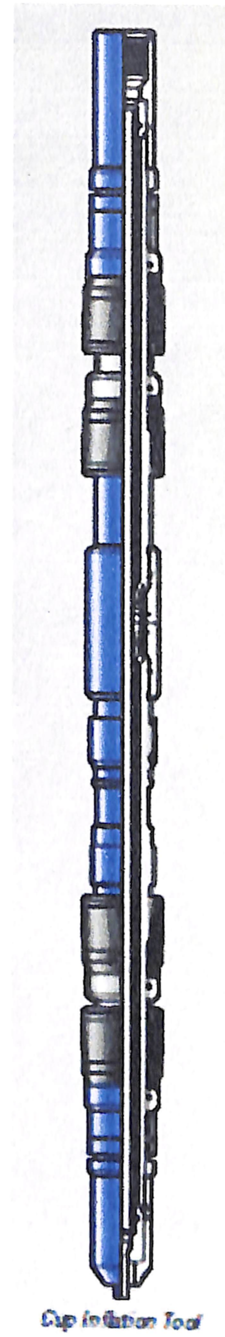


Fig. 6.1 Cup Inflation Tool

Pressure And Shear Wire Chart

Shear Valve, Locking Shear Valve, and Inflation Control Valve

Precut 3/4" Long Brass Wire			
Shear Wire Dia	**Wire Gage Size**	**PSI ***	**Material No.**
.040	18	575	H04-00467-01
.045	17	750	H04-00467-02
.051	16	1000	H04-00467-03
.057	15	1250	H04-00467-04
.064	14	1600	H04-00467-05
.072	13	2000	H04-00467-06
.081	12	2600	H04-00467-07

* Tolerance +150 psi, - 0 psi

Precut 12" Long Brass Wire			
Shear Wire Dia	**Wire Gage Size**	**PSI***	**Material No.**
.040	18	575	H04-18610-01
.045	17	750	H04-18610-02
.051	16	1000	H04-18610-03
.057	15	1250	H04-18610-04
.064	14	1600	H04-18610-05
.072	13	2000	H04-18610-06
.081	12	2600	H04-18610-07

* Tolerance +150 psi, - 0 psi

Table 6.1

"MPas" Mechanical External Casing Packer System

Introduction

The MPas packer is the industries only non inflatable mechanical packer that conforms to irregular wellbore geometries. The new product which has performed successfully in more than 1,009 runs, has proven reliable for selective wellbore isolation in horizontal open hole completions without the risk and cost associated with cementing and perforating. The "MPas" Mechanical Packer System is a primary cementing and zone isolation packer utilizing a Non-Inflatable Packing Element run as an integral part of the casing string to provide a seal between the casing and wellbore. The "MPas" External Casing Packer (ECP) has an elastomeric element with composite structure which is set mechanically by shifting a Balance Sleeve allowing wellbore hydrostatic pressure to flood an atmospheric chamber and apply setting force to the Non-Inflatable Element. The element is hydrostatic set by mechanically shifting a sleeve and then mechanically locked eliminating the requirement of the wellbore fluids to maintain the set. Additional setting force can be attained by applying additional pressure by selective means or by applying pressure to the entire casing string if applicable. The "MPas" Packer is normally run in the liner string between screens, slotted liners, or gravel packed sections as a means to isolate production intervals. It can also be used in annular cementing operations to isolate the open hole / liner annulus in openhole completions in conjunction with Stage Cementing Equipment. The "MPas" Packer can be run as a single or stacked in multiples to
provide for increased seal length.

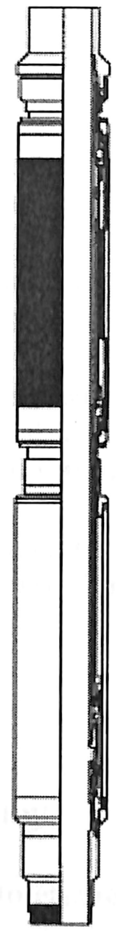


Fig. 7.1 Mechanical External Casing Packer

Features And Benefits

The "MPas" Packer can be used as a cementing packer and for zone is isolation in completions having no cement. The "MPas" ECP performs the following functions:

- Provides Zone Isolation – Seals wellbore between zones either as backup for the cement or as the seal.
- Protects Cement – channeling damage is prevented by blocking movement of gas or fluid and cement is allowed to set undisturbed.
- Protect Sensitive Formations - Sensitive formations are isolated from cement and protected from damage.
- Allows Cementing Deep Well Without Damaging Lower Zones - Deep wells can be stage cemented to protect the lower zones from the high differential pressure of a long column of cement.

- ➢ Provides Proper Cement Distribution - The "MPas" ECP helps to centralize the casing in the hole to ensure even cement distribution around casing.

- ➢ Compensates For Borehole Movement - The "MPas" Packer compensates for wellbore movement around the seal area to hydrostatic pressure providing additional set to the element eliminating the need for intervention.

- ➢ Setting Force Locked Into The Element - A body lock ring ensures that the element stores the setting force applied to the element.

- ➢ Protection Against Premature Element Setting - Locking Dogs protect against premature element setting if a seal failure should occur unless the Setting Sleeve is physically shifted to the proper position.

- ➢ Progressive Setting of "MPas" Element - A progressive setting sleeve inside the element allows for a progressive set of the element to fully set and conform to the wellbore.

Operation:

Pre-job Preparation and Planning:

1. Visually check the "MPas" Packer to ensure that the Packer Element Assembly is undamaged.

2. The (4) set screws should already have been removed from the Bottom Connector Sleeve adjacent to the Body Lock Ring Housing. Refer to Dimensional Data Drawing 480-010 magnified section to determine if setscrews are present. Check Dimensional Data Drawing 480-010 to ensure the Balance Sleeve is shouldered up against Bottom Sub by comparing to the "M" dimension referenced in the drawing.

3. All remaining set screws should be confirmed in place and locked tight.

4. Confirm that the proper Shifting Tool is to be used with "MPAS" Packer and all connections are torqued up with setscrews in place.

On Location:

1. Conduct an additional check to ensure no damage prior to picking up the "MPas" Assembly (Items 1-4 on Pre-job).

2. Confirm that the work string tally to be used allows for the shifting tool to be positioned below the "MPas" Packer.

3. Make up the “MPas” Packer Assembly into the liner string. Do not tong between the Top and Bottom Sub to avoid damaging the Packer Element or Setting Mechanism.

4. Run the assembly to TD with the liner. The maximum Run In Hole (RIH) speed with the “MPas” Packer in liner string is 1 minute / stand in cased hole and 2 minutes / stand in open hole.

5. The Balance Sleeve is sheared & shift open by Pulling Out Of Hole (POOH) with the shifting collet through the “MPas” Packer.

6. If a Multiple Acting Indicating Collet (MAIC) is to be used as the Shifting Collet in a single trip application, consideration should be given to implementation of an emergency release above the MAIC as a contingency for pulling POOH without setting the “MPas” Packer.

7. If the “MPas” Packer is to be set in a 2 trip application the Shifting Tool needs only to reach below the Balance Sleeve and then POOH to shift sleeve & set packer.

8. Additional pressure can be applied to increase the setting force to the packer element by straddling the “MPas” Packer or by pressuring up the casing string if applicable (Downhole Hydrostatic Pressure + Applied Pressure < 6000 PSI).

If the “MPas” Packer is to be subject to a down hole hydrostatic pressure above 6000 PSI, contact Open Hole Completions-Inflate Engineering

The packer can be set by one of the two methods:

1. Inner work string with setting collet can be used to shift a sleeve in the packer and activate the setting mechanism as the work string is pulled out of the hole; or

2. Packer can be actuated by differential pressure.

A lock mechanism maintains the setting force even if hydrostatic pressure is removed. Additional setting force can be applied at any time by increasing the hydrostatic or applied pressure at the packer. Since hydrostatic pressure actuates the MPas, it is able to adjust to the wellbore throughout the life of the well. One trip deployment and instant sealing allow for immediate testing following activation. The seal element is effective in both water based and oil based fluids. The packers can be run on blank casing or with stand alone screens to separate producing zones, or between screens in a gravel pack for zone isolation. In horizontal gravel packs, the packers can be run and set in a single trip when used with Beta Breaker valves. The valves prevent sand from being deposited around the packer OD before it is set. In uniform flow completions, MPas packers can provide compartmentalization between inflow control devices to mitigate coning along the horizontal well. In an extensive field study, the MPas, when run in conjunction with an EQUALIZER system, increased an operator's overall economic recovery by up to 60% as compared to existing completions. The operator reported that MPas/EQUALIZER solution "improved depletion, prolonged well life, delayed gas and water production, maximized sweep, eliminated future well intervention, controlled sand, and substantially reduced gas cusping and water coning"

Table 7.1 Specification

Specification	Units	Packer Size (in.) 5-1/2"
Liner Weight	lbs/ft	17
Maximum Outside Diameter	in.	8.000
Minimum Inside Diameter	in.	4.819
Make-up Length (Approx. Depending on Thread)	in.	130.97
Thread Up	-	As Required
Thread Down	-	As Required
Minimum Flow Area	in^2	18.24
Temperature Rating(1)	°F	285
Element Assembly Elastomeric Material	-	Nitrile
Minimum Tensile Strength(2)		
• 80 ksi Material	lbs	261341
• 110 ksi Material	lbs	359344
Burst Pressure Rating(2)		
• 80 ksi Material	psi	5761
• 110 ksi Material	psi	7921
Collapse Pressure Rating(2)		
• 80 ksi Material	psi	5222
• 110 ksi Material	psi	6258

(1) Temperature rating listed is with standard elastomeric material. Higher rating may be possible with additional qualification or material change. Consult product engineering for higher temperature applications.

(2) Mechanical strengths listed are 80% of actual calculated minimum failure values using minimum material conditions and material strengths.

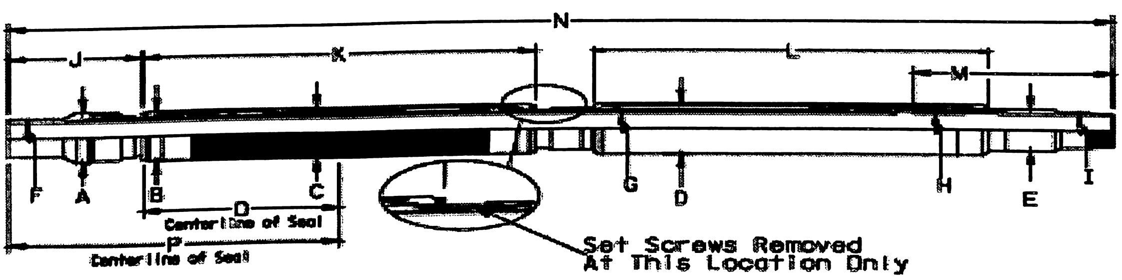


Fig. 7.2 "MPas" External Casing Packer Dimensional Data Drawing

Dimensional Data Refer to Drawing No. 480-010

Description	Dim	Packer Size (in.)
		5-1/2
Liner Weight (lbs/ft)	-	17.00
Top Sub Major OD (in.)	A	8.000
Element Assembly Major OD (in.)	B	7.754
Packer Element OD (in.)	C	7.813
Hydrostatic Setting Mechanism Housing OD (in.)	D	8.000
Bottom Sub Major OD (in.)	E	8.500
Top Sub ID (in.)	F	4.892
Packer Mandrel Minimum API Casing ID if Size & Wt. Csg. (in.)	G	4.819
Balance Sleeve ID (in.)	H	4.938
Bottom Sub ID (in.)	I	4.892
Top of "Mpas" Packer Top Sub to Element Assembly (in.)	J	16.625
Element Assembly Overall Length (in.)	K	48.312
Hydrostatic Setting Mechanism Housing Overall Length (in.)	L	48.432
Bottom of Packer to Top of (6.25") Balance Sleeve Length (in.)	M	24.229
"MPas" Packer Overall Length (in.)	N	135.236
Top of Packer to Center of Element Assembly Length (in.)	O	40.781
	P	24.156

Table 7.2 Dimensional Data

REACTIVE ELEMENT PACKER

The wellbore isolation systems use Reactive Element technology to offer customizable wellbore isolation solutions for applications ranging from water shutoff and inflow control to intelligent wells, or multi-zone fracturing, and acid stimulation. The RE Reactive Element Packer uses elastomeric polymer sealing elements that react with oil or water to swell and isolate zones in either open or cased hole, without the need for cement, special trips, running tools or specialized rig site personnel. REPackers are run in the well and begin to swell when they come into contact with oil or water. As the packers swell, they seal off the annulus between the liner/casing and the open hole to provide isolation between zones with different pressures or to simply shut off flow in the annulus and prevent fines migration along the wellbore. The REPacker is manufactured by bonding and wrapping a rubber element onto a joint of casing. A wide array of options in element length and diameter are available. Additionally, the casing joint can match the mechanical properties of the proposed liner string.

As a result, installing the REPacker within the string can be as simple as torquing another joint of pipe.

Top 10 Reasons to Choose the REPacker

1. Non-reversible elastomers won't shrink if fluids are changed after swelling.
2. Fastest delivery time in the industry– as little as four weeks.
3. Reduces HS&E risks.
4. Reduces operational risk.
5. REBarrier and REFlex field-installable options save time and cost.
6. Lowers rig personnel requirements.
7. No running tools reduces complexity and cost.
8. Tested to 10,000 psi.
9. Versatile and customizable.
10. Eliminates near-wellbore damage associated with cementing.

REPacker Water-Reactive Elements

Incorporate water-absorbing particles into a field-proven nitrile-based polymer. These particles swell by absorbing water to expand the rubber.
Without being physically absorbed into the rubber matrix, so there is no risk
Of adversely affecting the element's sealing properties

REPacker Oil-Reactive Elements

Uses oleophilic polymers that absorb hydrocarbons into the matrix to swell and lubricate the element as it expands.

Comparison of Open Hole Packers
Table 9.1

	Mpas	ECP	Reactive Element	Reactive core
Parameters				
Inflation Procedure	Mechanical/Hydraulic (extruding packer)	Cement Inflated	Reaction with well bore fluid	Inflation+ Swell
Number of trips	Single	Two-trip	Intervention less	Single
Running Tool	Yes*	Yes	No	Yes*
Integrity	Good	Good	Medium	Good
Differential Hold up	Good	Good	Size Dependent(Length+OD)	Size Dependent(Length+OD)
Application	Sandstone/Carbonate	Sandstone/Carbonate	Sandstone	Sandstone/Carbonate
ID	reduced packer ID	Large ID	Full tubing ID	Large ID
Cost (0-10 scale)	MostExpensive	Less expensive than Mpas	Least Expensive	Affordable.
* Not required if the tool is hydraulic set and the completion is a closed system				

Cost comparative study of an ECP completion with a normal cemented completion

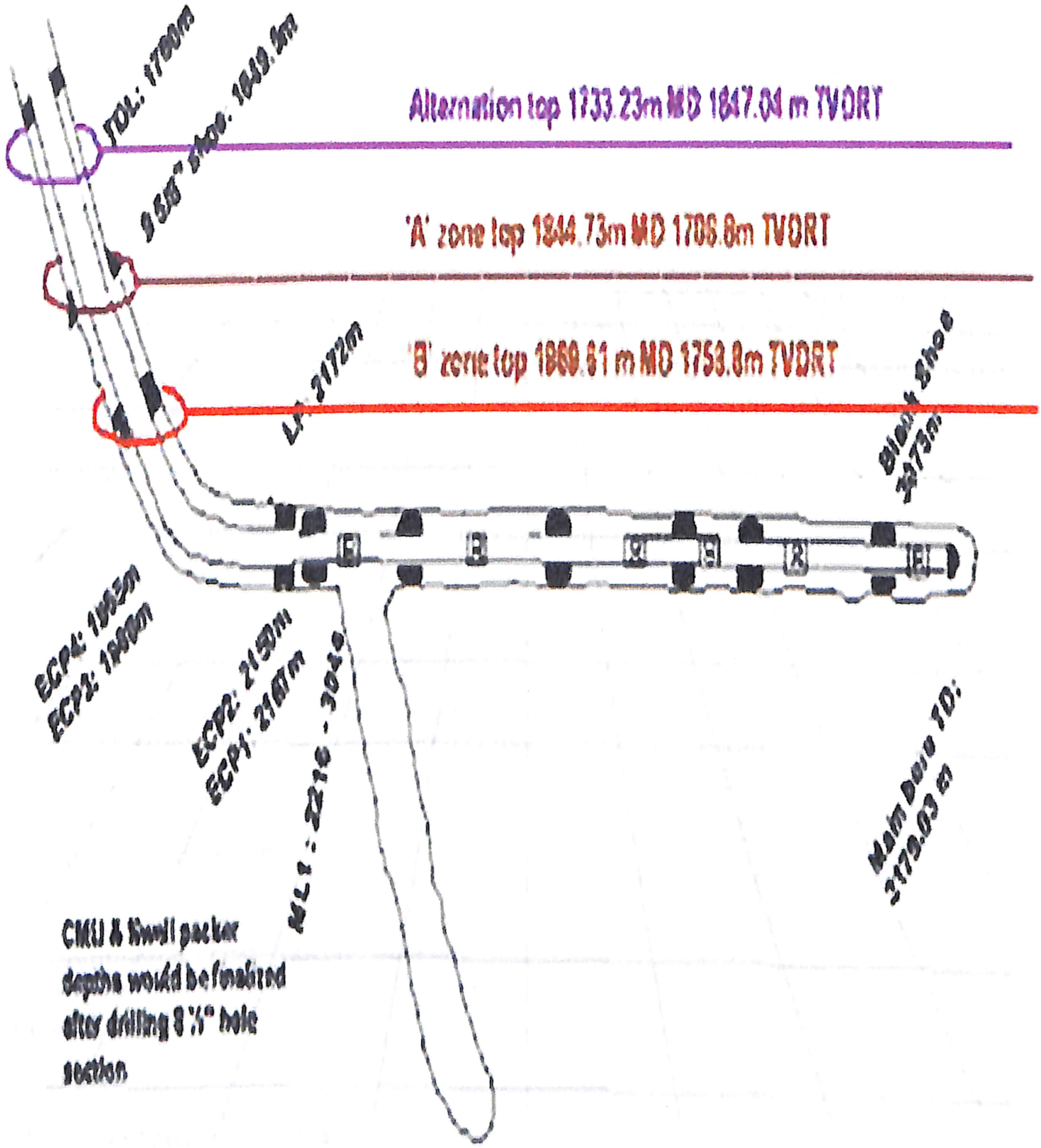


Fig. 10.1 Completion scheme of a horizontal well

The following cost analysis is for above horizontal well that has two hydro carbon bearing horizons: zone A (Gas Bearing) & zone B (Oil Bearing)the operators problem is to have zonal isolation, so as to keep the gas of zone A into the reservoir in order to conserve reservoir energy and enhance ultimate primary recovery. The reservoir is under Gas Cap Driving Mechanism. The operator has a choice of going for two types of completions procedures:

1) With normal cemented liners (7" & 4.5"), or

2) A liner system with ECP's.

1) Normal cemented liners:

In this type of completion the operator had to drill 8 ½" well bore from the 9 *5/8*" casing shoe and liner complete it till the zone A. 7" liner was run and hanged from the liner hanger. The liner was cemented throughout its length i.e. 200 m (laterally). From the 7" liner another 800 m (laterally) was drilled in the zone B using 6" drill bit. This zone was completed with an open whole 4 ½" liner having sliding sleeves and swell packers as the lower completion for segmentation. Cost consideration: Drilling rate: 200 m/ day Jack up rig cost: 300,000 USD/ day

Operations	**Time**	**Cost (KUSD)**
Drill 8 1/2" hole zone A (200 m)	1 day	300
Trip out	2 hours	25
7" liner hanger cost		70
Running 7" liner in hole	1/2 day	150
Cementing the liner	1/2 day	150
Waiting for cementation	1 day	300
CBL-VDL logging	1 day	300
Drill 6" hole zone B (800m)	4 days	1200
Trip out	10 hours	125
4 1/2" liner hanger cost		70
Lower completion cost (swell packers, sliding sleeves)		200
Total cost		**2,890**

2). Liner system with ECP's

In this type of completion the operator drilled 8 ½" hole throughout from the 9 5/8" casing shoe to 1000m. Zone A was completed by a 7" liner having 4 ECP's to isolate gas from this zone. Zone B was open hole completed with a 5 ½" liner (connected to the 7" liner by a cross over) having the same lower completion jewellery as in the first case. Fig: 21 Cost analysis: Drilling rate: 200 m/ day Jack up rig cost: 300,000 USD/ day

Operations	Time	Cost (KUSD)
Drill 8 1/2" hole	5 days	1500
Trip out	10 hours	125
7" liner hanger cost		70
Running 7" liner in hole	1/2 day	150
Cost of ECP's (4 in Number)		200
Cost of running tool		50
Inflating ECP's	8 hours	100
Lower completion cost (swell packers, sliding sleeves)		200
Total cost		**2,395**

Added advantages:

Apart from being cost effective, this type of completion also gives the following added advantage:

- Greater reservoir contact
- No squeeze cementing job is required (generally in highly deviated wells 2-3 squeeze jobs are required)
- Higher bottom hole diameter
- Auto gas lift system can be installed
- Greater tubing size (less friction)
- Less rig time requirement

Conclusion:

In the light of all the above advantages, the second type of completion scheme is more lucrative to the operator since it is not only cost effective but also save a lot of rig time (in offshore wells rig time is crucial). Also this type of completion is more reliable

CASE STUDY

BG Panna India RCPacker Qualification Testing.

The following is a summary of Engineering, development and qualification testing for BG India.

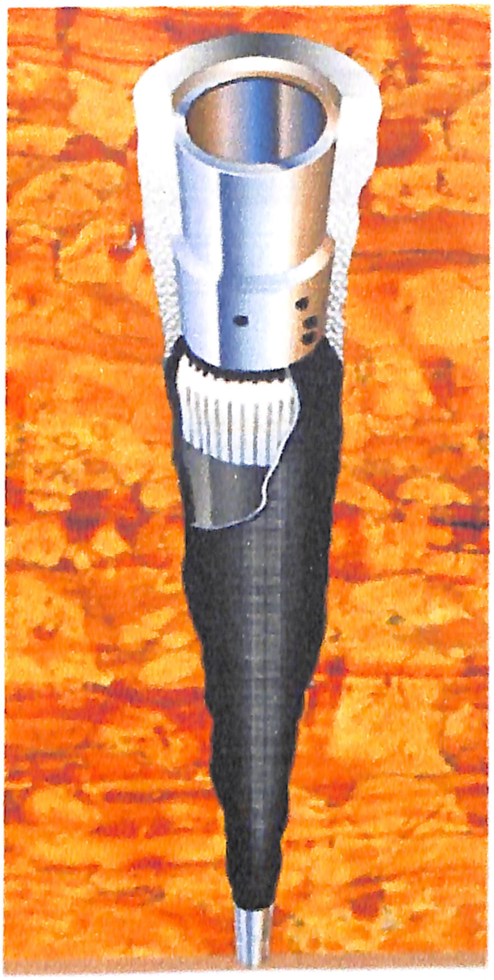


Fig. 11.1 RCPacker

Design Features

•Include All Design Features of XTremeZone Packer
•Safe Inflation Media
•ECP Element Inert in Wellbore fluid
•Immediate Isolation
•Swelling Layer Protected by Element
•Applications in Oil, Gas or Water Injection Wells
•Inflation Medium Combines with Inner layer of ECP to form an elastomeric like core
•Negligible bulk volume loss during transition from liquid to solid elastomeric core
•5-1/2" by 8" RCPacker in 8-1/2" hole
•5-3/4" by 8" RCPacker with Feed-thru capabilities

.5-3/4" Reactive Core Formation Packer With Control Lines

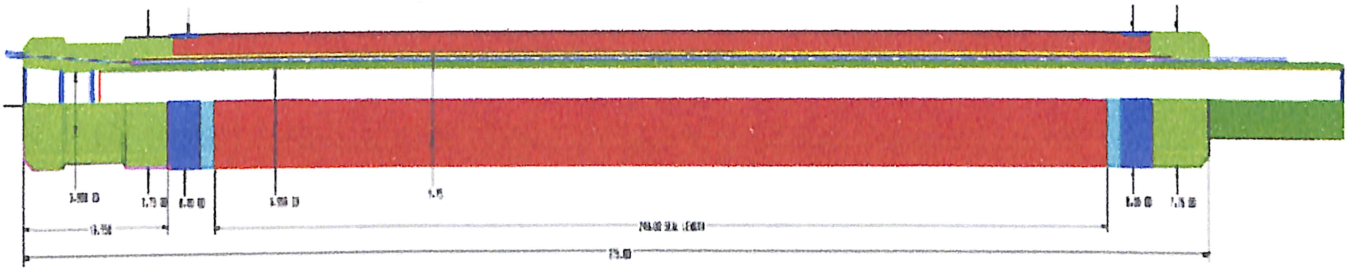


Fig. 11.2

Test Procedures:

- Place Strain Gages on Test fixture with 8.9" ID.
- Calibrate Strain Gages in equivalent PSI.
- Install RCPacker in fixture.
- Inflate RCPacker in Fixture and record Strain Gag pressure.
- At 9 Days @ 180° F Apply 3000 PSI Differential.
- At 13 Days @ 180°F Apply 3000 PSI Differential.
- At 29 Days increase temp 250°F Apply 3000 PSI Differential.
- At 40 Days cool to 70°F Apply 3000 PSI Differential.
- At 43 Days increase temp to 290°F Apply 3000 PSI.
- Mill Window in Fixture and Inspect Element.

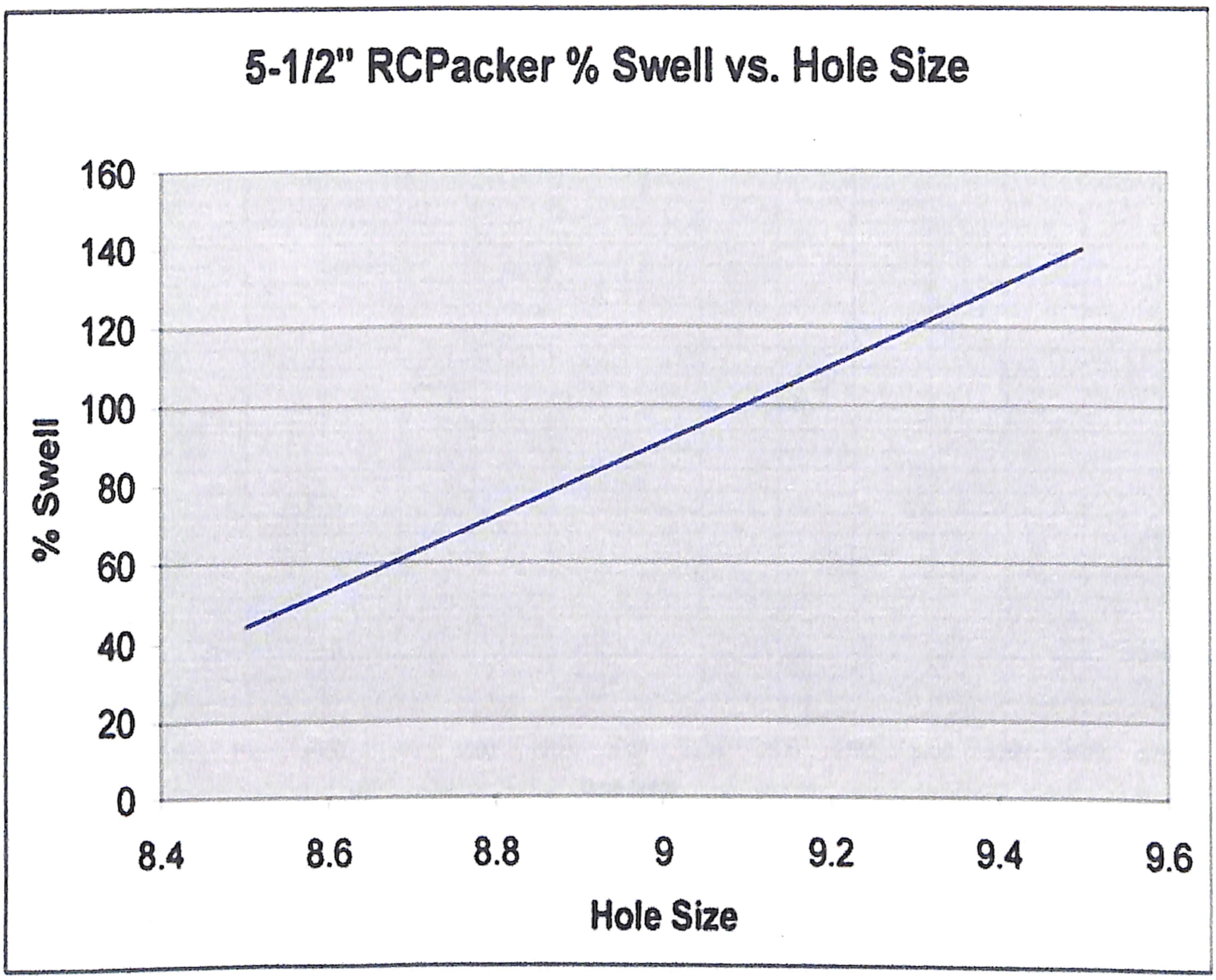


Fig. 11.3 5-1/2" RCPacker % Swell vs. Hole Size

Differential Pressure test # 1

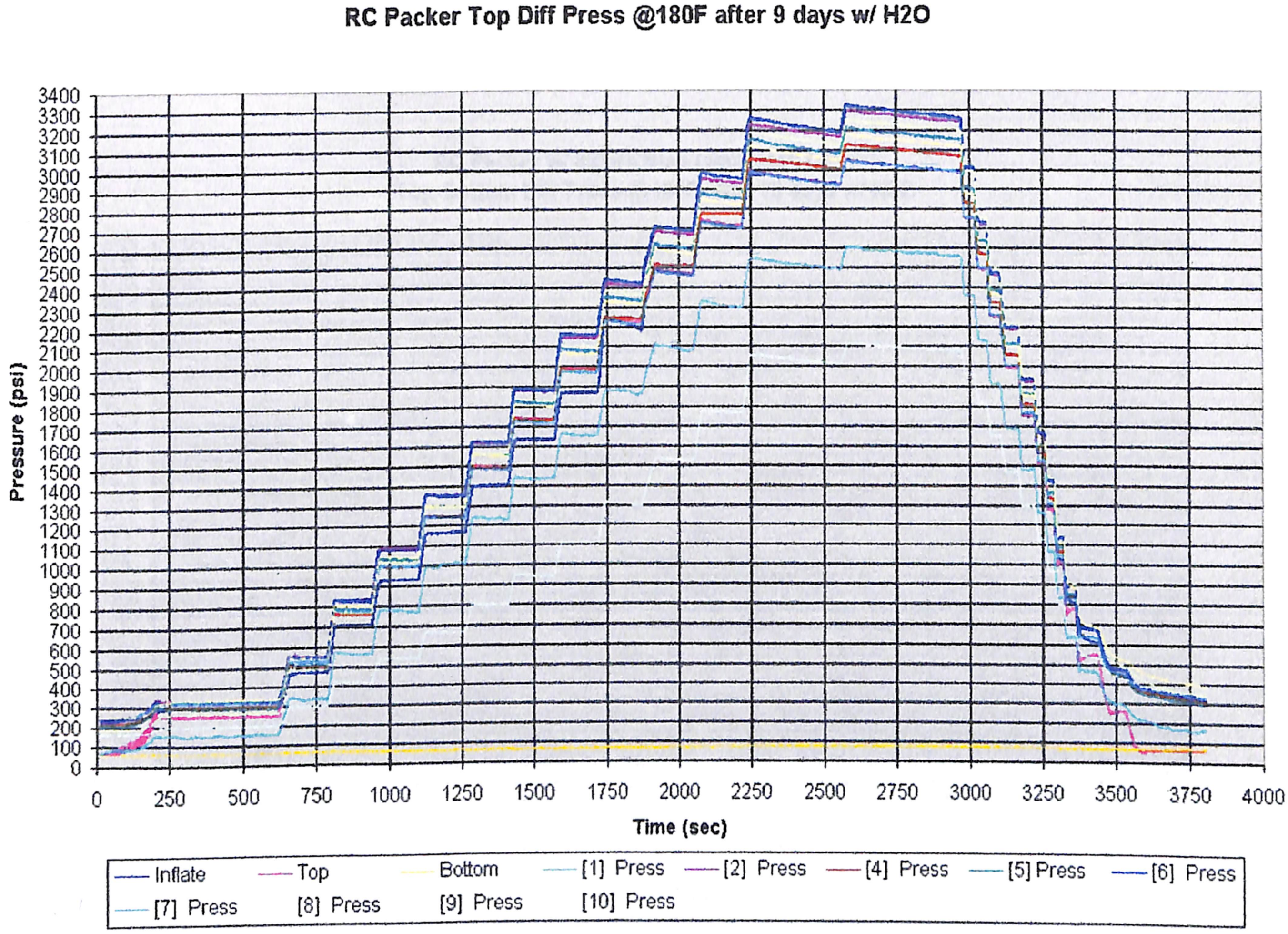


Fig. 11.4 Differential Pressure test # 1

After 9 days Strain Gage data indicates that the Reactive Core has gained sufficient strength to support a pressure gradient from top to bottom.
Note: Liquid filled ECPs maintain inflation pressure plus boost pressure from applied Differential along the entire element (No Gradient).

Differential Pressure test # 2

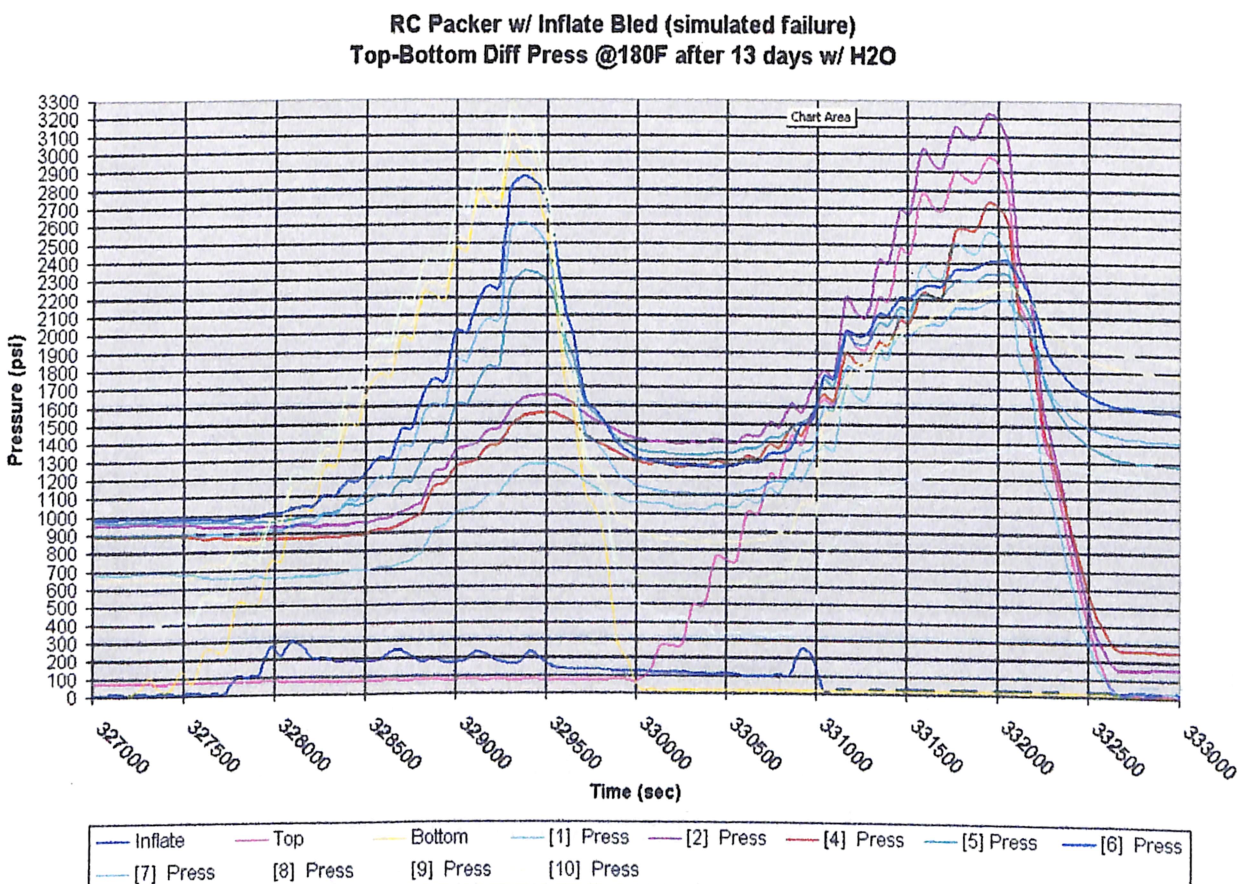


Fig. 11.5 Differential Pressure test # 2

After 13 days strain gage data clearly indicates a pressure gradient along the packer element when pressure is applied from top or bottom. This response is indicative of a fully elastomer packer element. A valve communicating under the element is opened to simulate a breach in the element with no resulting pressure loss.

Differential Pressure test # 3

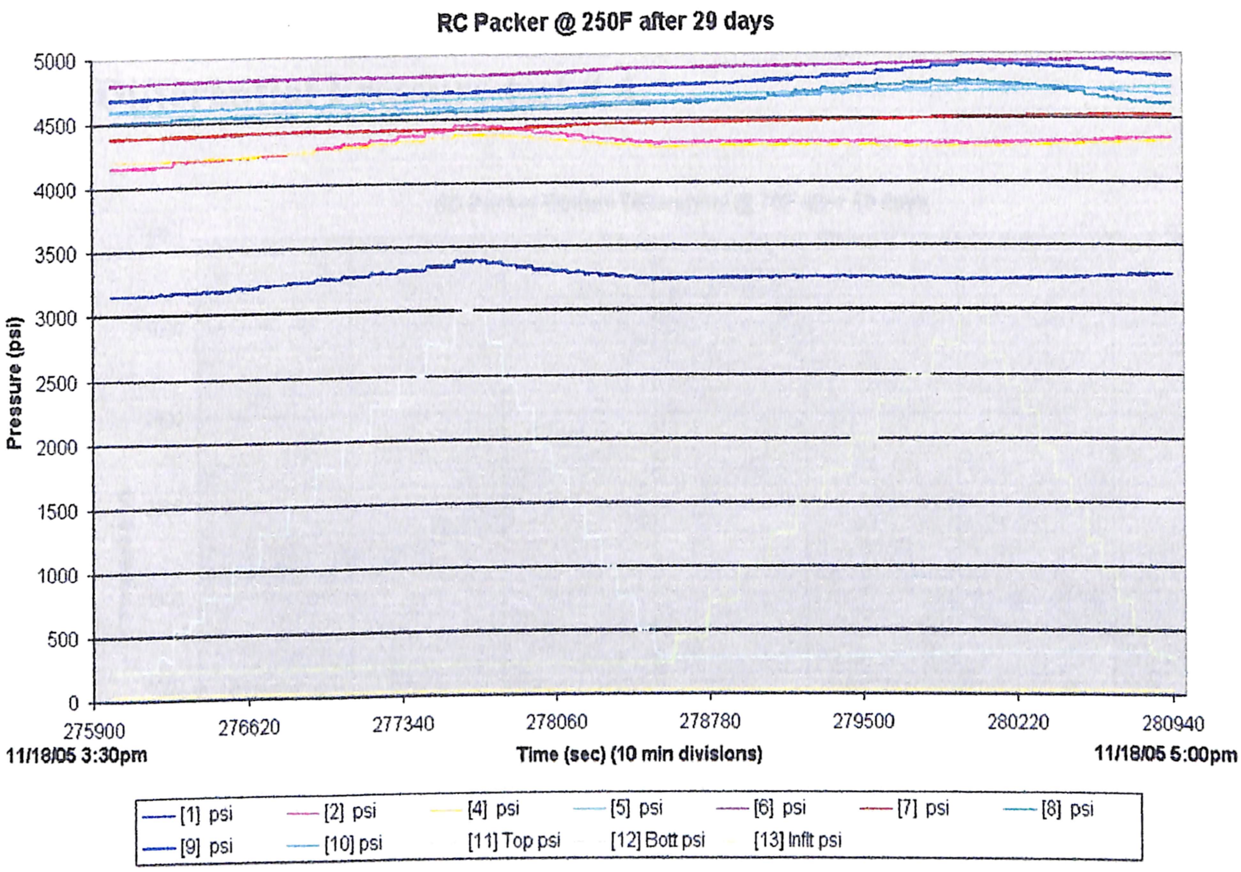


Fig. 11.6 Differential Pressure test # 3

Temperature in the packer is increased to 250°F. Strain gage data measures increased pressure (Seal Load) resulting from thermal expansion of the element and reactive core. Since the applied differential pressure is less than seal load the strain gages along the packer do not change as differential pressure is applied from either end.

Differential Pressure test # 4

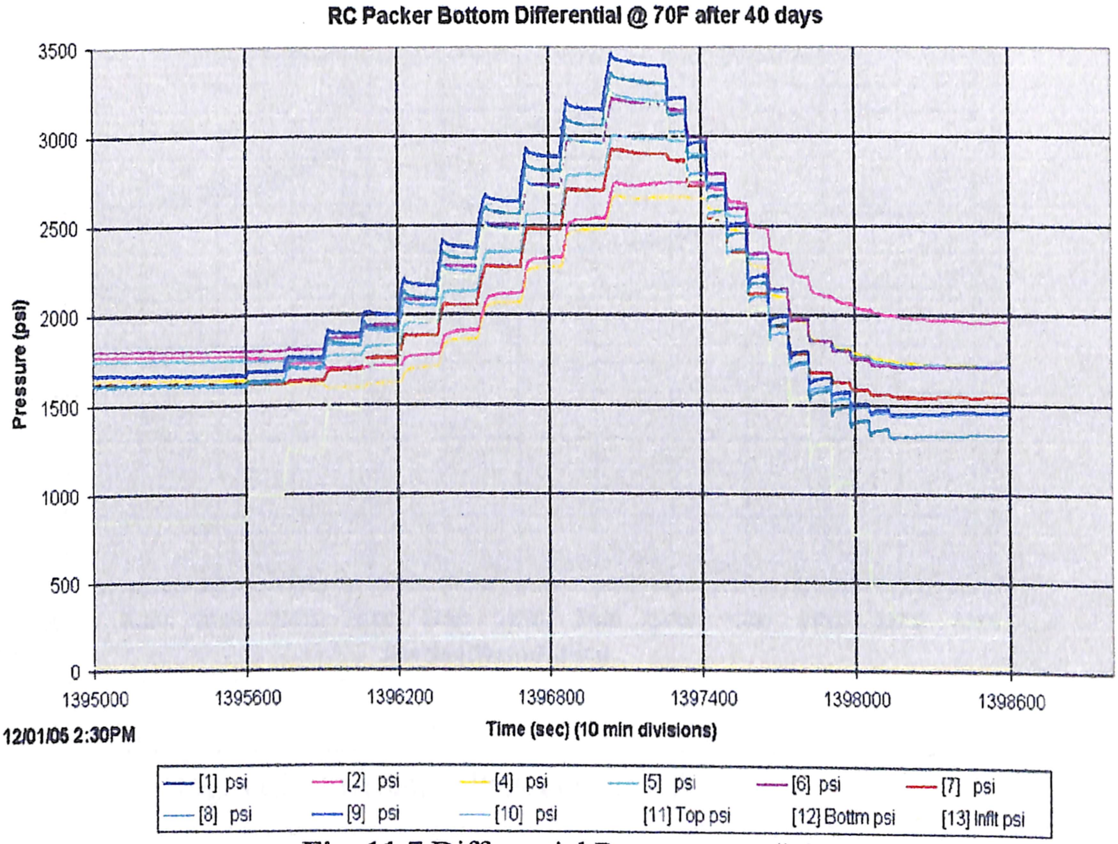


Fig. 11.7 Differential Pressure test # 4

RCPacker is cooled to 70°F to simulate injection well cooling. Thermal contraction of the element decreases seal load but the element successfully seals 3000 PSI differential pressure

Differential Pressure test # 5

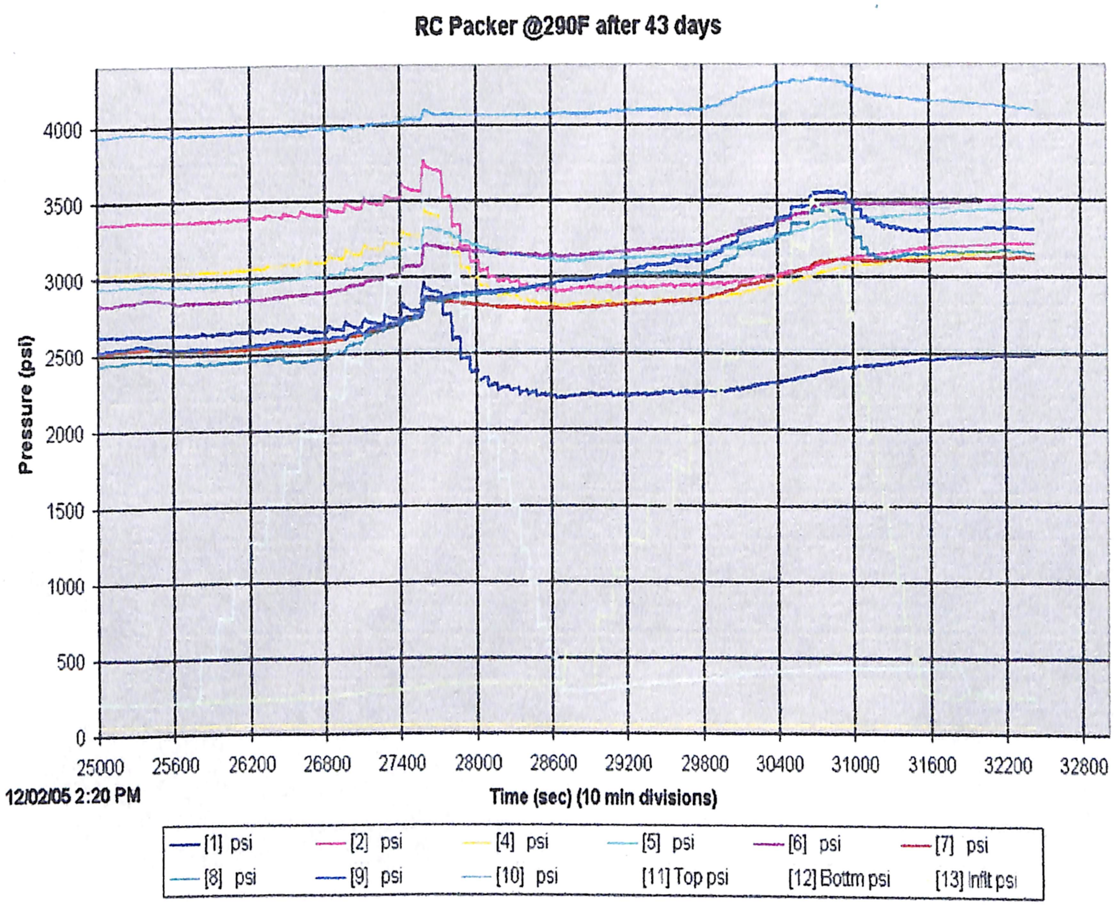


Fig. 11.8 Differential Pressure test # 5

Temperature is increased to 290°F and strain gages once again indicate an increase in seal load. The packer once again successfully seals 3000 PSI Differential.

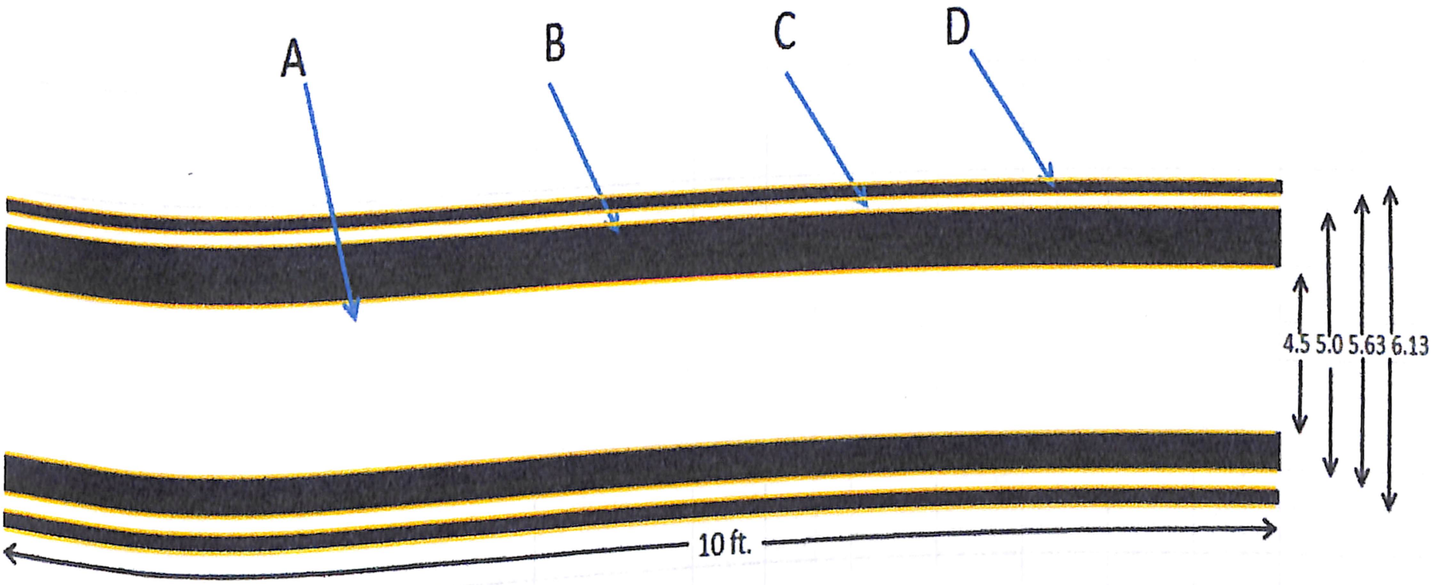
Fig. 11.9 RCPacker Milled Window

BG India Test Conclusions

The RCPacker successfully held 3000 Psi Differential Pressure Under all conditions expected in the BG India Panna Project
– Water Injection 70°F
– Circulating Temp 180°F, & 250°F
– Undisturbed Temp 290°F

The designed RC Packer Element which can be used in a hole size varying from 6.5 in to 7 in.

R C PACKER ELEMENT



Dim	Part Name	Outer Dia. (inches)
A	Base Pipe	4.5
B	Inner Core Element	5
C	Steel Ribs	5.63
D	Outer Nitrile Element	6.13

Fig. 12.1 The designed RC Packer Element

Swell Predictor Test.

RCPacker Pre-job Information Sheet

The purpose of this data sheet is to provide as much pertinent information about the well in question as possible so that the optimal packer can be designed for the application. Each parameter below plays a key role in the packer dimensions, characteristics and limitations for operations. Although, some unique jobs may require a fluid sample to be tested prior to the job usually a complete data sheet can eliminate that need

Well Information

Application Objective (Barrier, Zonal Isolation, etc…)	
Well Type (Oil, Gas, Water Injector, Condensate)	**Oil well**
Wellbore Fluid Viscosity	22 cp
Wellbore Fluid Density	10.6 ppg
Production Fluid Viscosity	0.4 cp
Production Fluid Density	5.8 ppg
Total Well MD / TVD	3500 ft
Maximum Deviation	90 deg
Maximum Dog-Leg Severity	5 deg
Minimum Run-in Drift	6.5 in
Time to Reach Setting Depth	
Open Hole / Cased Hole	Open hole

Setting Depth (MD/TVD)	3500 ft
Setting Hole ID	6.5 in
Bottom hole Temperature (Static)	250 deg F
Bottom hole Temperature (Producing)	220 deg F
Bottom hole Pressure (Static)	1800 psi
Bottom hole Pressure (Flowing)	1400 psi
Gauge Hole (Y/N)	y
Additional Comments (Wellbore Stability, Mineral Composition, etc...)	Salinity=0.7%, %Swell 363.16%, Time to seal=4.76d

Desired Results

Pressure Differential (PSI)	**631.28 psi.**
Swell Rate (days)	**3.76 days**

Based on the completed information above an REPacker design will be made to optimize the operation. There are currently 2 types of swellable materials that are being used today; Oil-swelling and water-swelling elastomer. In addition, 3 different styles of REPacker; Standard (mandrel wrapped), Slide-on (field installable) and Stretch-on (field installable). It is generally suggested to include a hole survey with this data sheet to better analyze the geometry of the wellbore

The predictor result:

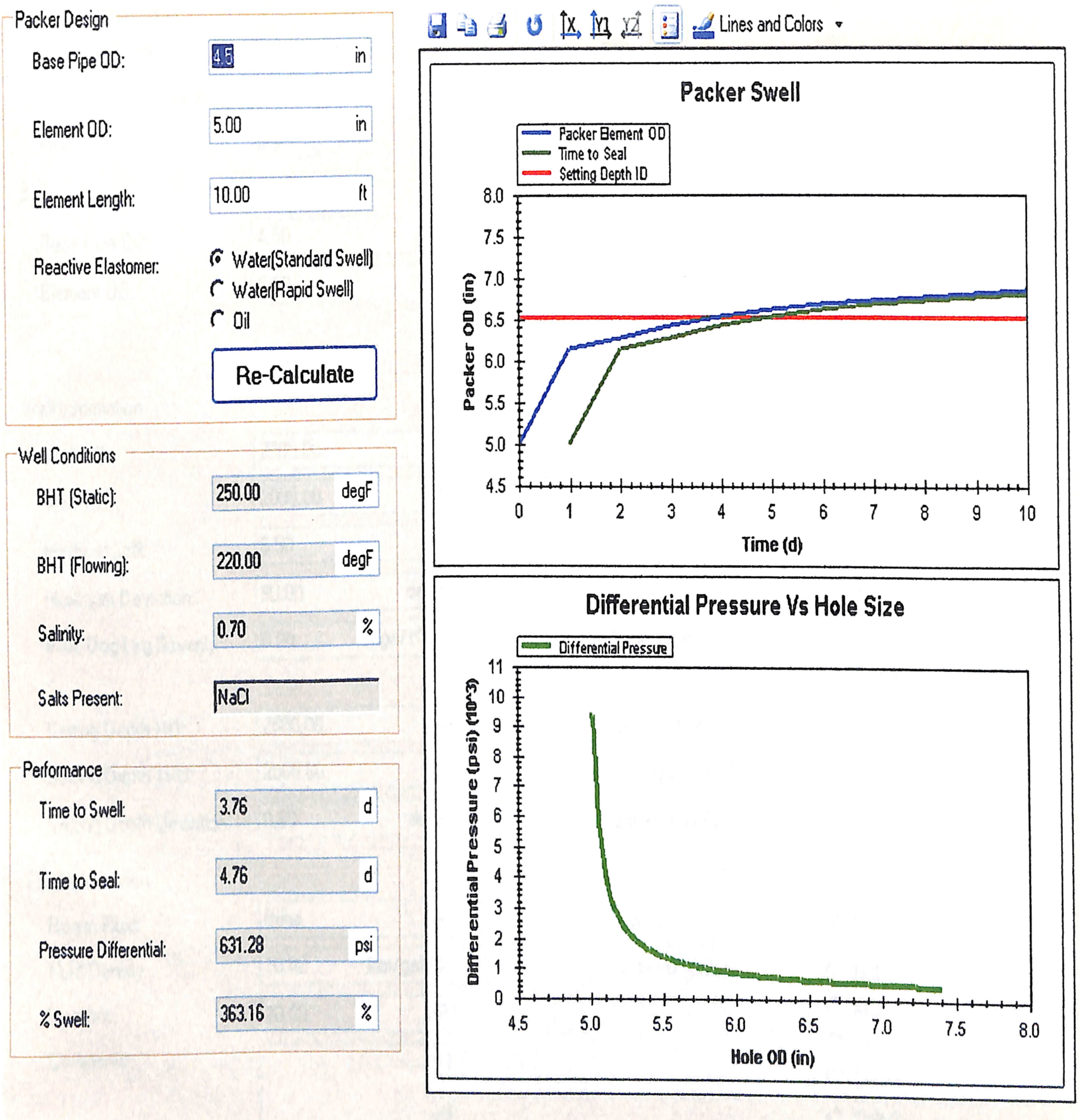


Fig. 12.2

Swell Test For a fluid having density=10.00 lbm/galUS & Visosity=20cp at MD=2500 Ft, TVD=2000Ft.

BHP(Static)=2000 degF,BHP(Flowing)=1800 deg F

Customer Information

Customer Name:	hggf	Rig:	ighg
Geographical Location:		Well Name/Number:	ihhg
Field:	ghy	Date:	7/28/2009

Packer Design

Base Pipe OD:	4.50 in	Element Length:	10.00 ft
Element OD:	5.00 in	Reactive Elastomer:	○ Water(Standard Swell) ◉ Water(Rapid Swell) ○ Oil

Well Information

Well MD:	2500.00 ft	BHP (Static):	2000.00 psi
Well TVD:	2000.00 ft	BHP (Flowing):	1800.00 psi
Minimum Drift:	6.50 in	BHT (Static):	220.00 degF
Maximum Deviation:	90.00 dega	BHT (Flowing):	200.00 degF
Max. Dog-Leg Severity:	5.00 dega/100ft	Application:	◉ Open Hole ○ Cased
Setting Depth MD:	2500.00 ft	Gauged Hole:	☑
Setting Depth TVD:	2000.00 ft	Setting Depth ID:	6.50 in
Setting Depth Deviation:	0.00 dega	Est. Run-in Time:	0.00 h

Fluid Information

Run-in Fluid:	Brine	Salinity:	0.70 %
Fluid Density:	10.00 lbm/galUS	Salts Present:	◉ NaCl ○ KCl ○ CaCl2 ○ ZnBr2 ○ CaBr2
Viscosity:	20.00 cP		
Comments:			

Fig 12.3

Under the above conditions the packer can hold a diffrential of 686.76 psi and swell in 4.85 days

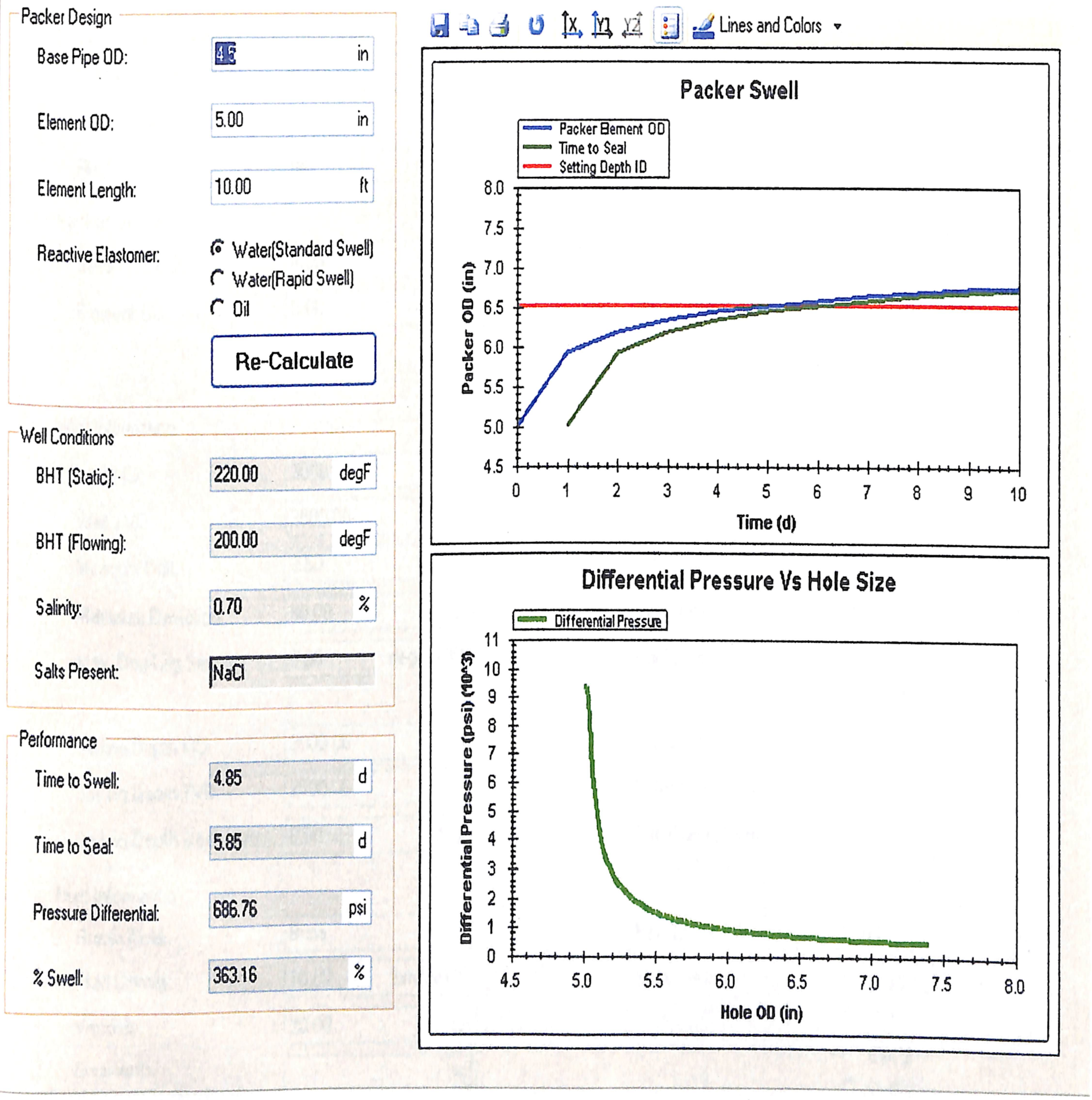
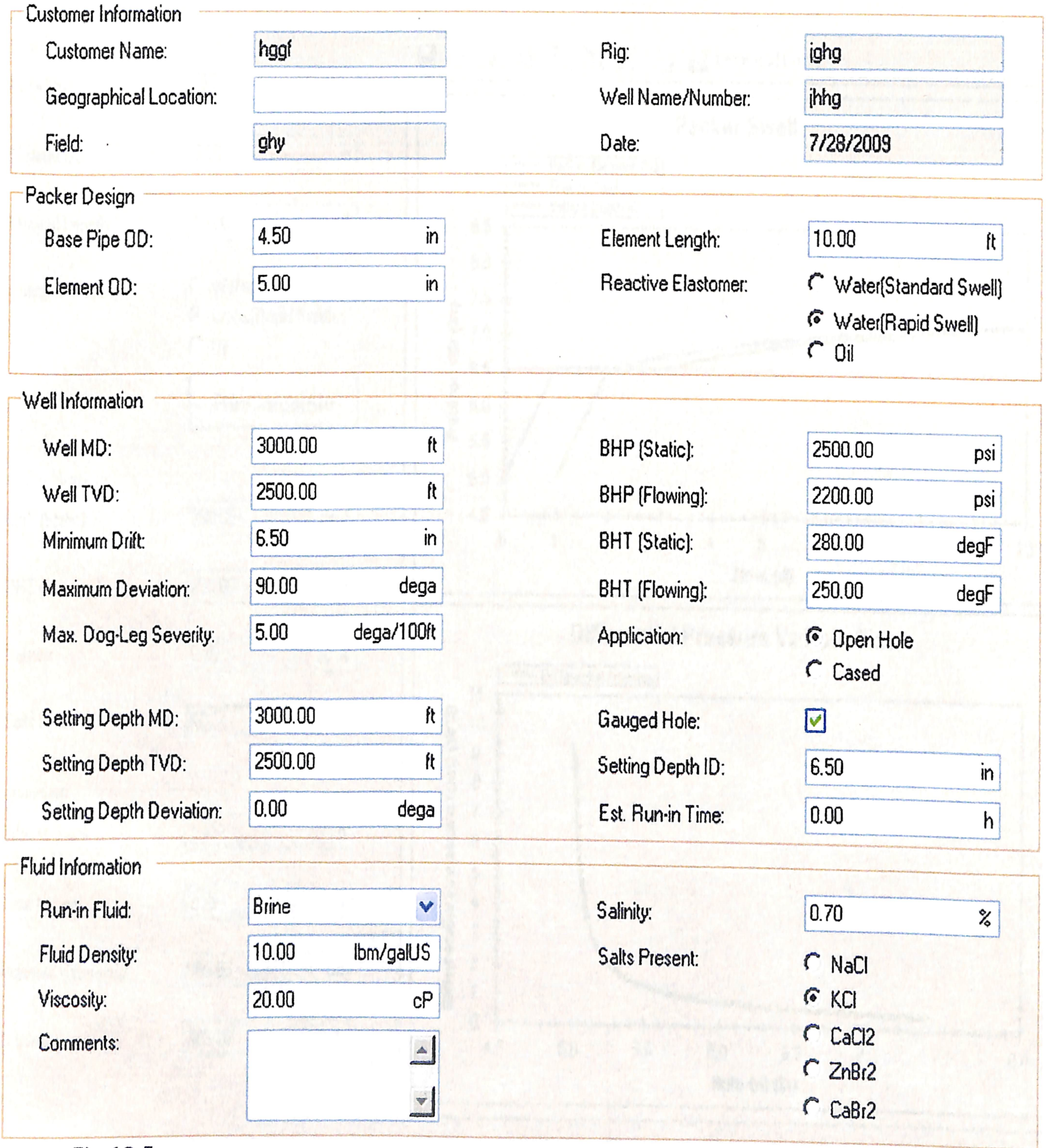


Fig.12.4

If the Salt is KCL:



Customer Information

Customer Name:	hggf	Rig:	ighg
Geographical Location:		Well Name/Number:	ihhg
Field:	ghy	Date:	7/28/2009

Packer Design

Base Pipe OD:	4.50 in	Element Length:	10.00 ft
Element OD:	5.00 in	Reactive Elastomer:	◯ Water(Standard Swell) ◉ Water(Rapid Swell) ◯ Oil

Well Information

Well MD:	3000.00 ft	BHP (Static):	2500.00 psi
Well TVD:	2500.00 ft	BHP (Flowing):	2200.00 psi
Minimum Drift:	6.50 in	BHT (Static):	280.00 degF
Maximum Deviation:	90.00 dega	BHT (Flowing):	250.00 degF
Max. Dog-Leg Severity:	5.00 dega/100ft	Application:	◉ Open Hole ◯ Cased
Setting Depth MD:	3000.00 ft	Gauged Hole:	☑
Setting Depth TVD:	2500.00 ft	Setting Depth ID:	6.50 in
Setting Depth Deviation:	0.00 dega	Est. Run-in Time:	0.00 h

Fluid Information

Run-in Fluid:	Brine	Salinity:	0.70 %
Fluid Density:	10.00 lbm/galUS	Salts Present:	◯ NaCl ◉ KCl ◯ CaCl2 ◯ ZnBr2 ◯ CaBr2
Viscosity:	20.00 cP		
Comments:			

Fig.12.5

The result with KCL present:

The element will take 1.15 days to swell with diffrential hold up of 585.85 psi.

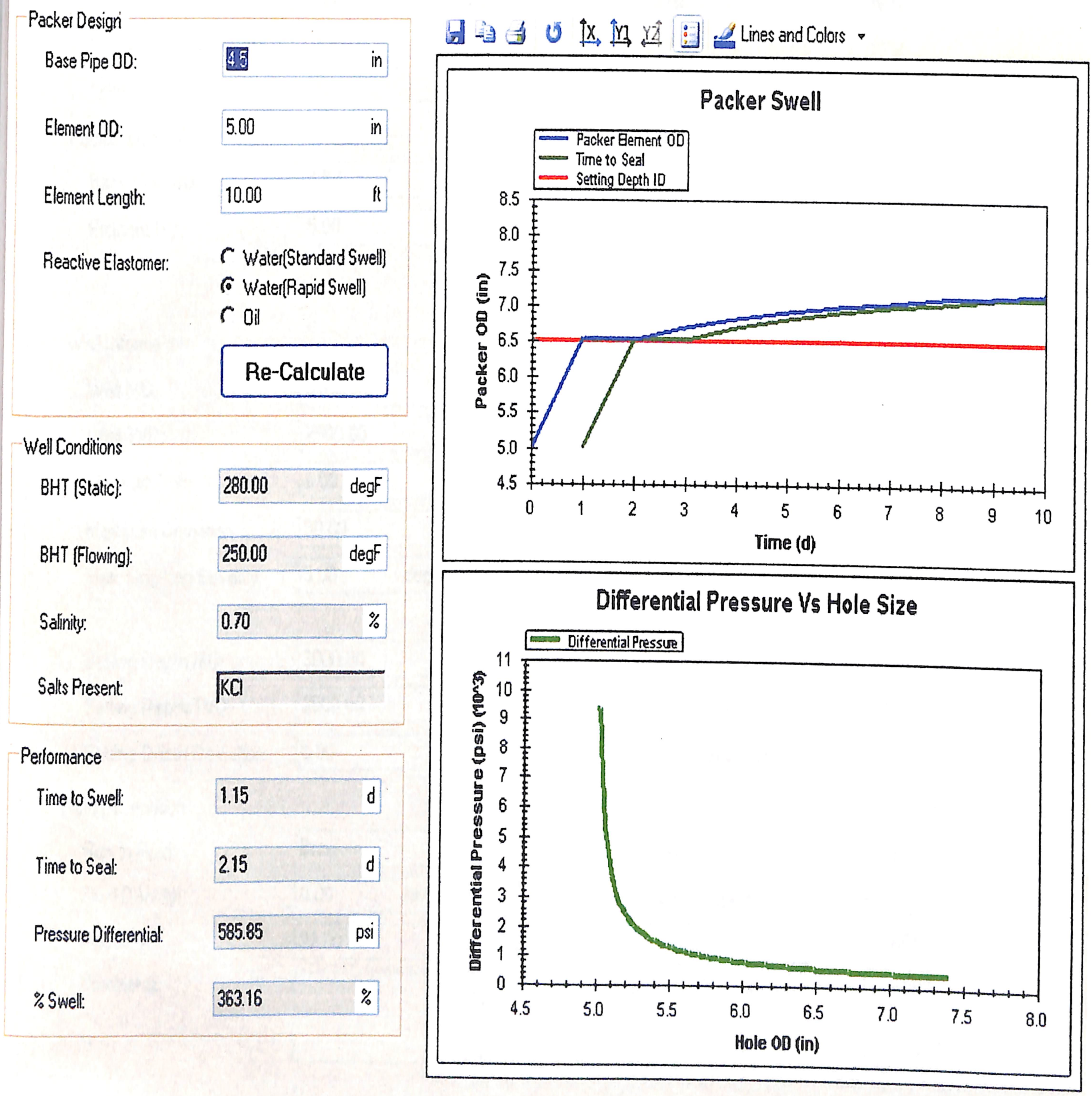


Fig.12.6

If the fluid Viscosity is changed to 22 cp and density=8.0 lbm/galUS.

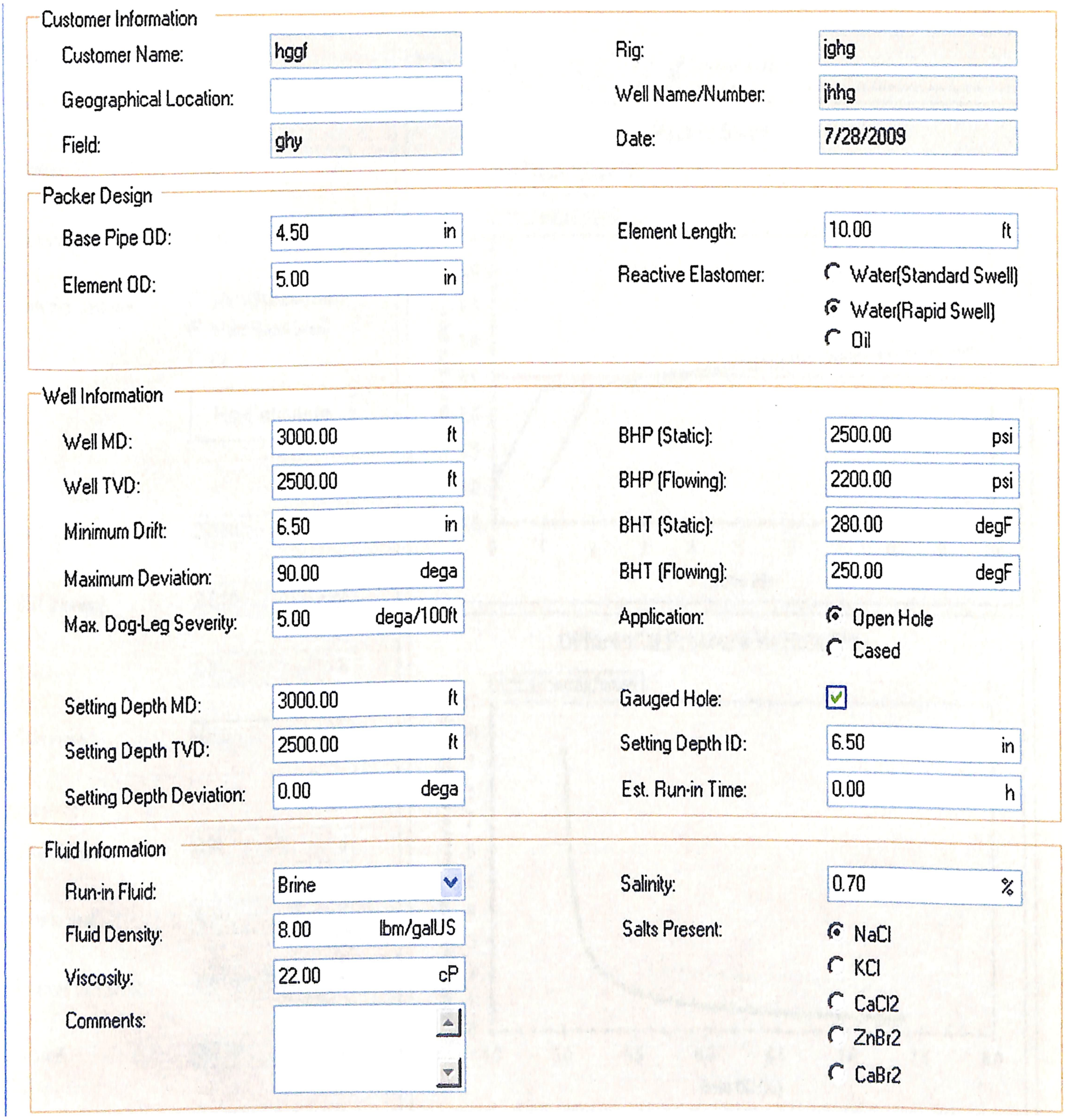


Fig.12.7

The result with the avove conditions:
Time to swell=3.04days, diffrential hold up=585.85 psi

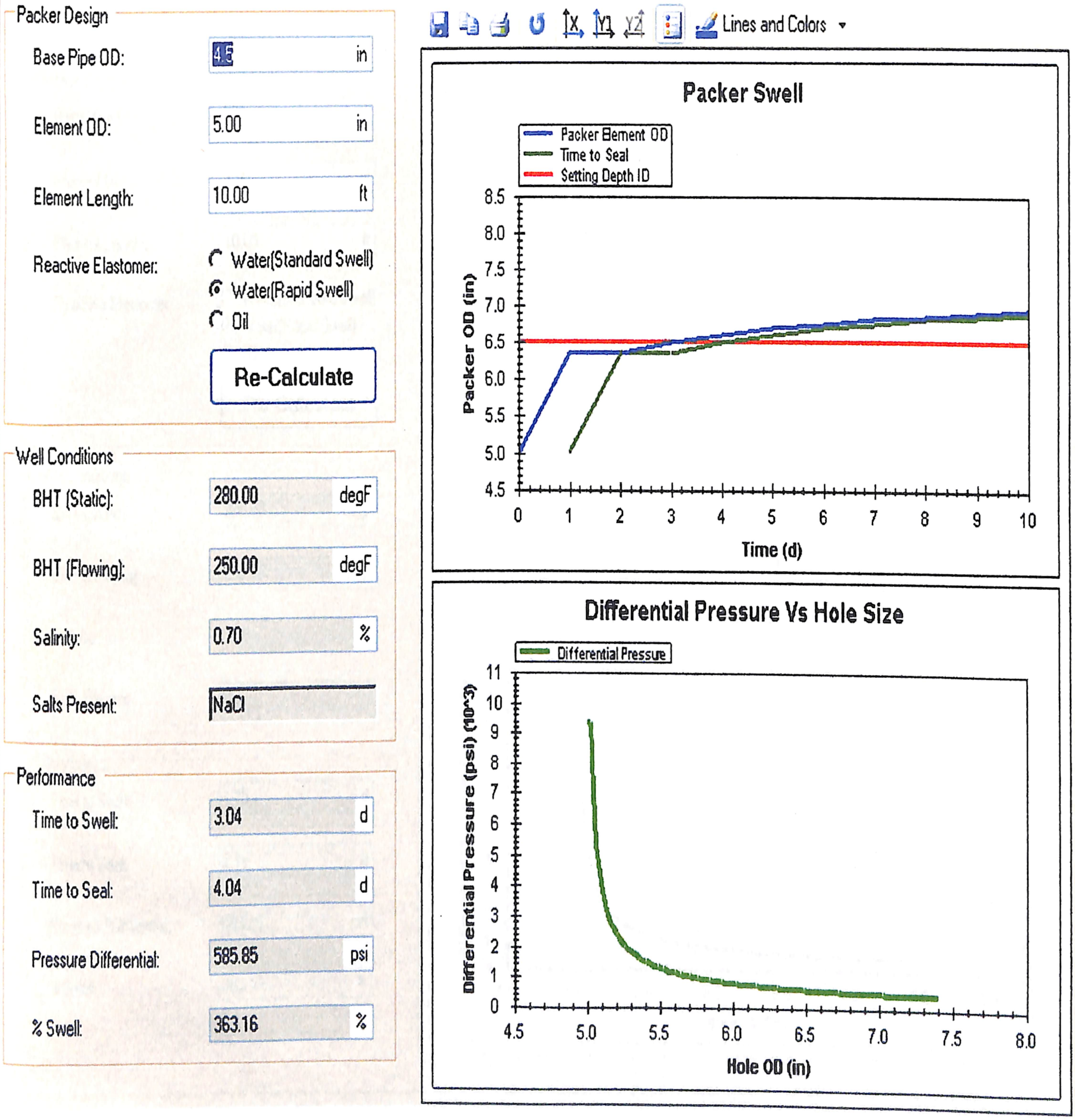


Fig.12.8

If salt present is KCL:

The swell time=1.15 days, diffrential hold up=585.85 psi

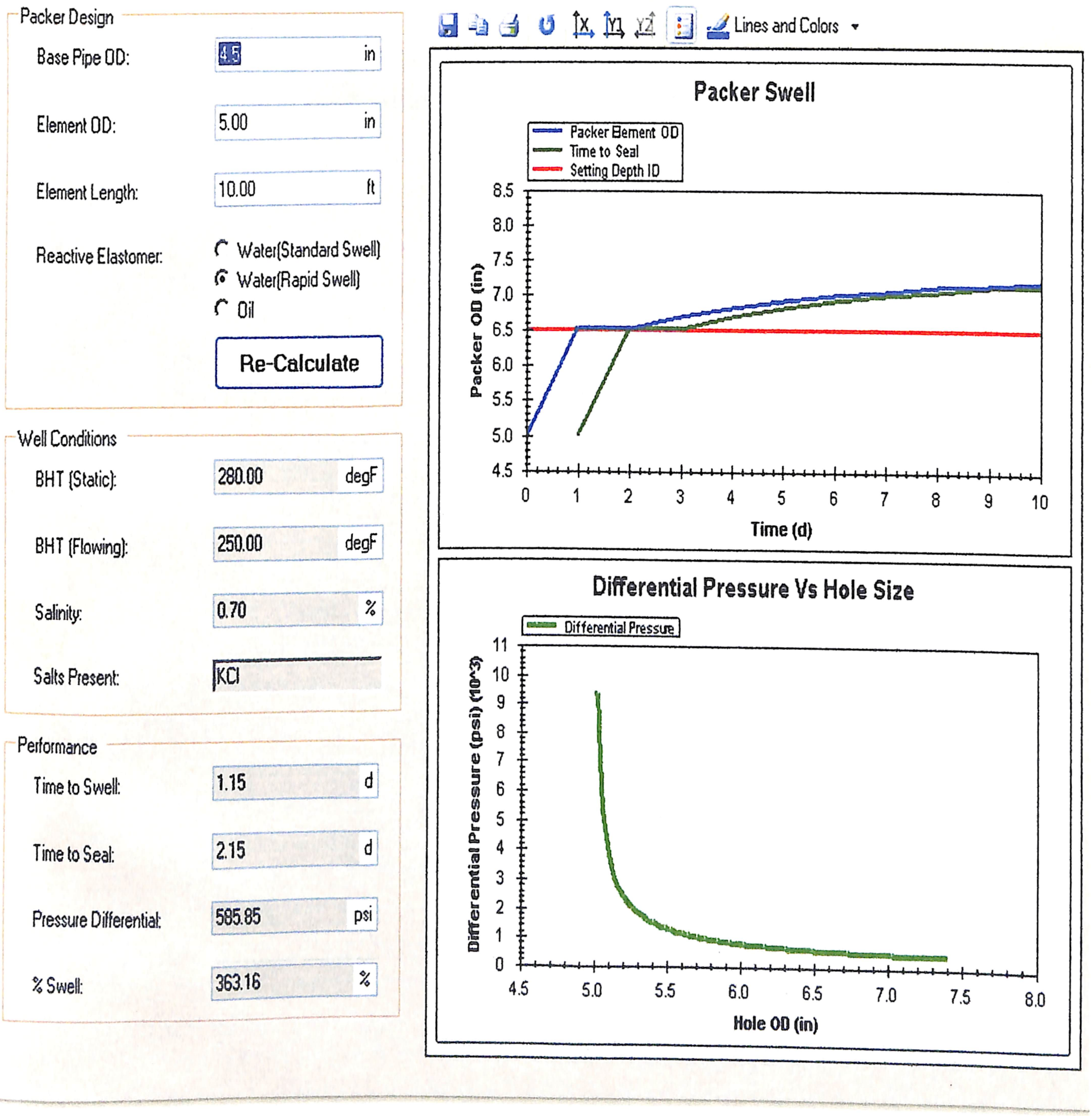


Fig. 12.9

Conclusion of the swell test:

- The time taken to swell is less if the bottom hole temperature is high and if KCL is present instead of Nacl. If the viscosity of the fluid is reduced the swell time also increases.

- The Swell Time is inversely proportinal to the bottom hole temperature and viscosity of the fluid

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