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Preface

This thesis completes my Master's degree in Industrial Economics with engineering specialization in Drilling, and concludes my 5'th and final year at the University of Stavanger.

The topic of the following Master's thesis is "Combining multilateral with IWS completion". The thesis has been completed in collaboration between the Institute of Petroleum Technology at the University of Stavanger and completion engineers at Baker Hughes.

I greatly appreciate the help from my supervisor Jørn Marius Ervik at Baker Hughes for providing me with good ideas and a better understanding of Intelligent Well System. Engineer Morten Myrtvedt at Baker Hughes has provided me with a better understanding of multilateral wells. Finally, I give thanks to Erik Skaugen, for his revue and contribution to this thesis.

Abstract
Intelligent well systems are installed in production or injection wells, to increase the total amount of produced hydrocarbons. An intelligent well system has the advantages of being able to set different choke openings, using hydraulic operated sleeves to regulate the flow of produced or injected fluids.

The procedure of operating the choke from surface without the use of any intervention work, is both economical and less time consuming. Combining the efficiency of intelligent well systems and down hole monitoring systems, such as pressure and temperature gauges, allows for production optimisation. If the down hole monitoring system also is fitted with a multiphase flow meter, surface test separators could be unnecessary.

Multilateral wells are used to reach several pay zones, either within the same reservoir or in different smaller reservoirs. A multilateral well is a single bore well, at the surface, with one or several branches going out from the main bore.

This method of drilling is economical and less time consuming. The equipment costs are lower, due to the need for only one wellhead, less casing costs, lower rig charge etc. Seeing as one only have to drill one main bore, as opposed to drilling separate wells where all wells must be drilled from the seabed, the method is also time saving.

Combining these two solutions, the well will produce from several zones in different reservoirs into one main bore. The production can be controlled and regulated for each zone continuously.

This thesis will describe the equipment used in a combined intelligent well and multilateral solution.

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Introduction

This thesis studies the equipment installed in a well with a combination of Intelligent Well System and multilateral completion, and the advantage of combining the two completion solutions.

1 General well construction [6] [11]

The drilling of a production or an injection well on the Norwegian shelf is generally performed by drilling stepwise down to the designated depth. Formation strength and pressure will determine the safe drilling depth at each step.

Control of the formation pressure is primarily accomplished through use of drilling mud. The drilling mud maintains a pre-determined weight, which provides a hydrostatic pressure that is high enough to prevent the formation fluid to move in to the well bore. As the formation pressure increases, the weight of the drilling mud must be increased, but when the weight of the drilling mud reaches a certain point, the pressure which the drilling mud is causing to the formation is greater than the formation pressure or the formation forces can withstand. At this point the drilling mud will be lost into the formation and continued drilling is not possible. A casing must then be installed to secure the well. Prior to drilling, the formation is analysed by geologists, and the drilling depths are predetermined based on pressure and formation plots.

The first hole to be drilled in a conventional well is typically 30”-36”. The hole is typically 150 meters deep. The section is drilled by using sea water as mud. The reason for using sea water, is that it is not possible to take returns up to the platform due to the fact that the hydrostatic pressure from the platform would be greater than the formation strength.

Casing used in this hole, known as conductors, could also be hammered down in the formation prior to drilling. When hammering down the conductor, cementing is not necessary, but when the conductor section is drilled, the conductor will need to be cemented all the way up to the seabed.

After the conductor is installed, the wellhead is installed on the sea bed. The wellhead is used to hang of the casing that is to be installed in the following sections. Drilling forward from this stage could be done with what is called a pilot hole, if there is a chance of drilling in to a shallow gas pocket drilling with a pilot hole is necessary. A pilot hole is drilled with a smaller diameter drill bit. Shallow gas pockets could be situated as shallow as 200 meters below the sea bed.

The next section to be drilled is usually drilled with a 26” drill bit and typically drilled down to 600 meters. The casing used after drilling the 26” hole is typically 20”, and this casing is also cemented up to the seabed. Continued drilling from this point also requires installation of a blowout preventer (BOP). The requirement of a BOP at this stage, is due to the risk of drilling into pockets with higher pressure. Drilling into a gas pocket could be highly hazardous if there is no way of shutting in the well.

The following section is drilled with a 16" drill bit down to a depth of approximately 1500 meters. Typical casing size used in this section is 13 3/8", and the casing must be cemented at least 300 m above the 20" casing shoe.

After the 13 3/8" casing is installed, the next section is the 12 ¼" section. This section is in many cases drilled down to top of the reservoir, but not into the reservoir. The casing installed in this section is 9 5/8". The 9 5/8" casing is typically cemented 200-300 meters from the 9 5/8" casing shoe and up towards the surface.

Penetration of the reservoir is then performed using a 8 ½" drill bit or a 6 ½" drill bit. A liner is typically installed through the reservoir and anchored in the bottom of the 9 5/8" casing using a liner hanger and. Liners are usually consist of 7" or 5 ½" casing, When the liners are installed with casing, the entire liner length is cemented, from the bottom of the liner and up to the liner hanger. Another option is to install the liner with sand screens, if sand screens are installed cementing of the liner is not performed. Sand screens could be installed with or without a gravel pack. A gravel pack is when gravel is pumped down and placed around the sand screens to prevent reservoir formation debris to be produced, the gravel is acting like a filter.

Liners are typically run with a polish bore receptacle (PBR) on top of the liner hanger. At a later point in the well construction, the production tubing will sting into the liner PBR, allowing access down into the reservoir for future well intervention.

2 Multilateral completion [10] [12] [13] [19] [35]

Optimizing the production, reducing the cost and maximizing the reserve recovery, the petroleum industry has developed and used the multilateral technology for many years. Basic multilateral wells were developed in the 1950's.

A multilateral well is a single well at the top, with one or more wellbore branches radiating from the main borehole below the sea floor. Multilateral wells can be as simple as a horizontal well with one branch, or as complex as an horizontal extended reach well drilled with multiple laterals and sub lateral branches. Multilateral well design includes multibranched wells, forked wells, wells with several laterals branching from one horizontal main wellbore, wells with several laterals branching from one vertical main wellbore, wells with stacked laterals and wells with dual-opposing laterals. Generally these wells would represent one of two basic types of multilateral solutions, vertically staggered laterals and horizontal spread laterals in fan, spine and rib or dual opposing T-shapes.

Vertically staggered wells are used if it is possible to target several different producing horizons in order to increase production rates and also increase recovery from multiple zones by a commingling production. Production is a function of the present number of natural fractures in the well and how the well bore encounters these fractures. When drilling a horizontal well, there is a greater chance of intersecting the natural fractures are higher than with a vertical well. However, there is a limit to how long a horizontal well can be drilled. Encountering more of the natural fractures could therefore be achieved by drilling several laterals from the same well bore.

Horizontal fan wells use their branches to target the same reservoir interval. The use of multiple branches in the same reservoir interval can increase production rates, improve hydrocarbon recovery and maximize production in that particular zone. Several thin reservoir layers can be drained by varying the inclination and the vertical depth of the different drain holes. If the natural fractures have an unknown or variable fracture orientation, the chances of encountering these fractures can be improved by using a fan configuration.

When the orientation of the fractures is known, the use of a dual-opposing T-well can allow the length of the lateral wellbore exposure to be doubled.
Reservoirs with nonfractured, matrix-permeability, the spine-and-rib design reduce the tendency to cone water.

A multilateral well that has been successfully installed, can replace several vertical wellbores, which again can reduce overall cost of drilling and completion of a field. Increased production and more efficient drainage of a reservoir, are also among the benefits of using a multilateral well.

Multilateral completion is a technology that has been used for some time, and is a method used in well construction if the goal is to drill a multi-branched well. There are different strategies to choose from when planning an multilateral well, vertical, inclined, horizontal and extended reach wells.

Multilateral technology is applicable both for new oil and gas wells and also for existing wells. Geometric solutions for multilateral wells are wide-ranging, figure 2-1, illustrate some of the solutions available. Which solution that is best suited in a specific case is determined by a number of factors, such as pressure, temperature, zonal segregation and isolation requirements, lateral wellbore rock properties and stability, workover/re-entry options, abandonment requirements and sand/water production.

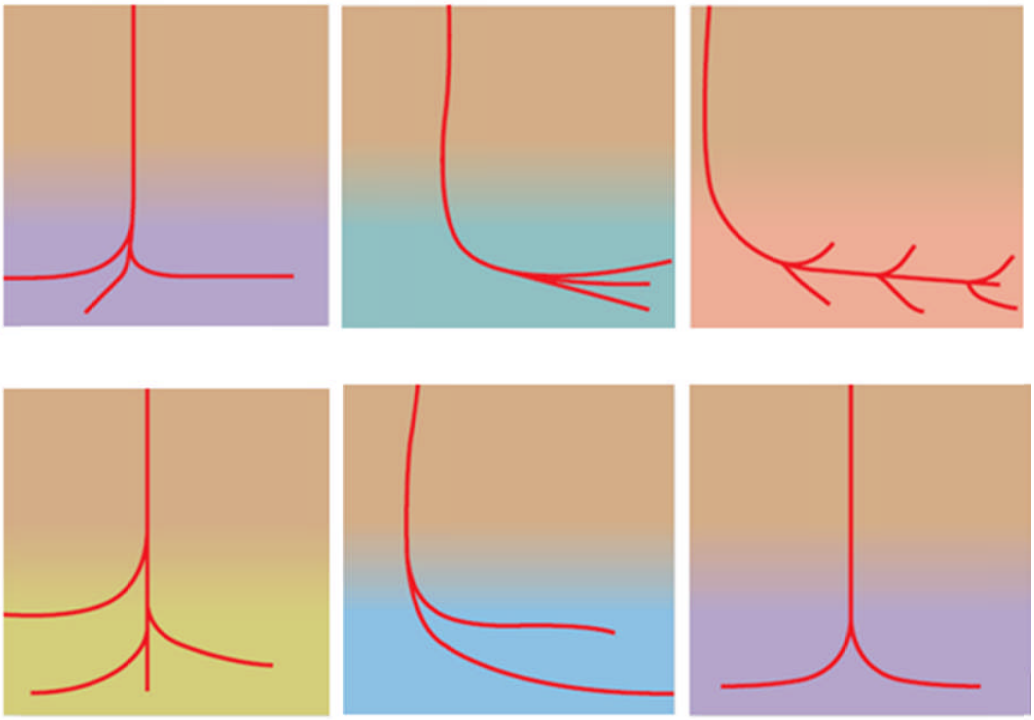

Figure 2-1- Types of multilateral wells [12]

Multilateral wells can be divided in to three major categories, openhole multilateral wells, limited-isolation/access multilateral wells and complete multilateral wells.

Advantages and disadvantages with multilateral wells are approximately the same as for horizontal wells. Advantages compared to traditional wells include higher productivity index, the possibility of draining relatively thin hydrocarbon layers, decreased water and gas coning, increased exposure to natural fracture systems and better sweep efficiencies. Seen from a drilling point of view, the multilateral wells can be drilled with existing surface installations.

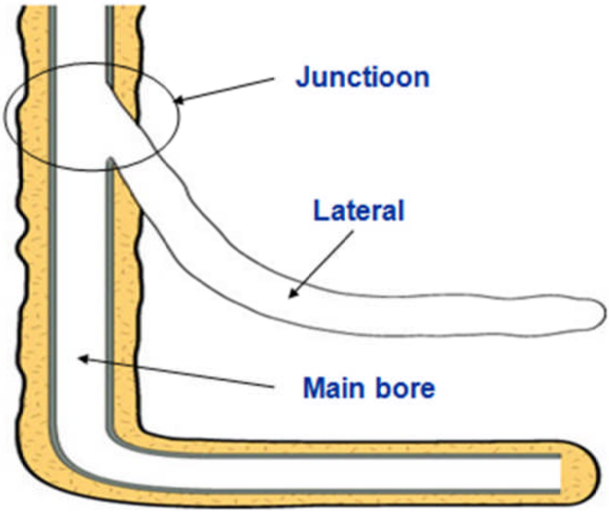

Figure 2-2- Segment of multilateral wells [12]

To further separate and categorize the technology used in multilateral wells, a system called technology advancement of multilateral (TAML) has been developed, the system is used based on the amount and type of support provided in the junction. TAML is a ranging system with levels 1-6 and 6s, see figures 2-3 – 2-10. As the level increases, so does the complexity of the design.

The evaluation of multilateral wells is primarily done using three characteristics; connectivity, isolation and accessibility. The connectivity or junction that combines the main bore and the lateral branches is not only the most risky and distinguishing feature of a multilateral well, it is also the most difficult part of drilling a multilateral well.

2.1 Level 1 [10] [12] [13] [19]

Figure 2-3- TAML level 1 [35]

The level 1multilateral well, see figure 2-3, is the most fundamental of the multilateral wells, and provides an option with an openhole main bore and lateral. In a level 1 well, the main bore and lateral branches are always openhole, and the junction is left unsupported.

Access to the lateral with a level 1 well is reduced, and any type of production control is not possible. Commingled production is the only option with a level 1 multilateral well. When using a level 1 option, it is possible to install an unsupported slotted liner or screen in the lateral or the main bore.

2.2 Level 2 [10] [12] [13] [19]

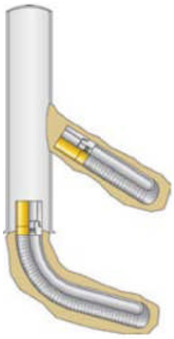

Figure 2-4- TAML level 2 [35]

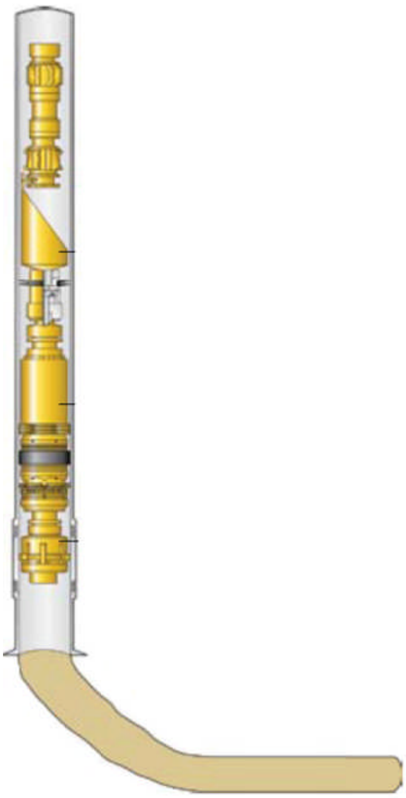

Figure 2-5- Show whipstock installation [35]

Level 2, figure 2-4, provides an option with a cased and cemented main bore with an openhole lateral. It is possible to set an unsupported slotted liner or screen in the lateral. Access to the lateral with a level 2 well is limited, but improved compared to a level 1 well.

A level 2 well is constructed by first drilling the main bore, then using a whipstock system to create a casing exit window. Figure 2-5, shows the whipstock installed and the milling assembly ready to mill the window. Through this window, the lateral bore is later on drilled. Installation of the whipstock is performed using Measurement While Drilling (MWD) to orientate the whipstock face, meaning that the window will be milled towards the designated coordinates.

2.3 Level 3 [10] [12] [13] [19]

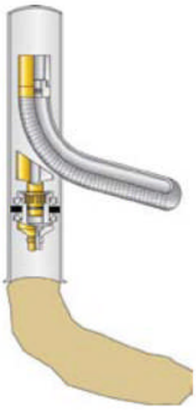

Figure 2-6- TAML level 3 [35]

Level 3, figure 2-6, provides an option with cased and cemented main bore and a cased lateral. A slotted liner or screen is set in the lateral and anchored back into the main bore casing, and the lateral is not cemented. Level 3 is the first of the TAML levels to offer a mechanical support at the junction. In a level 3 well, multilateral technology access to the lateral is possible. Construction of the lateral in level 3 is similar to level 2, a casing exit window in the casing has to be milled prior to commencing drilling the lateral section.

2.4 Level 4 [10] [12] [13] [19]

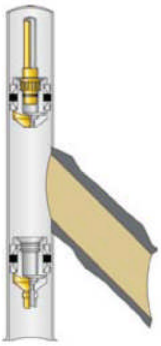

Figure 2-7- TAML level 4 [35]

Level 4, figure 2-7, provides an option with a cased and cemented main bore and lateral. The lateral is now cemented and has a mechanical support, but the cement does not offer any pressure integrity at the junction. Access to both main bore and lateral is now possible. The casing exit window is also the preferred method of getting from the main bore to the lateral.

2.5 Level 5 [10] [12] [13] [19]

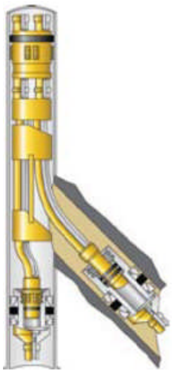

Figure 2-8- TAML level 5 [35]

Level 5, figure 2-8, provides an option with a cased and cemented main bore and lateral. Pressure integrity in the junction from produced or injected fluids is now achieved by the installed completion. Cement is not acceptable as the hydraulic isolation. Reentry access to both the lateral and the main bore is available.

2.6 Level 6 [10] [12] [13] [19]

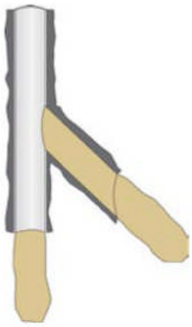

Figure 2-9- TAML level 6 [35]

Level 6, figure 2-9, provides an option with mechanical and pressure integrity at the junction, achieved by using the casing to seal the junction. Pressure integrity in the junction is achieved with a formable metal designed junction, or with an integral sealing feature.

2.7 Level 6s [10] [12] [13] [19]

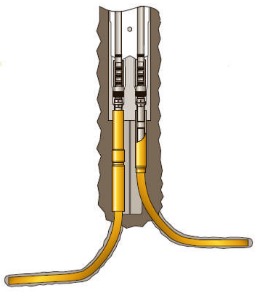

Figure 2-10- TAML level 6s [35]

Level 6s, figure 2-10, is a sub level of level 6. Level 6s uses a down hole splitter or a subsurface wellhead, that splits the main bore in two smaller, lateral bores.

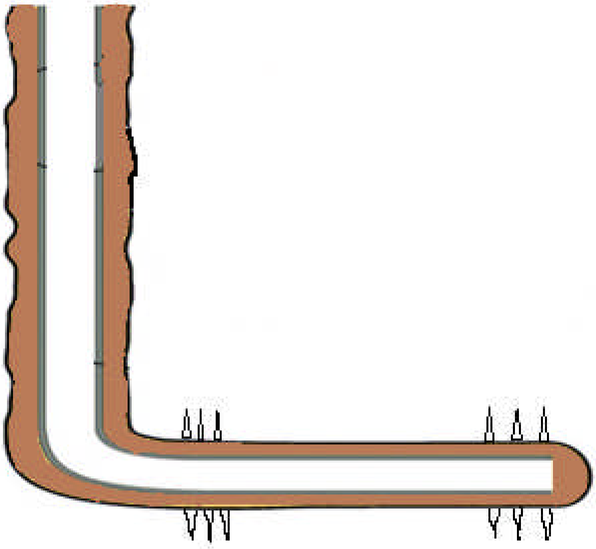

Figure 2-11- Horizontal perforated well

Figure 2-11, illustrates a horizontal well with two perforations. In wells shaped like this, similar to a foot, one refers to the perforations to the right as to the perforations in the toe. The perforations to the left are referred to as the perforations in the heel.

Reservoir fluids flowing from the toe to the heel, will experience a pressure drop due to friction. This pressure drop needs to be considered prior to drilling the well. If the well is long or is designed with a small internal diameter in the production tubing, the frictional pressure drop from the toe to the heel could result in it being impossible to produce from the toe.

2.8 Whipstock [21]

Figure 2-12- Whipstock assembly [21]

Figure 2-13- Casing mill for whipstock [21]

When the main bore is drilled and the liner is installed, the lateral must be opened. To open the lateral bore, it is necessary to use a whipstock. A whipstock is an assembly consisting of two parts, the wedge and the mill, connected to each other with a shear pin.

The whipstock is usually run with a MWD tool, and this allows for orientation of the wedge. If run without MWD, the whipstock could also be oriented using a gyro.

When the whipstock is run to its designated depth, circulation is started in order to make it possible to read the signals from the MWD tools. Orientation of the Whipstock is then possible. After orienting the wedge in the right direction, the whipstock can be set mechanically or hydraulically.

After the wedge is oriented and locked onto the casing, the mill needs to be released. Releasing of the mill is performed by pulling the drill pipe until the shear pin holding the milling assembly and the wedge shears. When the mill is released from the wedge, the window can be drilled.

After penetrating the casing, it is necessary to continue milling out into the formation to prepare the starting point for the drill bit used on the drill string used to drill the lateral. In order to let the mill located further back on the milling assembly, the watermelon mill, drill the required inner diameter of the bore hole. When milling in to the formation, it also becomes easier to start drilling with the regular drilling equipment.

When the lateral is drilled to its designated length and depth, the wedge needs to be retrieved. Retrieving the wedge is done using a pulling tool shaped like a key, see figure 2-14. The pulling tool for pulling the wedge is designed to fit into the groove as shown in figure 2-15. Retrieving of the wedge is performed by running the retrieving tool together with a MWD tool to the top of the wedge. Due to the drilling of the lateral and milling of the casing window, the groove made for retrieving the wedge is usually packed with debris. Nozzles are therefore installed in the retrieving tool, and to be able to align the nozzles with the grove it is necessary to use the MWD. After the debris has been washed away, the MWD will again be used to align the retrieving tool to the groove in the wedge. Release of the wedge is completed by latching the retrieving tool to the wedge and performing a straight pull.

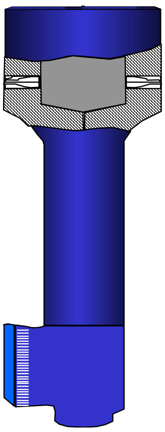

Figure 2-14- Used whipstock [21]

Figure 2-15- Retrieving tool for whipstock [21]

3 Intelligent well systems (IWS) completion

Intelligent well systems are defined as systems with the ability to monitor and remotely control injection/production downhole and the ability to respond quickly to (un)expected changes in reservoir performance.

Intelligent well systems are systems that allows for surface control of both production and injection. Hydraulic sleeves are installed in the well and can be operated from a surface control panel. Operation of theses sleeves means changing the choke opening of the sleeves.

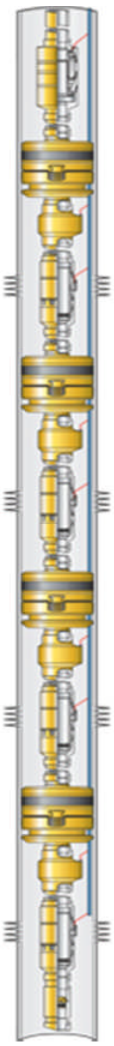

Figure 3-1- IWS zonal completion [25]

3.1 Standard flow [9] [26]

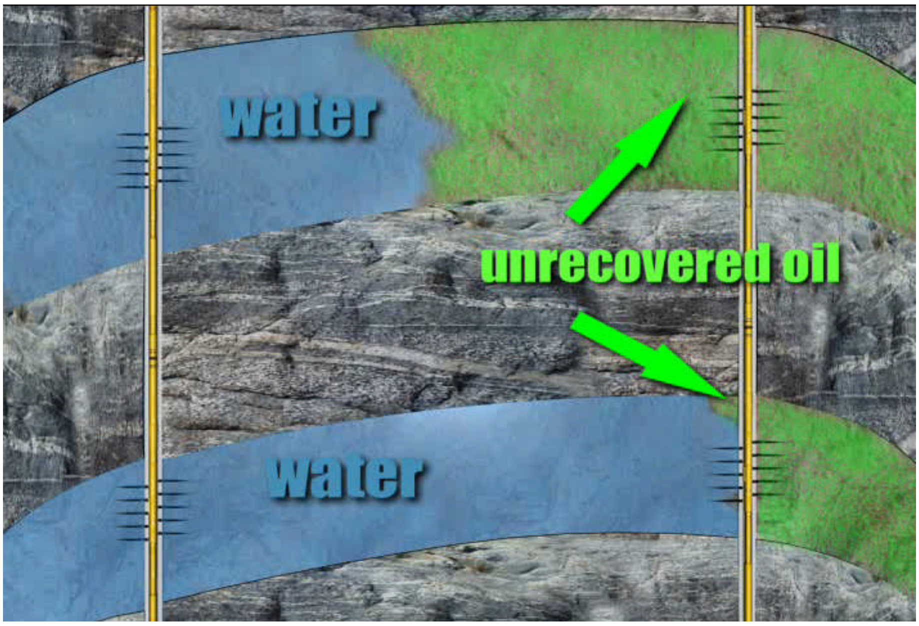

Figure 3-2- Water injection without hydraulic operated choke [26]

Figure 3-2, illustrates a standard injection well to the left and a standard production well to the right. Both wells have two zones, and the reservoir parameters are clearly different in both zones.

In the lower zone, injection water is about to reach the perforating's. When the water reaches the perforating's, the well will start to produce water and intervention work needs to be carried out to seal off the lower production and injection zone.

3.2 Optimized flow [9] [26]

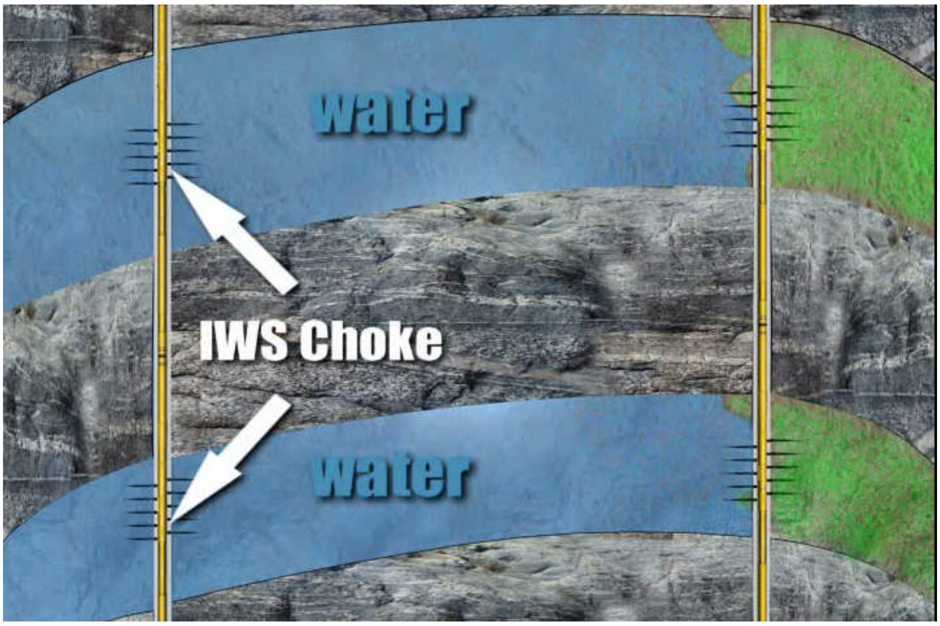

Figure 3-3- Water injection with hydraulic operated choke [26]

Figure3-3, illustrates the use of hydraulic operated sleeves with adjustable chokes. When using the adjustable chokes, it is possible to choke both the injection choke and the production choke. With the possibility to control the opening diameter of both the injection and the production zone, it is possible to produce more of the hydrocarbons in the reservoir.

3.3 Water coning [9] [11] [26]

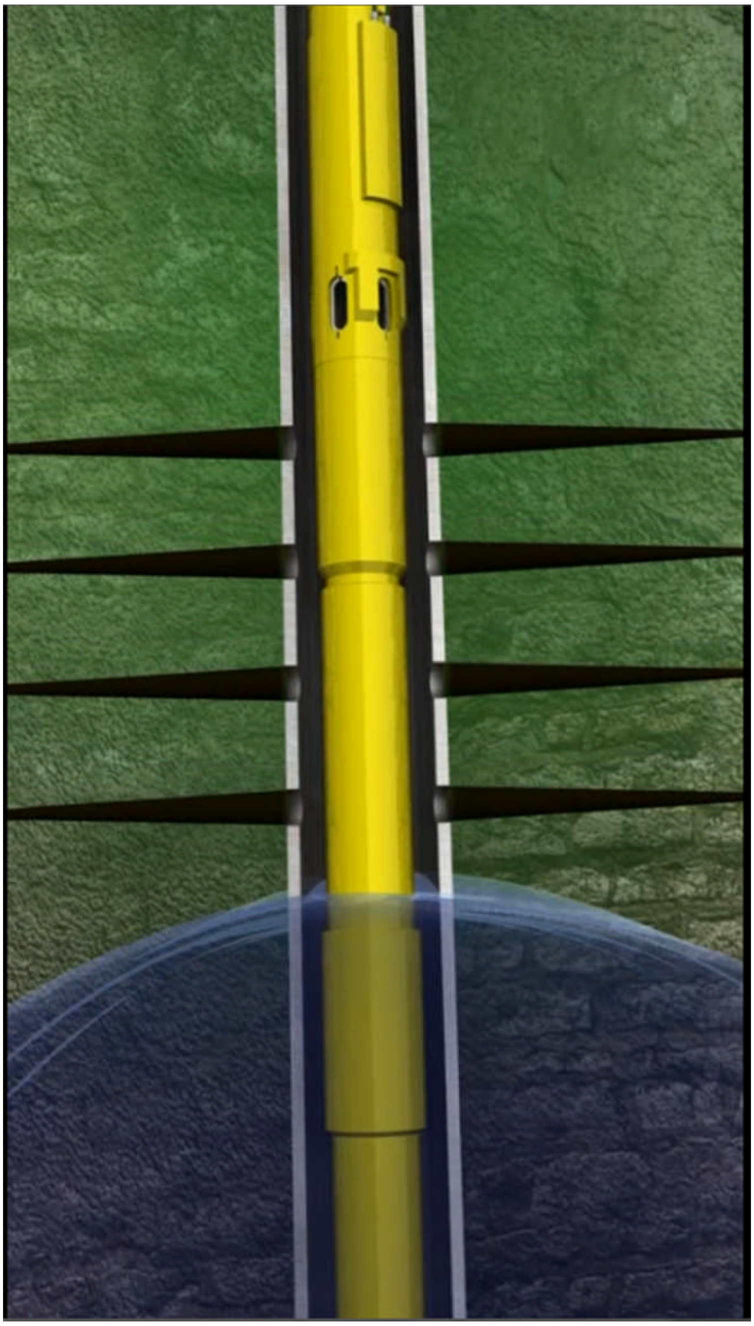

Figure 3-4- Controlling water coning with hydraulic operated choke [32]

Water coning during production is a problem that occurs. It is difficult to prevent water coning from occurring, but it is a possibility to close the sleeve when the well is producing water. When the sleeve is kept closed for a given time interval, the water cone will diminish. After the water cone has drawn back, the production of hydrocarbons can be continued.

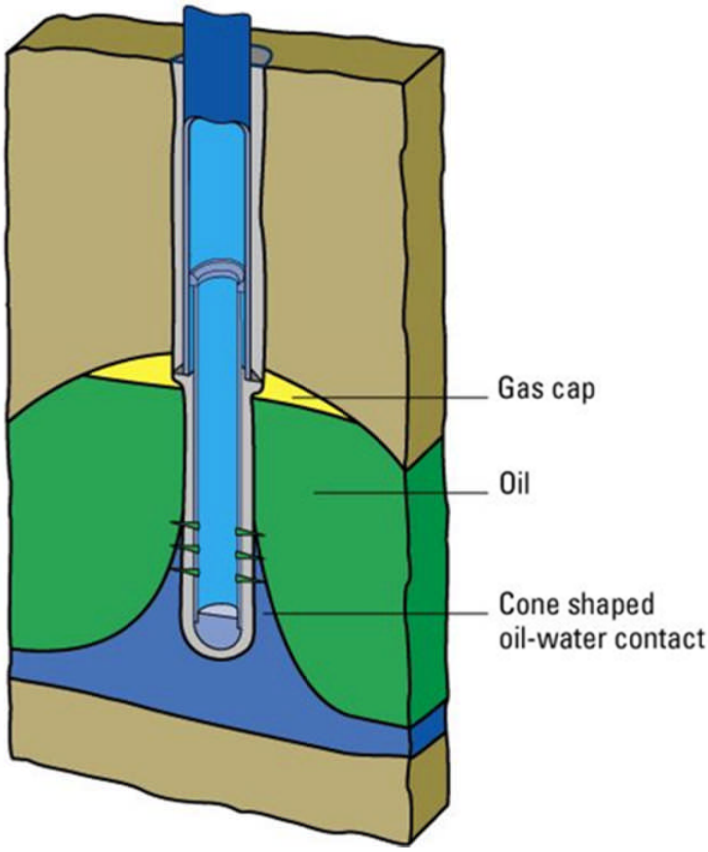

Figure 3-5- Illustrates a water coning scenario [65]

Figure 3-5 illustrates a reservoir with oil in the middle, gas on top and a layer of water below the oil.

When the well is producing, there is a difference ΔP between pressure on the inside and the outside of the production tubing. The pressure outside the production tubing is greater than the pressure on the inside of the production tubing. This pressure difference, ΔP, is known as the drawdown pressure.

When the oil starts to flow into the well, the pressure of the oil lying around the perforations is reduced. This reduction in pressure will allow the water in the layer below the oil to rise, due to the pressure of the water now being higher than the pressure of the flowing oil. As the water starts to rise and reaches the perforations, the water displaces the oil and is produced.

A water cone could be quite high. For example, the drawdown pressure could be 20 bar, the formation fluid could have a weight of 1020 kg/m^3 and the reservoir oil could have a weight of 790 kg/m^3. The drawdown pressure could be expressed with equation 3.1.

$$\Delta P = (\rho_w - \rho_o) g h_w \qquad 3.1$$

This lead to:

$$h_w = \frac{\Delta P}{(\rho_w - \rho_o) g} = \frac{20 * 10^5}{320 * 9{,}81} = 637m \qquad 3.2$$

Where:
$h_w = height\ of\ water$
$\rho_w = weigth\ of\ water$
$\rho_o = weight\ of\ oil$

In this example, the water cone will have a height of 637m.

To prevent the water cone from reaching the perforations, a hydraulic operated sleeve with a choke could be installed in the well. With the ability to choke the opening of the production tubing and, if needed, the ability to close the choke completely, the water cone can be prevented from entering the production tubing

3.4 Gas coning [9] [26]

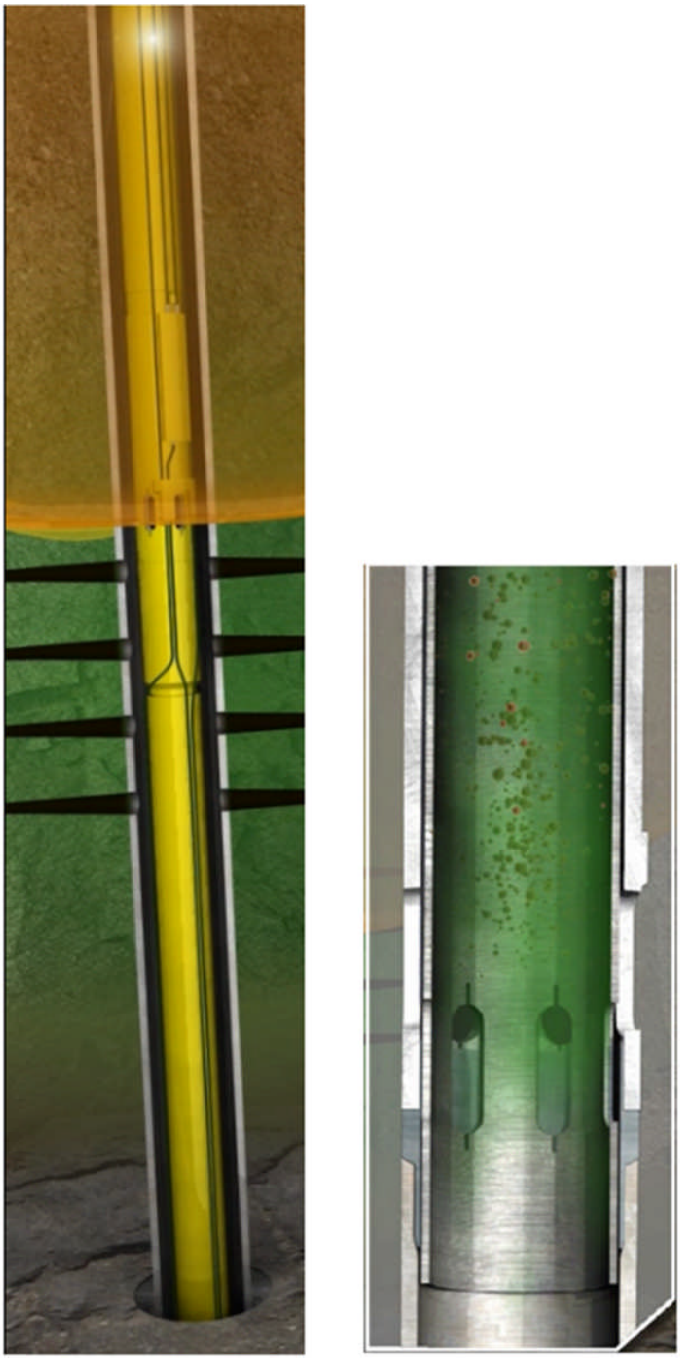

Figure 3-6- Controlling gas production with hydraulic choke [32]

Figure 3-6, illustrate a scenario where injected gas or a gas cap is lying above the perforations. The drawdown of the gas will then lead to gas production. Using a hydraulic operated sleeve with possibilities of changing the choke opening, will allow for stabilizing the gas cap. And the gas cap is stable at a level where it will not be drawn down to the perforations and produced. A gas cone will form due the same reason that the water cone will form, described in chapter 3.4.

3.5 Single line switch [9] [26] [29]

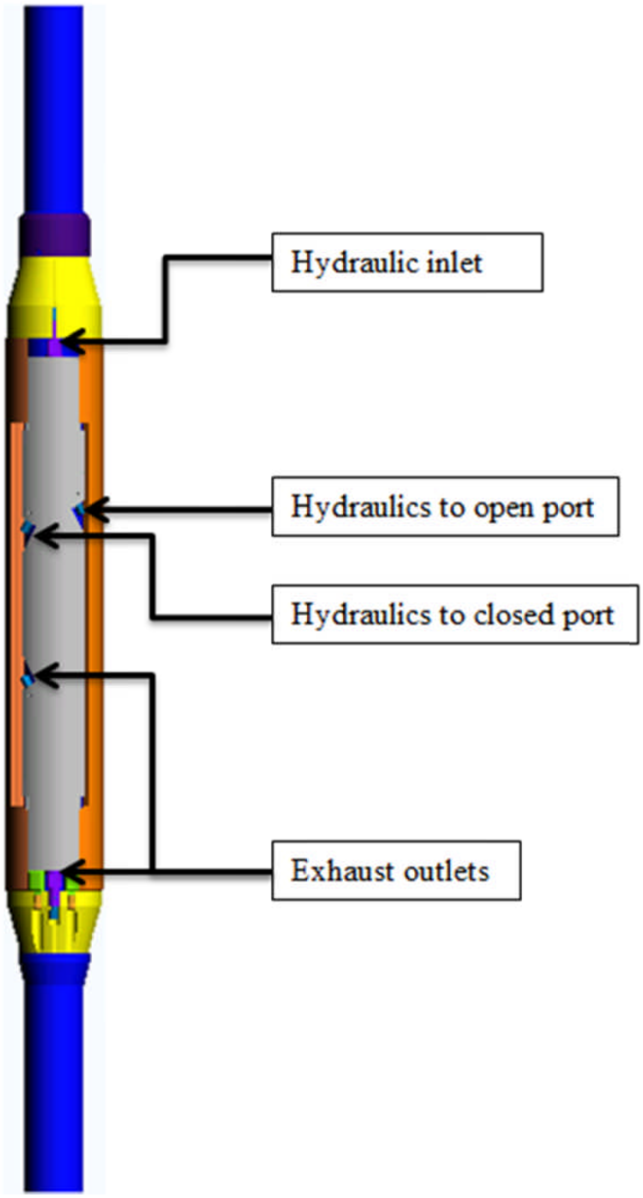

Figure 3-7- Single line switch [29]

If it is desirable to produce from several zones, it is necessary to install several sleeves. In some cases it tends to be a challenge with the amount of hydraulic control line ports in the tubing hanger, and outlets on the wellhead to terminate the desired amount of control lines needed to operate the sleeves. As a solution to this problem, there is designed a tool called a single line switch (SLS). The use of SLS has increased the number of solutions of IWS completion solutions. The SLS is a tool that routs the hydraulic fluid from one control line going from the surface down to two separate control lines that operates the hydraulic sleeve. The SLS is designed with inlet and outlet ports as illustrated in figure 3-7. Inside the SLS there is a moving piston, witch routs the hydraulics between open port and closed port every other time the SLS is pressurized. It is this feature that allows operation of a sleeve with only one control line.

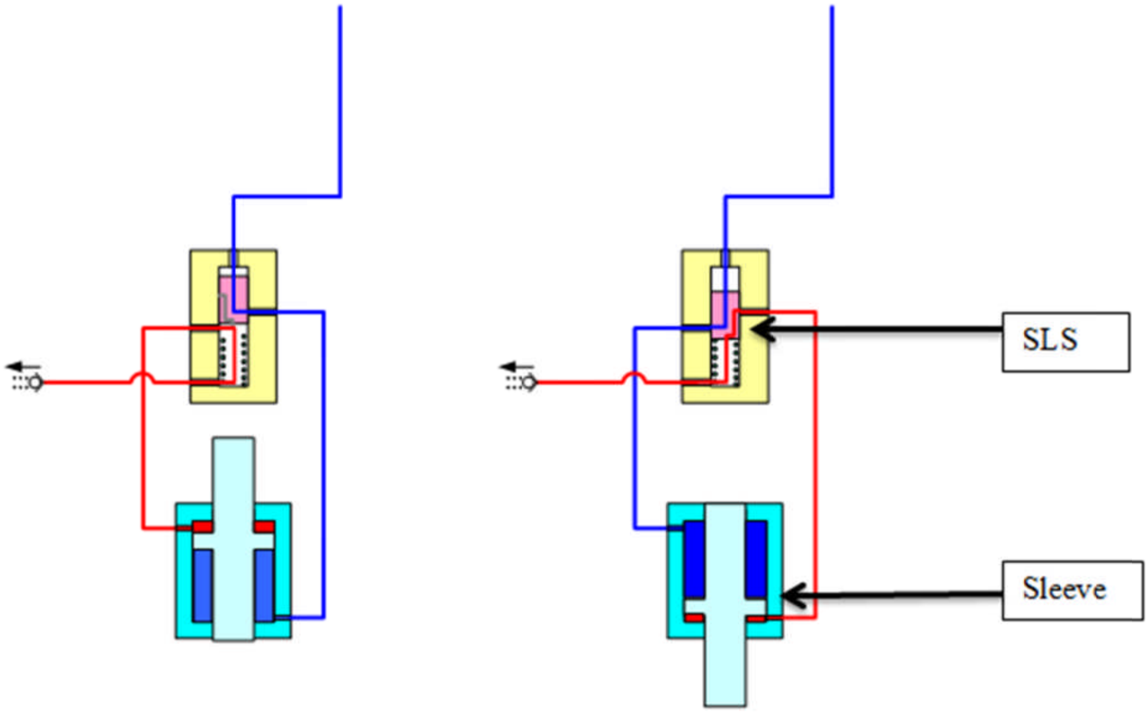

Figure 3-8- Control line configuration 2x1 system [29]

Figure 3-8, illustrate how the SLS is connected to the sleeve. The exhaust is connected to a one way valve and dumped into the well. The blue control line is connected to the surface, and the red control line is installed from the sleeve and typically stopped just above the production packer. This means that when the exhaust is dumped, this is done above the production packer. This system is referred to as a 2 x 1 system.

If the sleeve is not just open or closed, but is a choke, it is necessary to measure the returns from the close/exhaust line to be certain of the choke position. Usually the sleeve needs two control lines to be able to operate, but when running several sleeves and combining the sleeves with the use of SLS, it is possible to reduce the acquired amount of control lines required to operate the sleeves.

Figure 3-8, which is called a 2 x 2 system, consists of two SLS's and two sleeves. It is possible to operate this system with only two control lines going from the system to the surface, instead of four control lines which would be the alternative if there were no SLS installed. Reducing the amount of control lines by two may not seem that necessary, but when installing a IWS completion with several 2 x 2 systems, the maximum available feed through ports in the wellhead and tubing hanger will be full, and it is necessary to reduce the amount of control lines to be able to get as many zones as required.

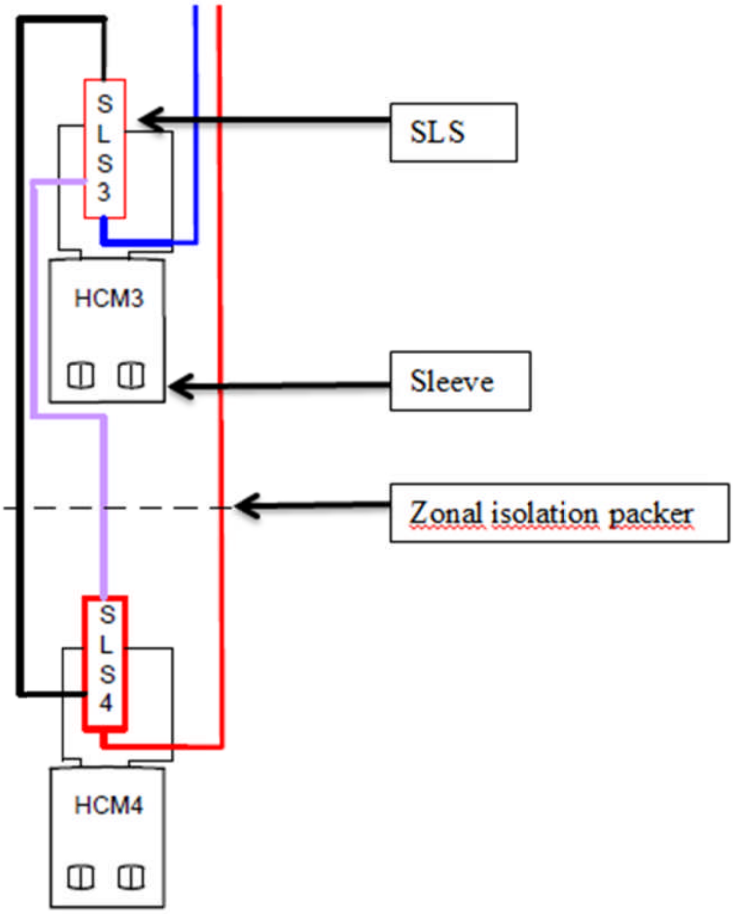

Figure 3-9- Control line configuration 2x2 system [29]

Figure 3-9 illustrates the control line configuration in a 2 x 2 system. To operate the upper sleeve HCM3, pressurizing the red control line, the SLS 4 will then be pressurized and hydraulic fluid will be lead into the black control line leading to the top of SLS 3. From the SLS 3, the hydraulic fluid will be guided down to the HCM 3, and the sleeve will be operated.

When the hydraulics has been routed to the SLS 3, this SLS will alternate between the two control lines connected from the SLS 3 to the HCM 3. This is in order to alternate between opening and closing the sleeve. The return fluid will then be guided up through the blue control line and the return volume can be measured on surface. The reason for monitoring the returns is that there are different returns from the different positions, due to the J-slot configuration of the sleeve, chapter 4.2.11

4 Combining IWS and multilateral

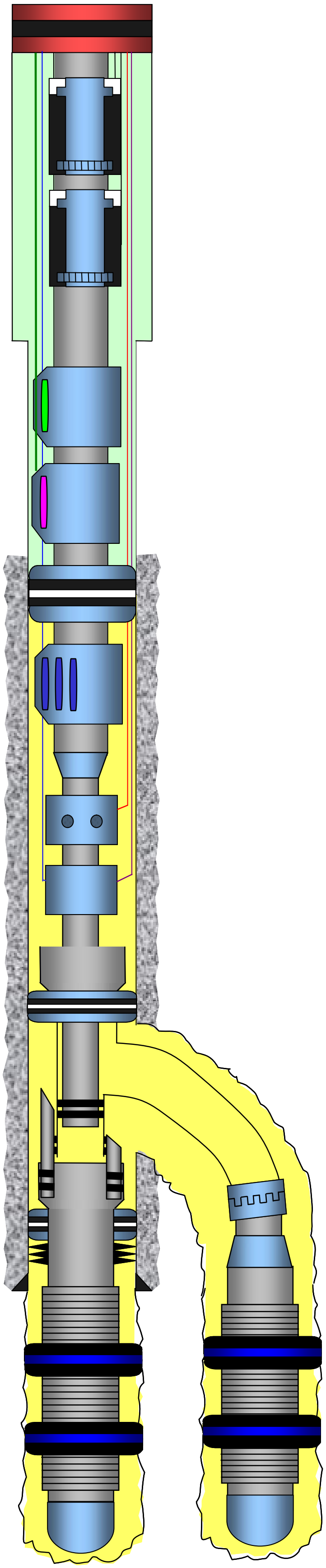

Figure 4-1- Combining multilateral and IWS completion

4.1 Equipment used in this well:

The next chapter will in detail review the equipment needed for a combined IWS and multilateral completion solution. The review starts from the top of the well. In appendix B-F, each phase of the well construction is illustrated.

4.2 Main bore

4.2.1 X-mas tree [5] [9] [36]

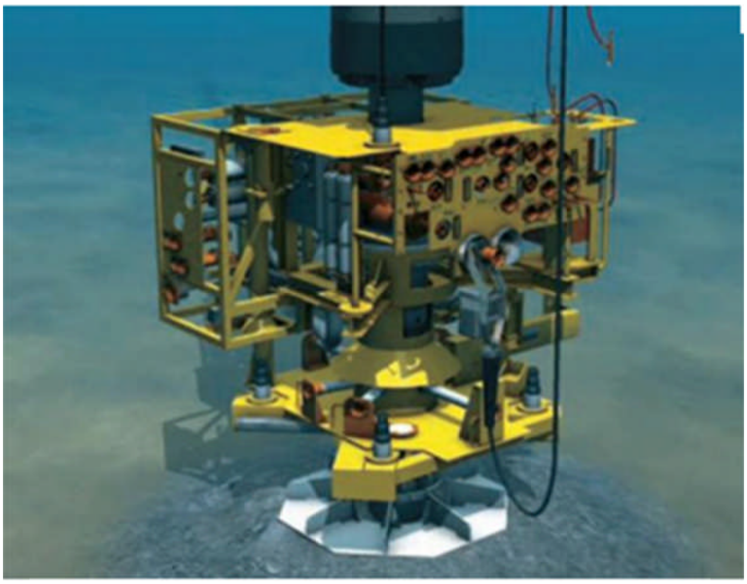

Figure 4-2- Subsea x-mas tree [36]

A subsea X-mas tree contains several valves that are used for testing, choking, servicing and regulating the stream of oil and gas that is produced. The primary function of the X-mas tree is to control the well stream going from the well to its storage facility, either onshore or offshore. Two different types of X-mas trees exist for subsea use, the vertical and the horizontal X-mas tree.

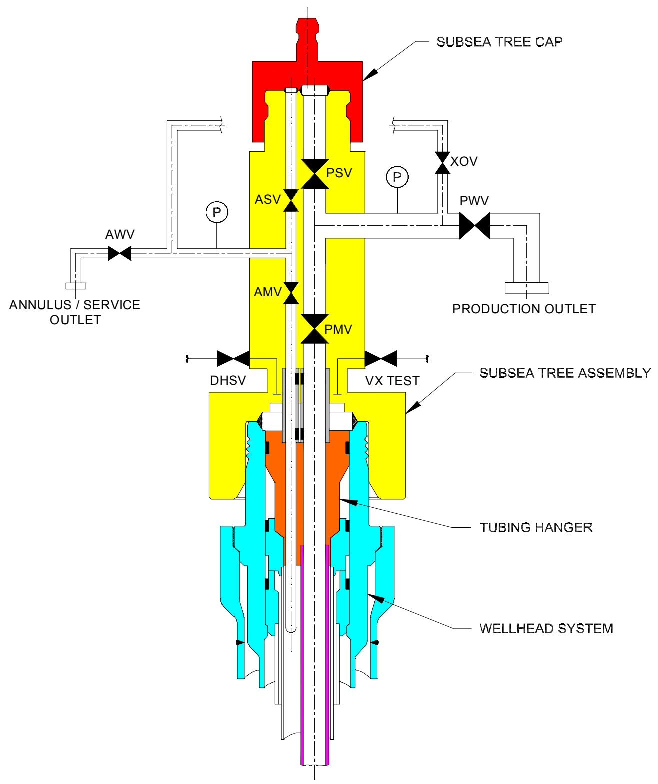

Figure 4-3- Vertical x-mas tree [26]

A vertical tree, figure 4-3, is designed with the several valves stacked vertically on top of the tubing hanger. Operation of the down hole functions is provided through the bottom of the tree to the top of the tubing hanger through hydraulic and electric connectors. When a vertical tree is used, the production tubing and the tubing hanger is installed prior to installing the X-mas tree.

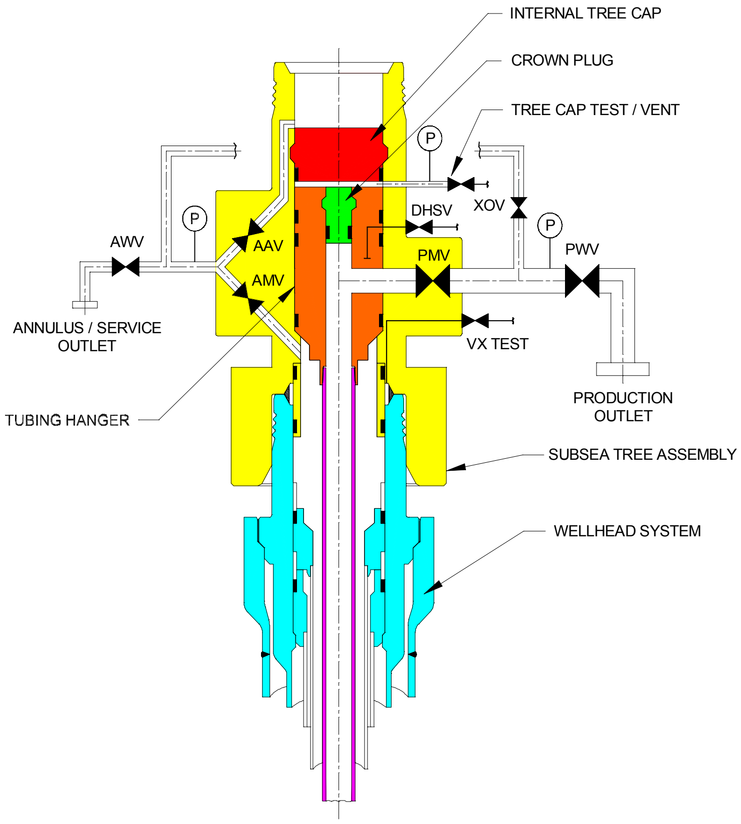

Figure 4-4- Horizontal x-mas tree [26]

A horizontal X-mas tree, figure 4-4, routs the well stream out sideways through the tubing hanger, and further through a production flowline with a horizontal valve configuration. The operating of down hole functions is accomplished by using radial penetrators into the side of the tubing hanger. When using a horizontal X-mas tree, the tree is installed prior to running the completion.

4.2.2 Tubing hanger [5] [37]

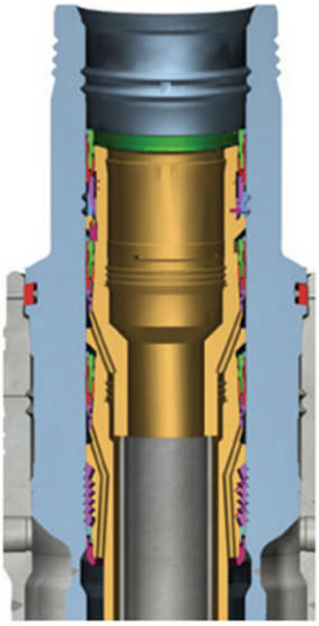

Figure 4-5- Tubing hanger [37]

A tubing hanger is the last completion assembly to be installed in the tubing string. The tubing hanger is designed to land and seal into the wellhead. When the tubing hanger is landed in the wellhead, it will be locked mechanically to the wellhead. The tubing hanger is also fitted with seals, usually with both metal and elastomer-seal.

Control lines rising from the well, also needs to be connected to the tubing hanger. The control lines are pressure tested or signal tested after they are connected to the tubing hanger. The seals on the tubing hanger are pressure tested after tubing hanger is landed and locked to the wellhead.

4.2.3 TRSCSSV [5] [9] [38] [39]

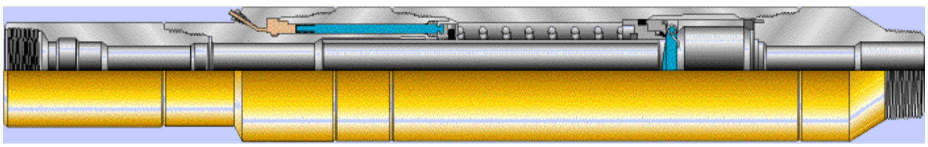

Figure 4-6- Tubing retrievable surface controlled sub surface safety valve [39]

A tubing Retrievable Surface Controlled Sub Surface Safety Valve (TRSCSSV) is used to prevent reservoir fluid to be able to flow from the reservoir to the surface if it is not intended to do so. There are primarily two types of TRSCSSV in use today, the ball valve and the flapper valve. The most used type of TRSCSSV is the flapper type.

The TRSCSSV is a failsafe closed valve, and the intention with this type of valve is that it needs hydraulic pressure to stay in the open position. To achieve hydraulic pressure down hole at the valve pressure is transmitted through a ¼” hydraulic control line. The control line is installed from the TRSCSSV and to the platform that controls the production of the well. Hydraulic fluid is present in the control line and is pressurised from the platform. When the valve loses its hydraulic pressure, the valve will close and stop the flow of hydrocarbons.

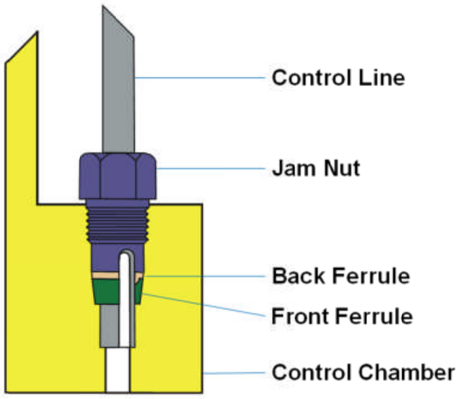

Figure 4-7- Control line connection [28]

In this well there are installed two TRSCSSV’s. The purpose of installing two valves is to have one in backup in case of failure to the other one. This is a typical solution for sub-sea wells. There are two main reasons for using this solution in sub-sea wells, the cost of a floating drilling rig for doing intervention work on a sub-sea well is very high, and the availability of floating drilling rigs is limited.

When two TRSCSSV’s are installed, it is possible to use an intervention ship to do maintenance on the TRSCSSV, and if one of the valves is dysfunctional it can be permanently locked open. This does not require any recompletion, and can therefore be conducted by an intervention vessel.

The installation depth of the TRSCSSV is critical for the valve to be functional. In Norway, the petroleum legislation requires the TRSCSSV to be installed minimum 50 meters below the sea bed [7]. Due to scale, wax and forming of hydrates, it is often installed even deeper.

Installation depth of the TRSCSSV is also dependent of any kick-off point in the well. All the way down to the kick-off point is a potential collision zone if drilling a new well close to the existing well, and therefore the TRSCSSV must be placed below the kick-off point.

The regulations also require the TRSCSSV to be surfaced controlled, automatically operated, hydraulically operated and fail-safe closed. The maximum installation depth is calculated as shown below.

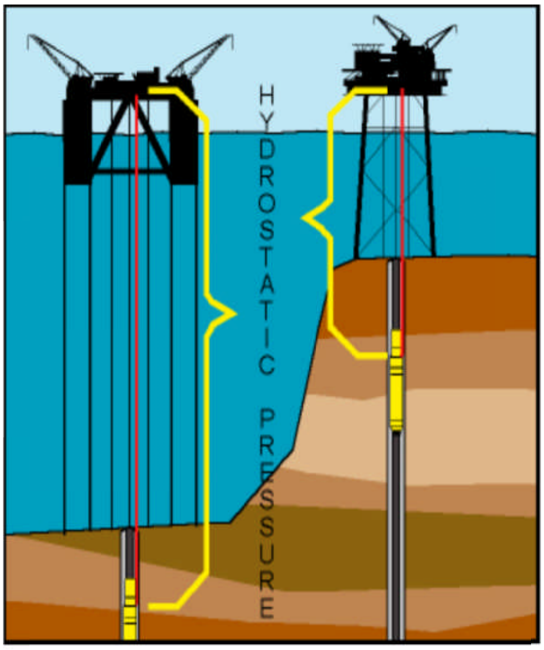

Figure 4-8- Illustrates hydrostatick pressure in control line [39]

The maximum installation depth of a TRSCSSV is decided based on the total hydrostatic pressure exposed to the TRSCSSV. This depth is referred to as the "fail safe setting depth" FSSD.

Calculation of the FSSD is carried out considering the worst case scenario. Considerations for this type of calculations would be the specific gravity of control line fluid, the specific gravity of sea water, the specific gravity of completion fluid/mud in the annulus and the spring force in the TRSCSSV. The worst case scenario is where the spring in the TRSCSSV, is exposed to a hydrostatic pressure created from the fluids mention above which creates the highest hydrostatic pressure. If the control line breaks, sea water or mud could influence the hydrostatic pressure at the TRSCSSV. If the TRSCSSV is exposed to a hydrostatic pressure in the control line, greater than the spring force, the flapper will not close.

Inside the TRSCSSV there is a spring which closes the valve. There is a piston connected to this spring, and this piston is again influenced by the hydrostatic pressure applied to the TRSCSSV.

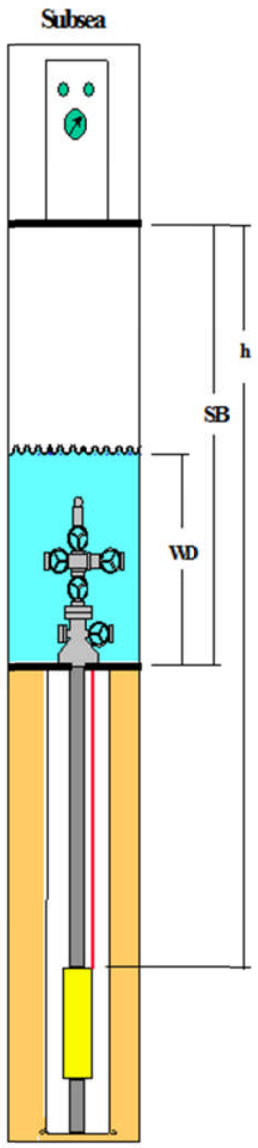

Figure 4-9- Illustrates hydrostatic pressure in sub sea control line [39]

Hydraulic oil: 0,89sg
Saltwater: 1,03sg

Hydrostatic pressure:

$$Hydrostatic\ pressure = \rho * g * h \qquad 4.1$$

$\rho = Specific\ gravity$ off fluid
$g = Gravitational\ constant$
$h = height\ of\ fluid\ collum$

$$\sum Forces = Hydrostatic\ pressure + W + Ff - Fs = 0 \qquad 4.2$$

$$\sum Forces = (Sd * g * \rho) + W + Ff - Fs = 0 \qquad 4.3$$

$$Sd = \frac{Fs - W - Ff}{(\rho * g * A * SF)} \qquad 4.4$$

$$Sd(ft) = \frac{(231\ -15-20)lbs}{(1{,}03*0{,}0981)(\frac{bar}{m})*\frac{14{,}5(psi)}{3{,}281(ft)}*(\frac{0{,}475^2}{4}*\pi)(in^2)*1{,}15)} \qquad 4.5$$

$$Sd = 2153{,}8\,ft = 656{,}4m$$

$Sd = Setting\ depth$
$Fs = Spring\ force$
$Ff = Friction$
$W = Weight\ of\ moving\ parts$
$A = Area\ of\ piston$
$SF = Safety\ Factor$

Example values for an TRSCSSV:
$Fs = 211\ lbs$
$Ff = 20\ lbs$
$W = 15\ lbs$
$Piston\ diameter = 0{,}475\ inch$

The setting depth based on saltwater in the control line is 656,4m.

After the TRSCSSV is installed, there are government requirements of pressure testing. The valve must be tested with both high and low differential pressure in the flow direction. Maximum pressure for the low pressure test is 7MPa.

After the TRSCSSV is installed and the well is handed over to production, there are requirements to monitor of the TRSCSSV. The valve shall be leak tested at specified regular intervals. Duration of these tests shall be 30 minutes, and tests must be conducted on a monthly basis until three tests have been approved.

After the three tests, the valve must be tested every three months until three tests have been approved. After these tests have been performed, it is necessary to test the TRSCSSV every six months.

The requirements to be fulfilled to pass the test are: leak rate for gas is maximum 0, 42 Sm^3/min, leak rate for fluid is maximum0, 4 l/min. It could be difficult to measure the leak rate directly, and in this case it is allowable to use pressure monitoring of an enclosed volume to observe for leaks.

4.2.4 Gas Lift Mandrel [4] [5] [9] [40] [41] [42] [43]

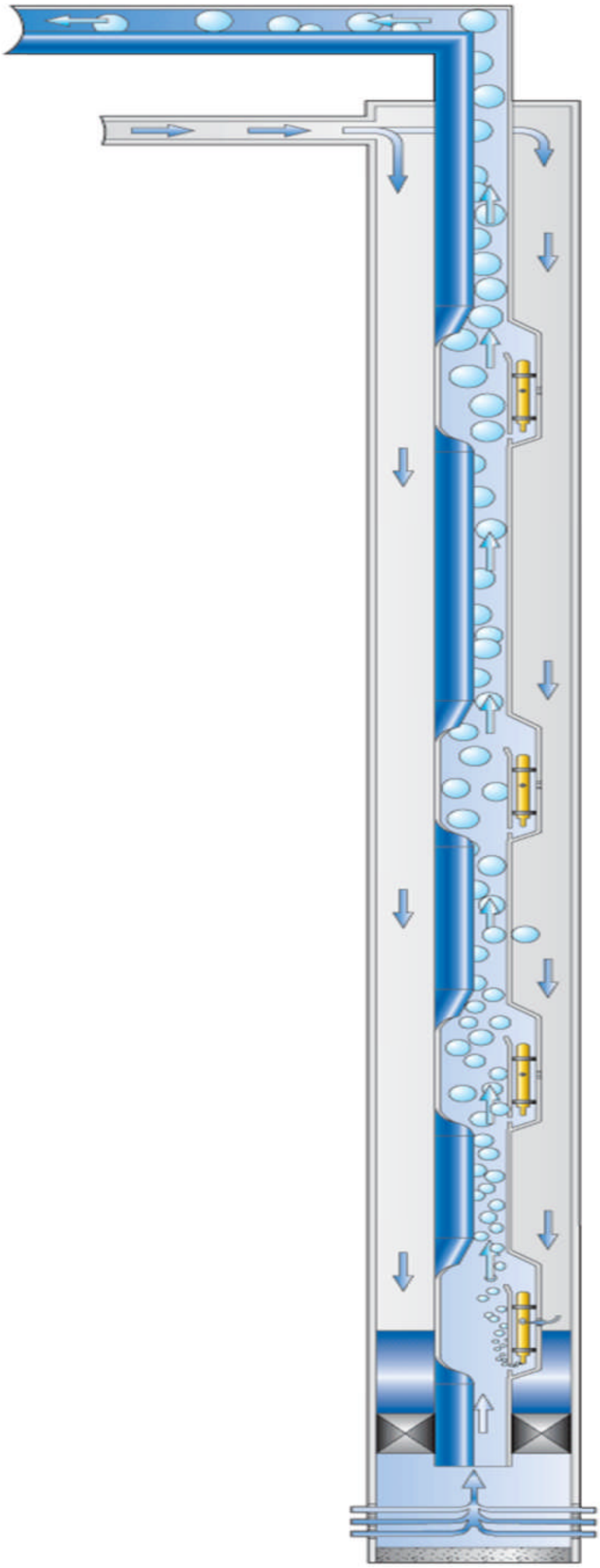

Figure 4-10- Gas lift system [40]

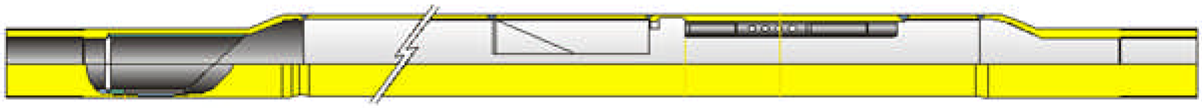

Figure 4-11- Side pocket mandrel [40]

Gas lift is a method of artificial lift, where gas is pumped down annulus. The gas will follow the annulus downwards and enter through a side pocked mandrel (SPM). Inside the SPM there is installed a gas lift valve (GLV), which purpose is to allow gas to enter the production tubing from annulus, and to make sure that no reservoir fluids is getting in to the annulus.

After the gas has passed through the GLV, it is inside the production tubing. Here the gas will be mixed together with the well stream. This would leave the well stream with a lower specific gravity, which would make the well stream flow to the surface. There could be several reasons for needing to use gas lift, some wells need to have a continuous gas lift, and some only need to be "started" using gas lift.

Continuous gas lift is used if the specific gravity of the reservoir fluid is greater than what the weight that the reservoir pressure is capable of lifting by natural pressure to the surface, or if the production rate would increase by such an amount that it would be an economical benefit to use gas lift.

Starting or "unloading" the well is a method used to displace the annulus for fluids. Normally the annulus is filled with completion fluids after installation of the production tubing. Displacing of these fluids to gas is achieved through what is called an unloading process, which usually requires several SPM´s installed in the well. This is due to the injection pressure of the gas, it is often too low to displace the entire column of fluid through one single SPM.

Figure 4-12- Orientating groove inside SPM [41]

Figure 4-13- Pocket for GLV [41]

The SPM are equipped with a valve, there are several types of valves that can be used inside the SPM.

Injection pressure operated gas lift valve

Injection operated gas lift valves are activated by the gas injected down the annulus. To open the gas lift valve, the pressure in the injected gas must be grate enough to over com the closing force of the bellow inside the gas lift valve.

Inside the injection pressure operated gas lift valve there is a piston, which opens and closes the valve. On top of the piston there is usually a bellow or a spring. The force acting on the piston from the bellow or the spring is what closes the valve. When the bellow or spring is exposed to a higher injection pressure than the tubing pressure, the valve will open.

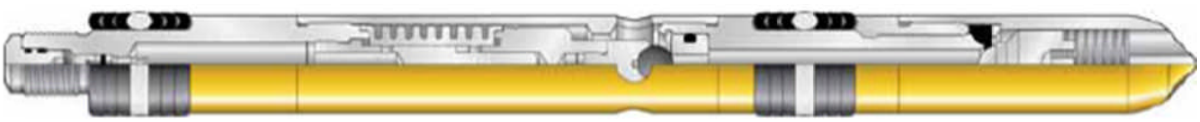

Figure 4-14- Injection pressure operated gas lift valve [42]

In figure 4-15, it is illustrated how the valve is functioning. Gas flowing down the annulus will enter the SPM and be led into the gas lift valve. When the gas has entered the gas lift valve, the gas will start to compress the bellow. When the bellow is compressed enough to allow gas to pass through the upper valve, it will push the lower ball down to its ball seat and further flow around the ball and into the production tubing.

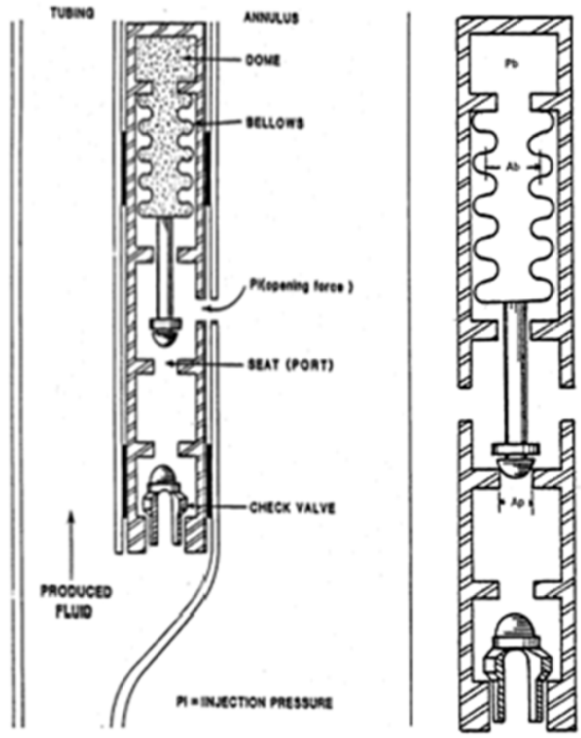

Figure 4-15- Illustrates a bellow injection pressure operated gas lift valve [43]

Production pressure operated gas lift valve

A production pressure operated gas lift valve, figure 4-16, is quite similar to an injection pressure operated gas lift valve. It consists of a piston and a bellow or a spring, which will keep the valve in closed position under normal circumstances. Produced fluids will enter the valve chamber and act upon the effective area of the bellow, which again will help opening the valve and allow gas to flow from the annulus and into the tubing.

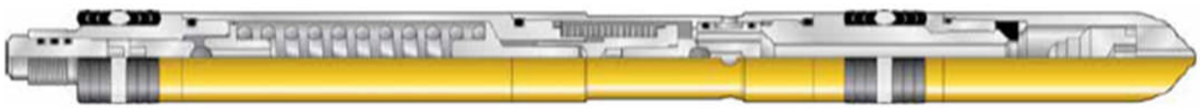

Figure 4-16- Production pressure operated gas lift valve [42]

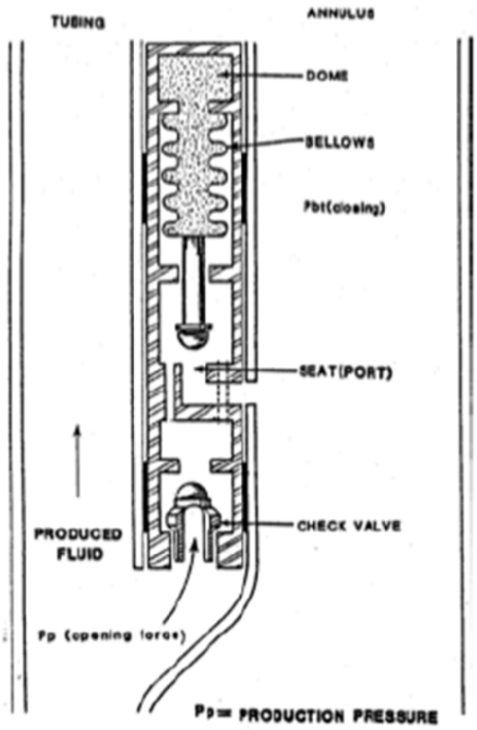

Figure 4-17- Illustrate a bellow production pressure operated gas lift valve [43]

Series orifice valve

Figure 4-18- Orifice gas lift valve [42]

An orifice valve is a valve with a fixed orifice, figure 4-18. Inside this valve there is a flapper or a spring connected to a ball, which is used to open and close the valve. The orifice valve is a one way valve, which only allows flow to pass through from annulus to tubing. Normally this type of valve is used as the lower valve in a series of gas lift valves, because this valve does not have to close the passage from annulus to tubing.

Dummy valve

Figure 4-19- Dummy gas lift valve [42]

The dummy valve, figure 4-19, is often used during installation of the completion. The dummy valve is made of solid steel and has no possibility of allowing gas or fluid to pass through. Pressure testing of the production packer from above could be a problem if there are installed gas lift valves in the SPM. The reason for this is that to perform a pressure test on the production packer from above it is necessary to pressurize the annulus. This is the same annulus as the injection gas will be pumped down later, and if the gas lift valves are set to open at a pre-determined pressure it would not be possible to pressure test the production packer from above.

Lock

To make sure the valve is locked to the SPM and stays in place during production, it needs to be secured inside the SPM. In figure 4-20, different types of locks, also called latches, are shown. As figure 4-20 illustrates, there are different ways to lock the GLV to the SPM. The RM-latch uses dogs, The RA-latch uses a ball and The RK-latch uses a ring to lock the GLV to the SPM. Installation and retrieving of the different latches are performed in the same manner, and usually the type of latch is decided based on the lock profile in the SPM.

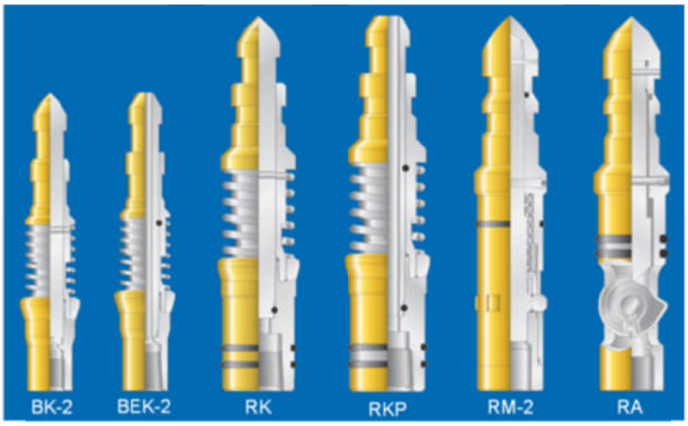

Figure 4-20- Locks used for gas lift valves [44]

4.2.5 Installation of gas lift valves [14]

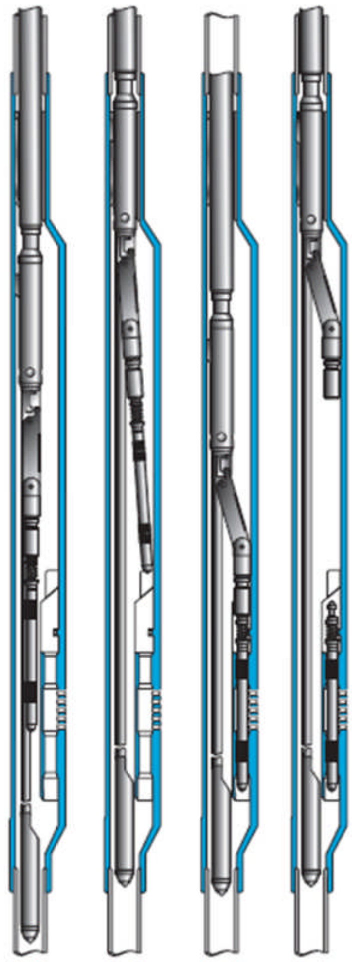

Figure 4-21- Illustrates the use of kick over tool [14]

The installation of gas lift valves is carried out using a wire line kick over tool (KOT). On the surface the GLV is made up to the kick over tool and the tool is run down the well. Activation of the tool is done after the tool has reached the SPM. The tool is run through the SPM, then pulled back through the SPM. As the KOT is pulled back through the SPM, the trigger located on the back of the KOT is orienting, and also activates the KOT. As the KOT is oriented and activated, and the arm is kicked out, the tool can be run down in to the SPM and the GLV will be installed.

After the GLV is placed in the pocket of the mandrel, the GLV will lock into the groove in the mandrel and the KOT can be sheared free and pulled back to surface. Pulling of a GLV is done in the same manner as the installation, but the running tool is then substituted with a pulling tool.

4.2.6 Chemical Injection Mandrel [5] [45] [46]

Figure 4-22- Scale in production tubing [45]

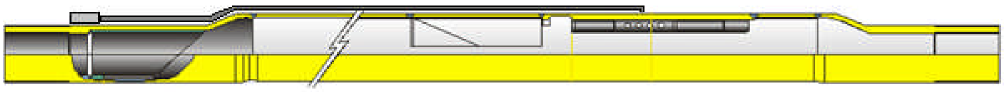

Figure 4-23- Chemical injection mandrel [46]

Scale as shown in figure 4-22, is a production problem in the North Sea. Scale can dramatically reduce the effective flow area, also in components as a TRSCSSV the flow of hydrocarbons is exposed to a reduction in pressure due to inner diameter reduction. Pressure changes can lead to forming of scale, which again can lead to failure of TRSCSSV and other components.

Oilfield scale mainly consists of inorganic salts with calcium carbonates, barium and strontium sulphates. Brine, formation water, can form scale if it is exposed to changes in pressure and temperature, or when two incompatible fluids are intermingled. Scale formed under these circumstances, tends to be carbonate scale. While scale formed by formation water rich in calcium, strontium and barium mixed with seawater high in sulphate tends to produce a sulphate scale.

To avoid scale production in a production tubing is very difficult, but with the use of a Chemical injection mandrel (CIM) it is possible to inject scale dissolvent/preventing chemicals to reach the production tubing. A CIM is usually installed close to the production packer, to get it as deep as possible to allow the injected chemicals to follow the production flow for as far a stretch as possible.

A chemical injection mandrel is usually designed as a SPM, with a connection point in top of the mandrel which allows for connection of a separate control line for injection of the chemicals. The control line connection point is made in such a way that the injection of any fluids into this tube will be lead down to the bottom of the CIM and go through the installed valve inside the CIM. The typically used control line for injection is 3/8 inch.
Otherwise the CIM is as a SPM, designed so that the same tools used for installing and retrieving valves inside the CIM are the same as for a SPM.

Figure 4-24- Chemical injection valve [42]

4.2.7 Splice sub [9] [25] [26]

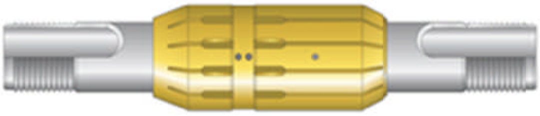

Figure 4-25- Splice sub [26]

A splice sub is used above and below assemblies with pre-installed control lines. When there is a control line that needs to go through a production packer, there is usually a pre-installed control line feed through the packer.

To connect the control line to the one coming up from the well the lines needs to be connected to each other "spliced". This splice operation is time consuming and must often be carried out on the drill floor. It is of interest to minimize the time used on drill floor to reduce the cost. Therefore it is common to install a splice sub where the control lines are intended to be spliced, make up half the splice onshore, and secure the pre-made splice in to the splice sub. When installing the completion offshore, the splice is completed, placed in a pre-fabricated slot in the splice sub and secured in the splice sub to prevent the splice to be damaged during the rest of the installation phase.

4.2.8 Production packer [5] [9] [7] [25] [47]

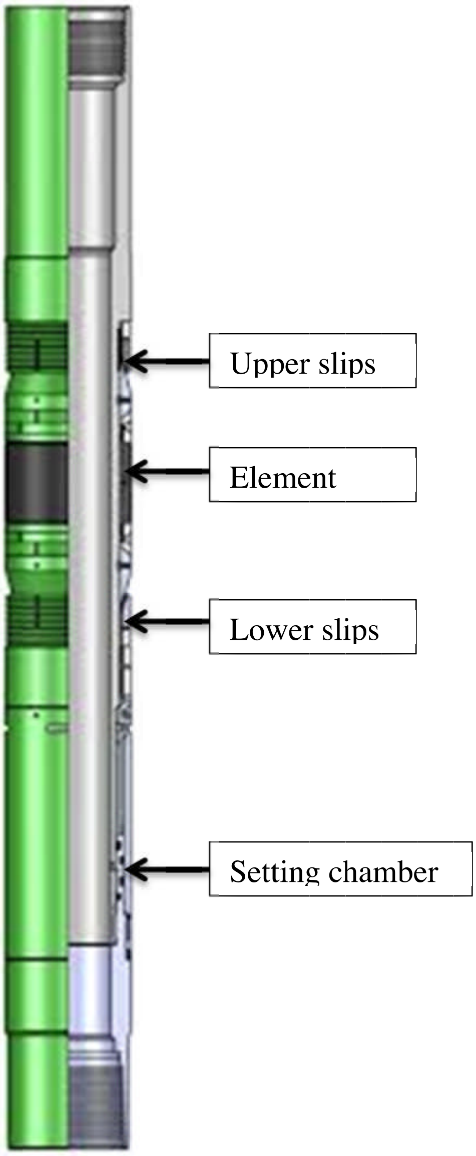

Figure 4-26- Production packer [47]

A production packer is installed in the well as a primary barrier, around the production tubing, to prevent reservoir fluid from being able to get from the reservoir to the annulus. Production packers are often a tubing installed packers, which means that the packer is run as a part of the completion string, as an integrated part of the production tubing.

The majority of production packers installed in the North Sea as a part of the completion, run above any liners, are mainly hydraulic set. Hydraulic set packers are assembled using moving parts held in place by shear screws.

When at setting depth of the packer, the well will be pressurized. Fluid from the well will enter in to the setting chamber and act on a piston. As the well pressure increases, the piston inside the setting chamber will move upwards and force upper slips to be pushed out against the casing. The element will be compressed, and the lower slips will then be pushed out against the casing. When the packer is set, it will be held in this position by a body lock ring. This ring is a ratcheting ring which slides upwards during setting of the packer and is then locked into a top position, keeping the slips and element in set position.

To be able to pressurize the well, the well cannot be open to the formations. If there is a screen liner or if the well has been perforated, it would be necessary to run a plug prior to pressurize the tubing to set the production packer. This plug is installed inside the production tubing below the production packer.

Together with zonal control, it is necessary to have production packers as zonal separators. When several production packers are installed together, it is important to have packers that do not move during the setting sequence. Movement of the packer could lead to stretch or buckling of the tubing.

Packers used for zonal isolation will also require a feed through feature for control lines, this would be control lines for pressure and temperature gauges, hydraulic sleeves or chemical injection. Figure 4-27 shows a packer with a feed through feature.

Figure 4-27- Production packer with control line feed through [48]

Production packers are divided in two categories, retrievable or permanent packers. Retrievable packers often need to be cut at a certain spot, the purpose of such a cut is to make the body lock ring loose it´s support and make it possible for the slips and the element to move again. When the cut is performed, either with a mechanical cutter or with a chemical cutter on wire line, the packer should come out in one piece.

Permanent packers are as the name indicates permanent, and can only be removed through milling. This is a very time consuming process and is not always a success.

The production packer element are made of some kind of elastomer that has the ability to form a tight seal when the packer is set, and is strong enough to withstand the surrounding formation fluids and the different forces it is exposed to. Typical material used for these elements are nitrile, hydrogenated nitrile, viton and aflas. The choice of which elastomer to choose for the production packer is based on temperature, presence of H_2S, if it is run in oil based or brine fluid, pH, exposure time and CO_2 level.

Governmental requirements states that the production packer must form a seal between the tubing string and the casing/liner, to hinder formation fluids to enter the A-annulus, and hinder fluids above the production packer to get in to the reservoir.

The production packer must be a permanent packer, it cannot be possible to release the packer with any up or down movement, and the packer must be able to withstand all loads it can possibly be exposed to. It can however be a retrievable packer that requires mechanical intervention in order to be released, but there must not be any chance of accidentally activating the release mechanism.

Governmental requirements for Design, construction and selection regarding production packers state:

1. The production packer must as a minimum be pressure tested to V1 class, as per ISO 14310.
2. The production packer shall be permanently set (meaning that it shall not release by up or downwards forces), with ability to sustain all known loads.
3. The production packer might be retrievable by mechanical intervention, such features shall not be possible to accidentally activate.
4. Both the packer body and the seal element shall withstand all maximum expected design pressures. The design pressure is based on the highest of:
    - The pressure based on pressure testing of the tubing hanger seals
    - Reservoir pressure, formation fracture pressure or injection pressure without taken in to account that there is fluid in the annulus above the production packer.
    - Shut-in tubing pressure plus hydrostatic pressure of the fluid column in the annulus above the packer less the reservoir pressure.
    - Collapse pressure as a function of minimum tubing pressure (plugged perforations or low test separator) at the same time as a high operating annulus (maximum allowable pressure) pressure is present.
5. The production packer shall be qualification tested in accordance with recognized standard, which shall be conducted in unsupported, non-cemented, standard casing [7].

When the production packer is installed, it must be leak tested based on the maximum expected differential pressure in the flow direction. Alternatively it can be inflow tested or leak tested in the opposite direction of the flow direction, based on the maximum expected differential pressure.

4.2.9 Down Hole Pressure and Temperature Mandrel with triple gauges [5] [11] [18] [29] [30] [31]

Figure 4-28- Gauge carrier mandrel [32]

To be able to monitor pressure and temperature in a well on a continuous basis, the well needs to have a gauge carrier mandrel installed together with the tubing. The gauge can typically provide measurements of pressure and temperature in the tubing and annulus and outside the production tubing. There also exist gauges which can provide measurements of density of fluids together with flow characteristics.

Installation of this gauge carrier mandrel allows for the gauge itself to be installed. There are several options to choose from regarding gauge solutions. The most common solution is to have two gauges, one that reads the pressure in the production tubing and one that reads the pressure in the annulus. Multiple gauges can be installed in one gauge carrier, and the gauge carrier is could be designed to carry three gauges. This means that there is one gauge to read the pressure and temperature in the tubing, one gauge that reads the pressure and temperature in the annulus, and there is one gauge which can be fitted with a “snorkel”.

When a snorkel is used, the gauge body is fitted to the gauge carrier, while the pressure and temperature sensor is mounted further up or down the well. Signals from the gauge are brought to the surface through a control line, which contains either a single conductor, a twisted pair of conductors or fibre optics.

Electronic gauges are quartz crystals, sapphire crystals or strain gauges. The quartz crystal provide the most accurate readings for pressure, typically ± 0,02% of full range and a typical resolution of ± 0,01 psi. Temperature accuracy is, however, not quite as accurate.
The gauge housing consists of three main parts: the sensor, the transducer and the converter, as illustrated in figure 4-29.

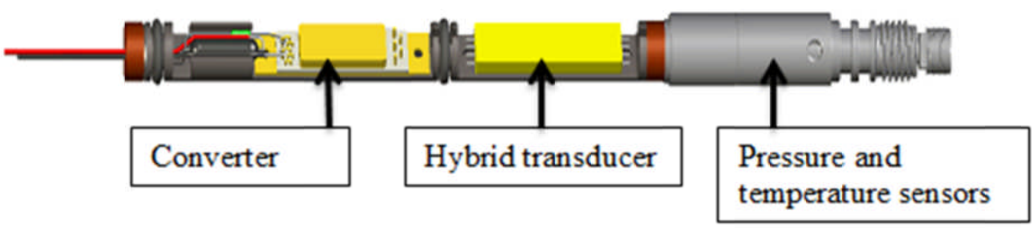

Figure 4-29- Illustrates the inside of the gauge housing [29]

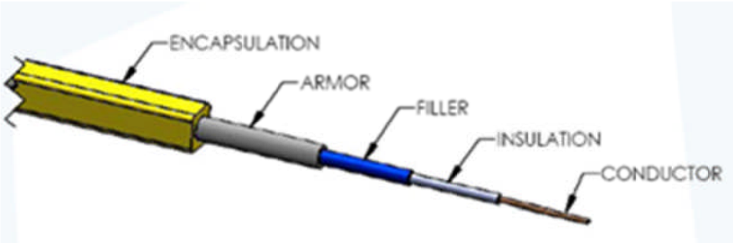

Figure 4-30- Electrical control line [30]

When the pressure and temperature sensors make a measurement, a signal is sent to the hybrid transducer. The signal from the hybrid transducer needs to be sent to a converter, which makes the signal readable for the surface equipment.

The sensors only need a minimal amount of power to be able to read pressure and temperature, and the power is provided from the quarts technology. Therefore, only milliamperes of electrical power need to be sent down to the gauges. Usually it is common to run the completion string while logging the pressure and temperature, as this is reducing the potential risk of sparks if a control line should be destroyed during installation.

Fibre optic

Fibre optic gauges often use Bragg gratings. The gratings reflect a proportion of the transmitted light back along the cable. Due to temperature differences when producing the fibre optical cable and the temperature down in the well, the grating will be affected by strain. The fibre optical cable is also exposed to pressure, which could also affect strain to the grating. This stain could change the frequency of the reflected wave.

Fibre optic cables also need some sort of screening to prevent hydrogen darkening, typically a sheath of aluminium is inherent in the encapsulation surrounding the cable.

Fibre optic gauges can be used to read pressure and temperature from one single point in the well, as with electrical gauges. Figure 4-31, show the single point gauge. The fibre optical cable used for single point pressure and temperature gauges is called a single mode cable, and has a fibre diameter of typically 8,3 μm. Only one path of light is allowed to travel through this fibre, and when the diameter is so small the transmission speed will increase. Figure 4-34 illustrate a typical single mode cable. A single mode signal consists geometric of only one mode, not only one frequency.

The greatest advantage with fibre optical cable is that it can be used as distributed temperature sensors (DTS). When using DTS, it is the fibre itself that is the sensor, and this allows for temperature readings through the entire length of the fibre optical cable. The diameter of the fibre´s in this cable is 50 μm, and when the fibre is this large, it allows for multiple paths of light traveling through the fibre. This makes it possible to read the temperature along the fibre cable. Figure 4-35 illustrate a multimode fibre cable.

As a fibre optical cable designed to read pressure and temperature at separate points don't have the possibility to read the temperature along the cable as a DTS cable. Because of this, it is a common solution to run single mode and multimode fibre cables in one control line.

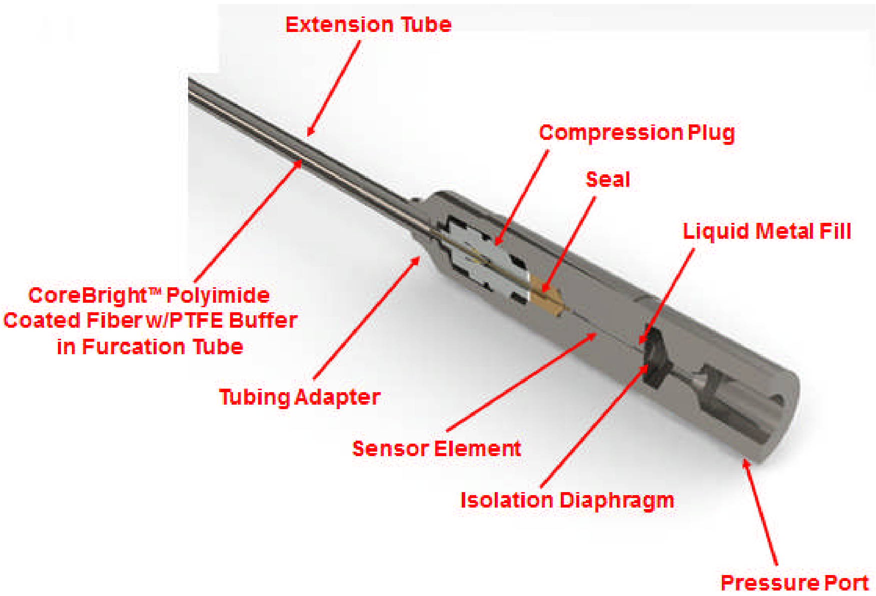

Figure 4-31- Fibre optical gauge [30]

Figure 4-32- Illustrates measurement with single sensor [30]

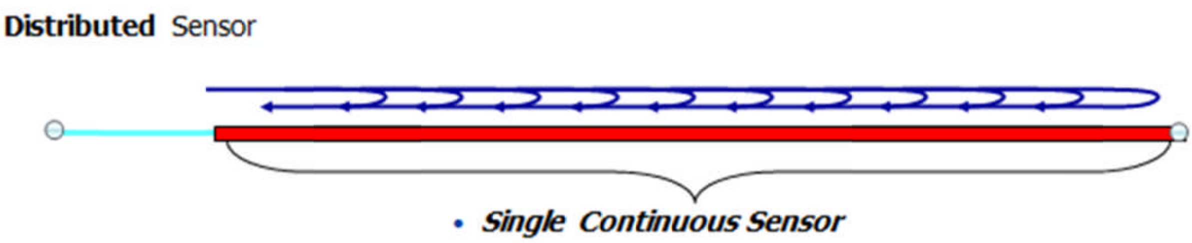

Figure 4-33- Illustrates measurement with single continuous sensor [30]

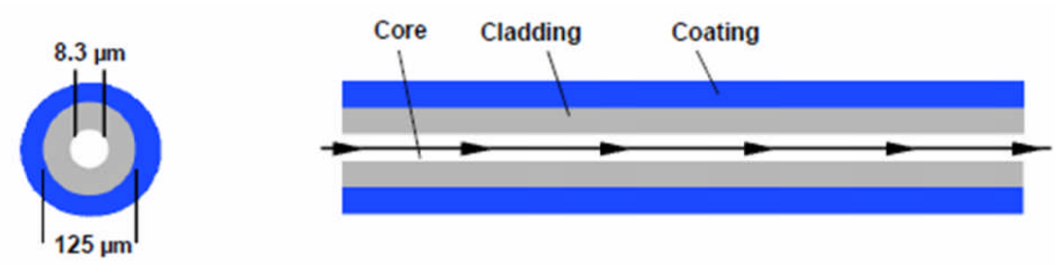

Figure 4-34- Fibre optical cable for single sensor [29]

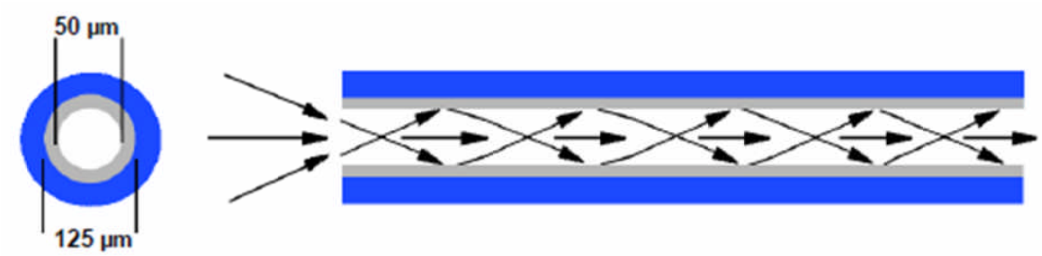

Figure 4-35- Fibre optical cable for distributed temperature sensor [29]

Figure 4-36, illustrates the Bragg grating. Light with a specified spectrum is sent through the fibre optical cable, a small part of the light spectrum will not be received on the surface. What part of the light spectrum that is missing, depend of the distance between the Bragg grating. The distance between the Bragg gratings will change due to pressure and temperature, different spectrums of the light will be reflected with different grating length. This "missing" part of light is then used to decide the temperature.

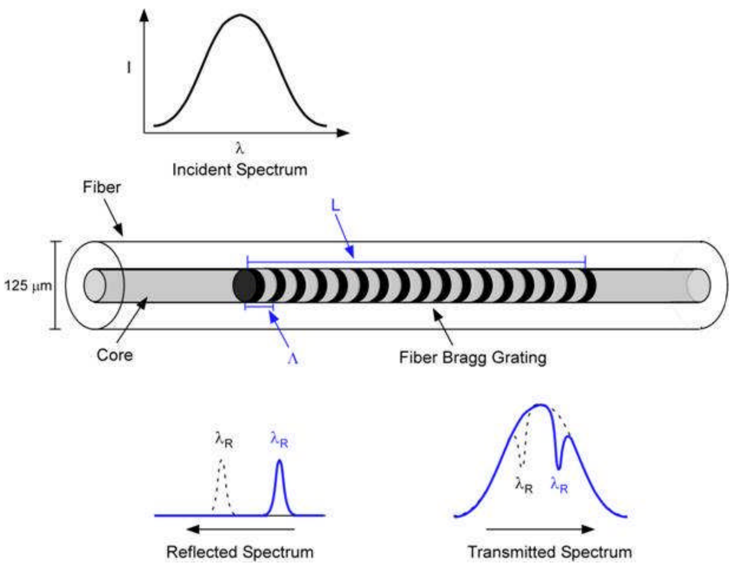

Figure 4-36- Illustrates the effect of Bragg grating [30]

Pressure and temperature monitoring during production is used to optimize the production of hydrocarbons. Gauge readings can contribute to make a flow characteristic of the well stream.

Wells with several zones usually have a gauge in each zone, which allows for zonal production control. When water breaks through a zone and the well is producing water, it will be possible to detect this using the surface logging system, and the sleeve in the zone that produces water can be closed or choked to reduce production from this zone. Monitoring the well production over time also provides information about the sleeve position each sleeve should be set in, to reduce water production.

Multiphase flowmeter

A multiphase flowmeter is a device that can be installed in the well together with the gauge or as a separate component in the completion string. With a permanent installed multiphase flowmeter, real-time data is provided to the surface using fibre optical cable.

Information provided from a multiphase flowmeter is used to optimize production. Especially with IWS completions with several zones, this is very useful information when setting the production choke openings. With the data from the multiphase flow meter and the ability to operate the different chokes in each zone, it is possible to collect information about zonal drawdown and productivity index. Combining the information from the data and ability to choke the production from each zone individually, optimization of the production can be achieved.

An optical multiphase flowmeter is based on speed of sound measurement and flow-velocity measurement, using the fact that the speed of sound is proportional to volume fraction of oil, gas and water in the well stream [18]. The flowmeter contains no moving parts, and uses only optical measures.

There are several benefits achieved by using a down hole multiphase flowmeter.
As measurements can be done down hole, the need for surface equipment as a test separator is not required. When producing from a multi-zone completion, data provided from the downhole flowmeter can be used to regulate production from each of the zones to get an optimal production. Well stimulation could be further optimized with detailed zonal information.
Installed flowmeters in the horizontal part of a well can be used to determine abnormal production, water break through or gas break through.

4.2.10 Crossover TN Blue threads [5] [49]

Figure 4-37- Tubing X-over [49]

The X-over used in this well is primarily used to change threads from 3 ½" threads to 5 ½". The reason for using 3 ½" tubing below X-over is due to the fact that the outer diameter of the hydraulic HCM-A sliding sleeve and Shroud adjustable hydraulic sliding sleeve, are sufficiently small to fit in the internal diameter inside the 9 5/8" casing. If 5 ½" sliding sleeves were used, the outer diameter would be grater then the internal diameter of the casing.

4.2.11 Hydraulic Controlled Sliding sleeve [9] [25] [26] [28] [35]

Figure 4-38- Hydraulic controlled sliding sleeve [26]

The HCM-A hydraulic controlled down hole sliding sleeve, figure 4-38, is a surface controlled sleeve which controls the production in the zone it is installed in. The HCM-A is an adjustable sleeve which allows for different choke positions and it can therefore control the flow of reservoir fluids. The mechanism that alternates the positions for the sleeve is made in such a way that there are up to 14 possible positions in one sleeve. Percentage of opening in each of the 14 steps is usually designed for each well.
Percentage of opening ranges from 0-100 %, and 100 % open is then set to a flowing area is the same as the flowing area inside the production tubing.

When installation of a hydraulic controlled sliding sleeve is performed, there are two control lines connected to the sleeve. The purpose off the control lines is to operate the sleeve. This sleeve is operated by hydraulics and is surface controlled. Of the two control lines installed, one is "opening" line and the other is "closing" line. Inside the sleeve there is a hydraulic chamber and inside this chamber there is a piston. The piston is "balanced", which means that the area of the piston is equal on both sides of the piston. The reason for the piston being balanced, is that the sleeve needs to be pressurised on both control lines during production.

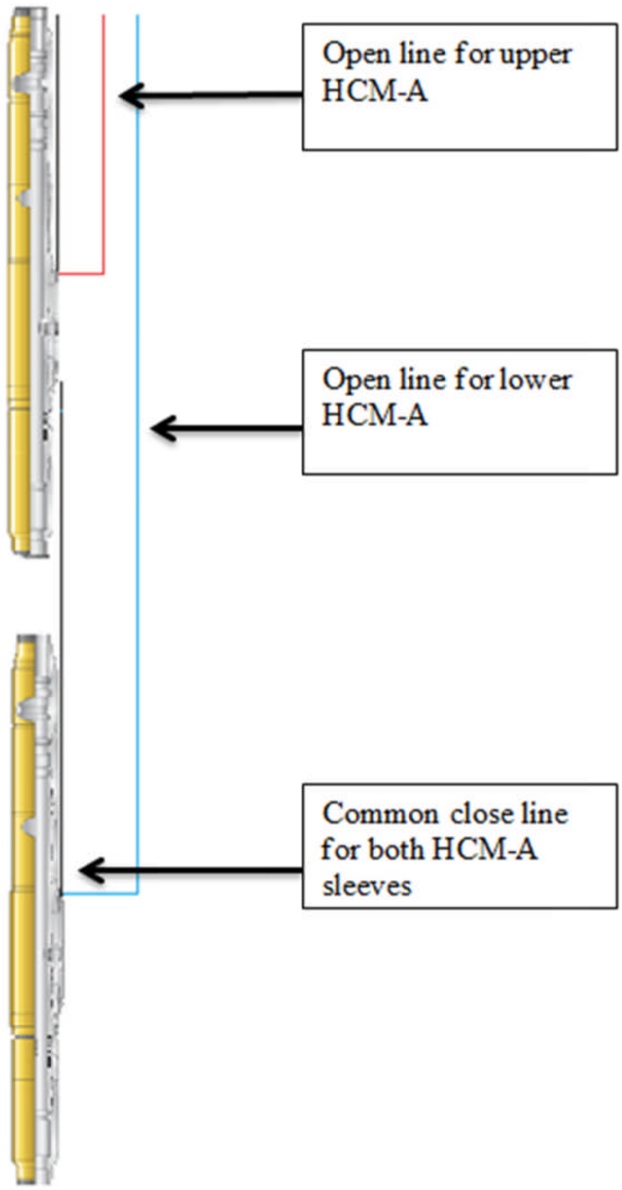

Figure 4-39- Control line configuration for common close [26]

Figure 4-39 illustrates how the control lines for the two HCM-A sleeves are connected. There is one "opening" line to each of the sleeves, and a common "close" control line. To change positions on these sleeves, one needs to bleed of the common "close" control line, and then pressure up on the "opening" control line. After pressurising the opening control line, Pressure must then be bleed down on the opening line. The closing line then needs to be pressurized before the opening line must be pressurized again to lock the sleeve in the current position.

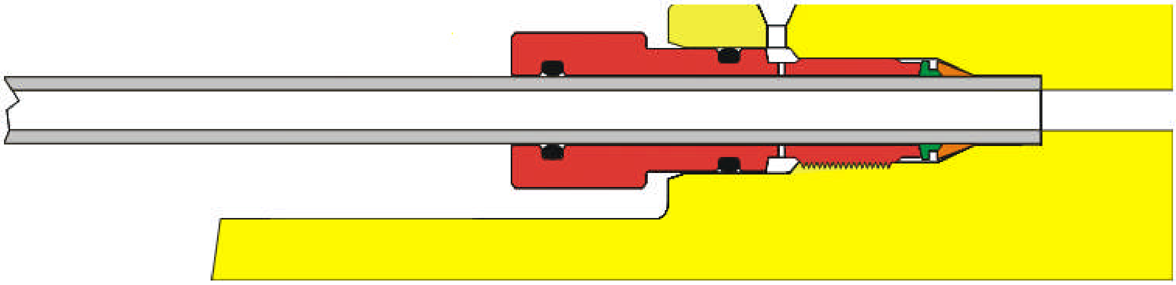

Figure 4-40- Testable control line connection [27]

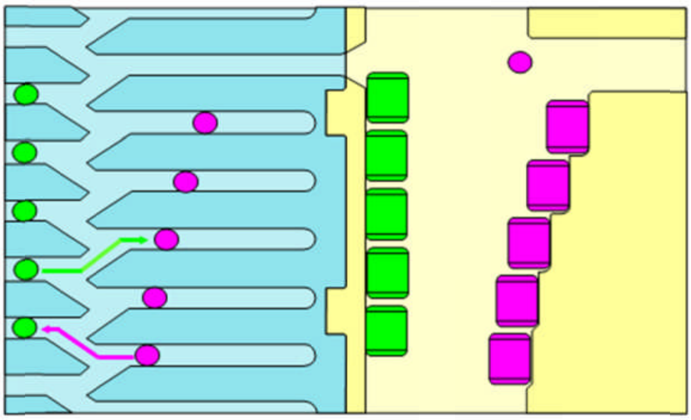

Figure 4-41- J-slot system [27]

Figure 4-41, illustrates what is called a J-slot. This feature allows the sleeve to move between the 14 possible positions. The J-slot makes the inner hosing of the sleeve turn around to the next position during the shift of positions.

4.2.12 Shrouded Controlled Hydraulic Sliding sleeve [9] [25] [26] [27]

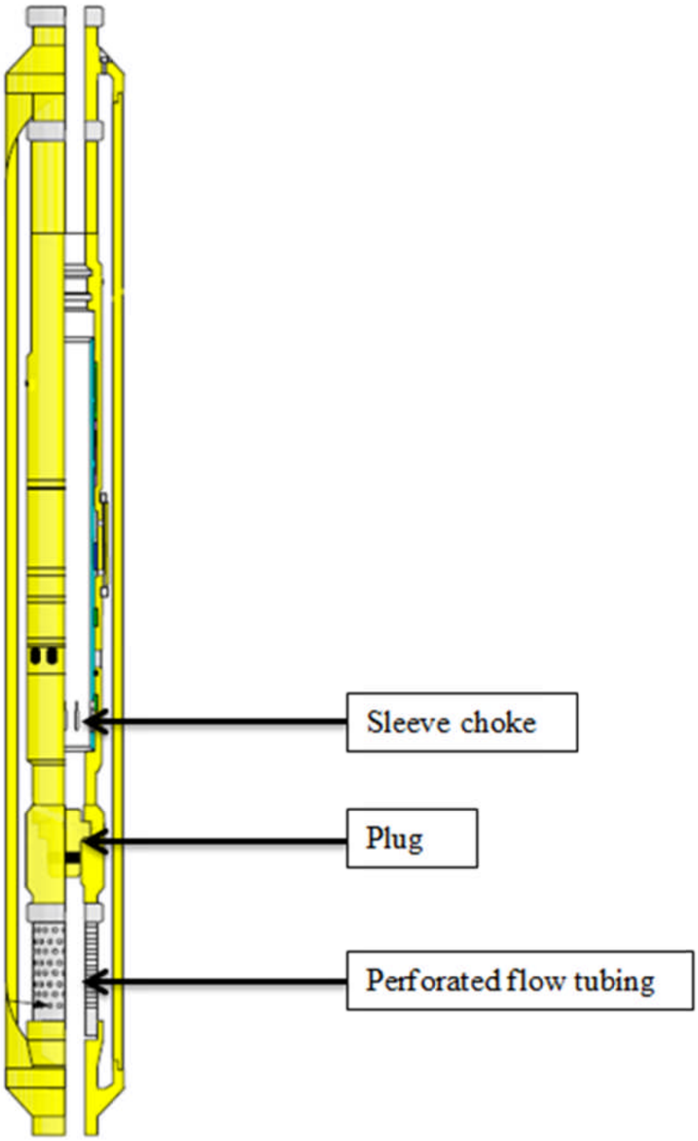

Figure 4-42- Shrouded hydraulic operated sliding sleeve [26]

The SHCM-A sleeve is used to choke the main bore well stream. As the well stream is flowing up through the tubing, it will get to the pre-installed plug in the SHCM-A. From this point, the well stream will be guided out through the perforated flow tubing and into a micro annulus. From the micro annulus it will be guided through the sleeve choke. Controlling well stream flow rate is only possible when guided through the choke of the sleeve.

Inside SHCM-A there is installed a plug, which is retrievable and is a backup solution if the sleeve should fail. If the sleeve should fail to operate, it is possible to go down with wire line or coiled tubing and mechanically operate the sleeve. One option is then to set the choke in the closed position and pull the plug installed inside the SHCM-A. After pulling the plug, the sleeve has no practical function and there is no way of controlling the well stream flowing from the reservoir.

Operation of SHCM-A sleeve is similar to the operation of the HCM-A sleeve described in chapter 4.2.11

4.2.13 Swivel joint fast connector [9] [50]

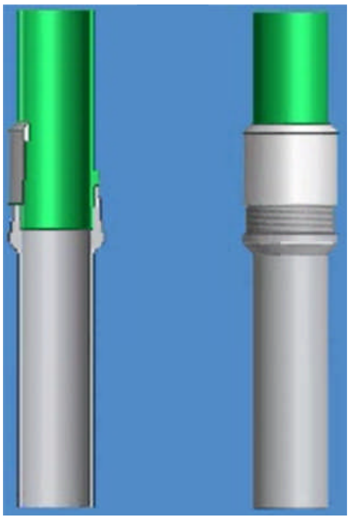

Figure 4-43- Swivel fast connector [50]

The Fast Swivel Joint is used for alignment purposes, and replaces the normal threaded connection. When installing the swivel joint in the completion, the control lines and upset diameters in the well can be aligned with the new assemblies made up in the completion. The assemblies will be delivered from shore with the premade swivel in both ends and will be interfaced and made up on the drill floor when the correct alignment between two assemblies is agreed upon.

The bottom part is only a metal pipe with male threads and the top part is made up of a metal seal and a bushing. The metal seal is fitted inside the bottom part, then the bushing is rotated downwards on the threads of the bottom part and the swivel assembly is ready.

Typically, this type of equipment is used when there is an assembly in the production tubing string, which cannot be turned around when being made-up to the tubing string. This type of problem typically occurs when there are production packers with control lines feed through the packer-body, it could be a problem to rotate an assembly that has fixed control lines connected in the top or at the bottom of the assembly. In these cases, it is necessary to use a swivel joint to be certain not to damage any of the control lines during the installation on drill floor.

4.2.14 Seal Assembly for Main bore PBR [9] [10] [35] [51]

Figure 4-44- Seal assembly [51]

In the bottom of the upper completion string there is usually a seal stem assembly. The purpose of this assembly is to provide a pressure tight connection between the lower completion, the multilateral completion and the upper completion. It also provides an entry point for later use of wire line and coil tubing to enter into the lower completion.

4.2.15 Control lines [9] [31] [39] [52] [53]

"Control line" is a term used for electrical, fiber optic and hydraulic lines. In an intelligent well solution all types of control lines could be used. With respect to the technology available today, it is not possible to install an intelligent well without the use of control lines. Operation of sleeves, down hole safety valves, chemical injection valves and readings from down hole pressure and temperature sensors all require control lines to operate.

Control lines used on sleeves and down hole safety valves are connected to a closed hydraulically system. With the sleeves installed several thousand meters below the sea bed, this requires a reliable system. Hydraulic oil that is being used to operate either a sleeve or a down hole safety valve, requires a certain set of properties regarding viscosity as a result of temperature changes. Particles in the hydraulic oil could lead to failure of the tool connected to the control line, therefore the hydraulic oil used in these systems are measured to be with a particle level below NAS-6. Water content is also measured, and must be below a predetermined level to prevent failure of the system. As this hydraulic system is a closed system and it is not possible to change the hydraulic oil after the well is installed, it is crucial that the oil used is clean and reliable.

Electrical control lines are produced to carry and protect a electrical conductor down to a pressure and temperature gauge, and then return signals to a surface logging system.

The material used for making control lines are usually 816 Inconel, this due to the environment that the control lines are installed in. Failure to a control line could lead to a recompletion, therefore the material used in the control lines needs to be suited for the installation environment. Outside of the control line there is a plastic protection. This protection is also preventing the metal itself to come in contact with the gas or fluid surrounding the control line, but it is impossible to prevent some of the gas or fluid to come in contact with the control line.

Control lines come in many different sizes and upsets. Hydraulic control lines to sleeves and down hole safety valves usually have an outer diameter of ¼". In control lines used for chemical injections, the outer diameter is typically 3/8". Control lines are fabricated as single lines, dual lines, tri-pack, four-pack and so on with every combination of type of control line that is required.

When installing a completion on a floating rig, movement of the rig could make the control line to be broken. If the control line is squeezed between to edges, due to the rig movement it could break. To reduce the possibility of the control line to break, a bumper wire is installed together with the control line. A bumper wire is a braided wire with an outer diameter that is a little bit larger than the control line. Figure 4-45 illustrates a sample of different combinations of control lines that could be produced.

Figure 4-45- Illustrates different configurations of control lines [39]

Control lines come from the manufacturer coiled on to drums, and these drums are fitted on to spooling units prior to running the completion. Figure 4-46 illustrates a basic set up for installing the control lines. Spooling unit with the control line drum mounted, the control line is routed through a sheave wheel and down in to the well.

As the control lines are being run along the tubing, they need to be secured and protected. Figure 4-48 shows a control line clamp. Control line clamps are installed on every tubing connection, and the clamp is fitted around the collar. Clamps are used to fasten the control lines to the tubing and secure the control lines from damage.

Figure 4-46- Illustrates control line installation [52]

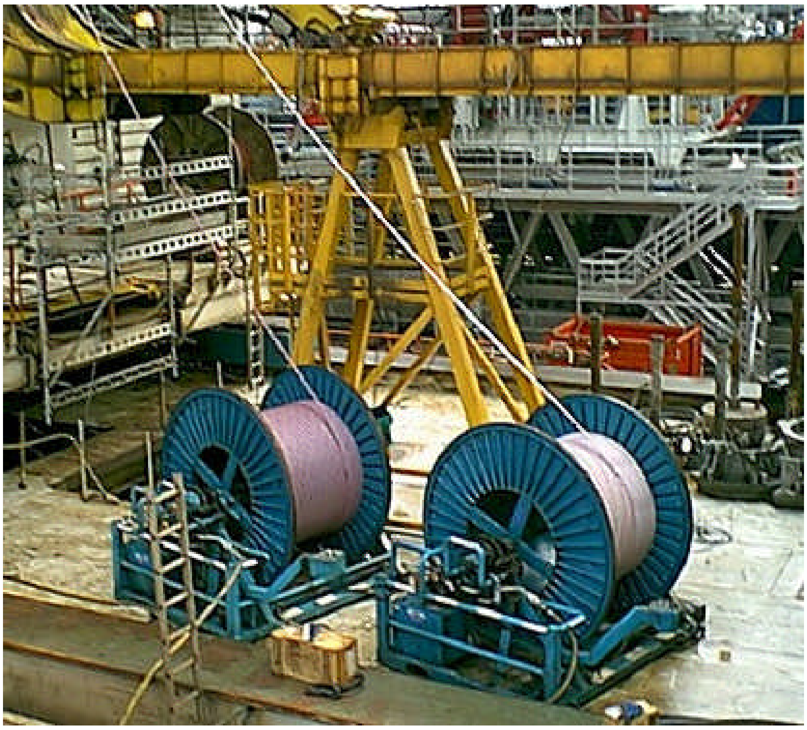

Figure 4-47- Control line rig up during instalation [31]

Figure 4-48- Control line protection clamp [53]

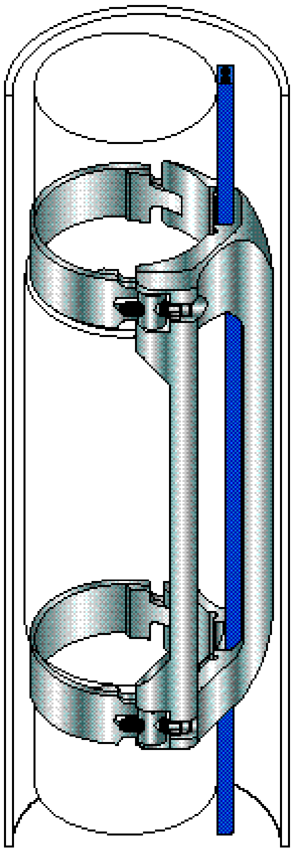

Figure 4-49- Illustrates control line protection clamp [31]

5 Lower completion

5.1.1 Main bore diverter [10] [19] [23] [24]

The main bore diverter is installed to secure access to the main bore or the lateral, only one of them is accessible for intervention operations. Two types of main bore diverters are available, either main bore access or lateral access. Flow from the main bore and the branch is also controlled by the main bore diverter.

Prior to running the upper completion, the main bore diverter needs to be installed. This is normally done onshore, and when the upper completion is installed, it is not possible to retrieve the main bore diverter.

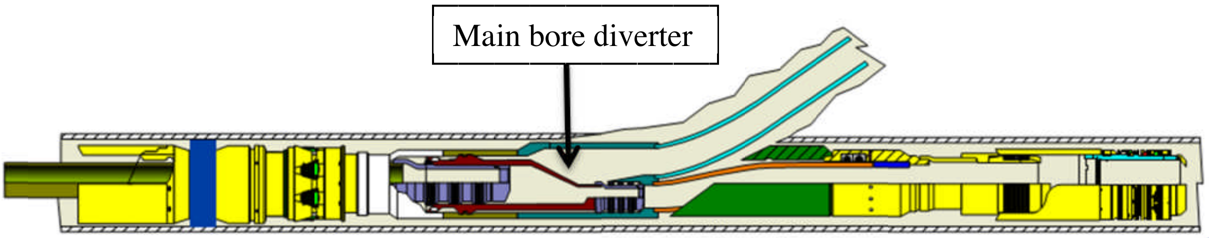

Figure 5-1- Main bore diverter [24]

As figure 5-1 illustrates the main bore diverter installed in the Hydrasplit junction. On this figure the main bore diverter is installed to allow access in the main bore.

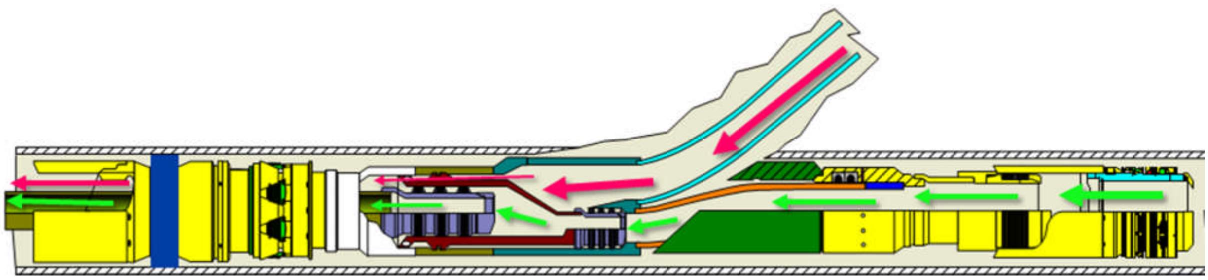

Figure 5-2- Illustrates well stream through junction [24]

As figure 5-2 illustrates, the main bore diverter is installed and the well has started to produce. The main bore diverter then guides the flow from the main bore into the tubing. Flow coming from the lateral is then guided around the outside of the main bore diverter and up the annulus to the hydraulic sleeve, where the flow is guided into the tubing.

5.1.2 Seal Bore Diverter with MLUT Production Anchor [10] [19] [23] [24]

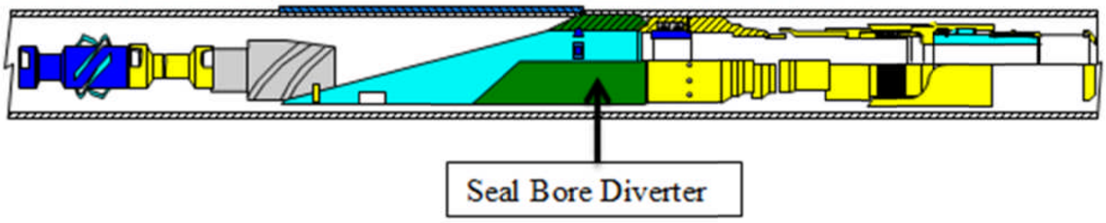

Figure 5-3- Seal bore diverter with whipstock [23]

To reduce tripping time when running drill pipe, the seal bore diverter is installed while running the whipstock. Installing the whipstock in the same run as the seal bore diverter reduces the number of drill pipe runs by one run, and running of the drill pipe is both a time consuming and a costly operation.

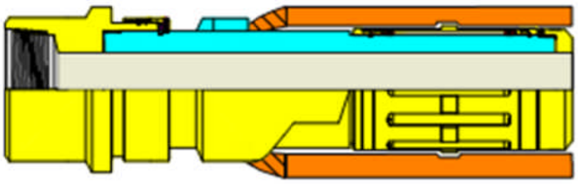

Figure 5-4- Production anchor [23]

5.1.3 MLZX Liner Hanger and packer with PBR [10] [19] [22] [23] [24]

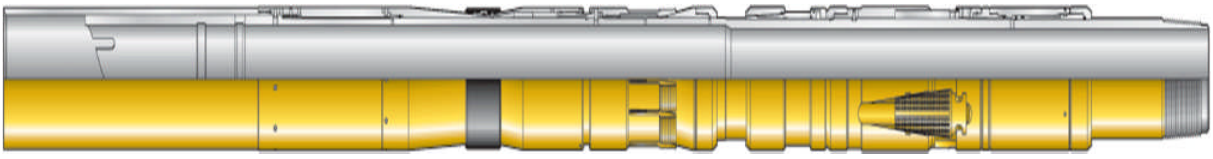

Figure 5-5- Liner hanger packer [24]

Figure 5-6- Orienting profile in liner hanger packer [23]

The MLZX liner hanger packer is the liner hanger used when running a multilateral liner solution. The purpose of this assembly is to hold the weight of the main bore liner, seal the annulus from the reservoir to the top well and offer a PBR (polish bore receptacle) that can be used to make a seal tight connection from the reservoir and into the production tubing.

This type of liner hanger is equipped with slips designed to hold the weight of the entire liner weight, and is also designed to prevent the entire liner from moving upwards after the packer element is set and is exposed to the reservoir pressure. The slips are also designed to withstand any rotational forces that may occur, for instance (30 000 ft-lbs rotational torque rating).

When the MLZX liner hanger and the main bore liner reaches the installation depth, the liner slips has to be set. To activate the setting mechanism of the liner hanger slips, the drill pipe is pressurized. Due to the running tool installed inside the liner, the pressure will be lead into a setting chamber and the setting piston will start to move. This piston movement will activate the slips, and they will grip on to the casing wall.

After the slips are set, the pressure in the drill pipe is bled off and the running tool is released from the liner hanger. The running tool is pulled up and then the packer setting dog sub, figure 5-7, is out of the liner hanger.

To set the liner hanger packer, you once again run down with the running tool, until the dogs on the packer setting dog sub is on top of the liner hanger. The weight is then laid down to activate the setting mechanism of the liner hanger packer element and the slips to hold the element in position.

The MLZX liner hanger also consists of a ML HR orienting profile. This profile is used to orientate the combined exit and seal bore diverter system. This ML HR profile is installed onshore in the work shop. After the liner is installed in the well, and the running string for the liner is pulled back to the surface, there will be performed a clean-up run.
Together with the clean-up string there will also be MWD. The MWD will measure the orientation of the ML HR sleeve. This measurement will be used to orientate the wipstock to the right position during the next run.

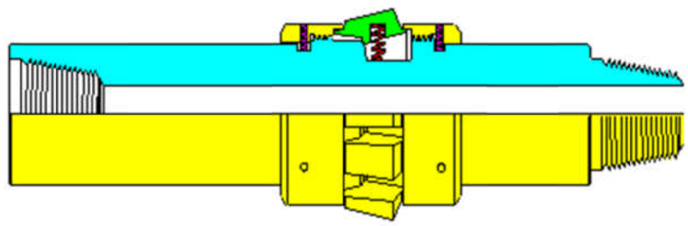

Figure 5-7- Packer setting dog sub [22]

5.1.4 Line Slot Wirewrapped Screens [3] [5] [16] [54] [55] [56]

Sand production leads to problems in sub-surface and surface production equipment, and therefore sand production must be kept at a bare minimum. Choosing the right sand control method is both time consuming and costly.

The process is started up by sampling reservoir sand. This could be done by sampling sand produced by other close wells in same reservoir, or bailed sand from this or other wells in same reservoir formations. Produced and bailed sand samples normally provide a poor set of data to be used for sand control planning. The reason for this is that bailed or produced sand is not representative for the actual size range of formation material, due to flow velocity and the carrying capacity of produced fluids. Better results can be achieved by sampling a core from the reservoir. Using the core to determine the particle size and distribution will provide a much better understanding of how the reservoir rock is composited.

Determination of particle size distribution is achieved by sieve analyze and a laser particle size (LPS) analysis. LPS analysis is used to determine the amount of fine particles in the sample due to the swelling and migration of bounding clays. Fine particles could also be a result of crushing during production.

The sieve analysis, also called gradation test, is used to determine the particle size distribution. The test is performed using a sample of reservoir rock. A mechanical shaker with a set of sieves with decreasing mesh size from top to bottom is used to perform the test. The reservoir rock is weighed and placed on top of the shaker. When the shaker is started, it will make the grains from the reservoir rock fall down through the sieves, and stop in the sieve with the mesh size small enough to contain the grain. After the test is conducted, every sieve is analyzed and average grain size on each sieve is determined.

Preventing sand to be produced can be accomplished in various ways, while fines always is produced it is important to keep the load bearing solids in place. Production of fines is usually good for the production, it helps cleaning the pore space.

Preventing sand production could be accomplished by production rate control, if the production rate is kept at a velocity low enough to prevent drag forces to break loose sand from the reservoir. The production rate control method is usually not the most economical method of preventing sand production.

Sand production can also be prevented using mechanical methods as slotted liners, screens, gravel pack or a combination of these methods. Design of sand control prevention methods have three main design parameters, optimum slotted liner or screen slot width, determination of optimum gravel size and distribution and effective placement technique. These solutions can be with or without gravel.

The slotted liner is the simplest type of screen, but in most cases slotted liners does not provide a sufficient reduction in sand production.

Wire wrapped screens are, to an extent, the most used sand production preventing solution used. Wire wrapped screens rely on sand arches forming naturally in the openings of the screen. If the formation contains fines, and these fines follow the well stream, it can lead to cutting of the screen and alter the flow.

Gravel packing is the next step of sand control, where gravel is spotted around the screens. Gravel could also be pressure pumped. Graded sand would then be placed outside the casing and into the formation. Gravel packing is performed to prevent any movement of formation sand.

Sand screens

San screens are simple constructions and the installation cost of standalone screens are reasonable low. Screens are mainly made of stainless steel, and are designed to prevent reservoir sand from entering the production tubing, leading to eroding of both down hole and surface equipment.

Standalone screens are installed inside the open hole section of the well, with no gravel pack present. Standalone screens come in different types, wire wrapped, pre packed, premium and expandable sand screens. Completion solutions with standalone screens typically consist of inflatable and/or swellable packers for zonal separation between each screen section. When designing a standalone screen solution, the screen strength and damage resistance, aperture size, plugging and erosion resistance, laboratory testing with formation sand samples and previous job experience need to be considered to choose the best suitable screen.

Wire wrapped screens can be designed for use in both horizontal and vertical completion solutions. A wire wrapped screen consists of a perforated inner pipe where longitucinal elements, rods, are welded along the inner pipe. Steel wire is either shrink fitted around the pipe or welded to every rod. Figure 5-8, show the rods and the steel wire welded to every rod. Figure 5-11, shows the shape of the steel wire, as shown it is "V" shaped.

Wire used on screens is usually made from 316L or 825 alloy, and the inner pipe is usually made with the same metallurgy as the tubing. Wire wrapped screens are typically used as standalone screens and in gravel pack solutions. Wire wrapped screens could also be made lighter, these are typically used in horizontal solutions.

Materials used to fabricate sand screens are high strength and corrosion resistant. The total flow area of the screen depends on slot width, screen length and wire thickness. Compared to a cased and perforated well inflow area, the screen usually has a greater inflow area, resulting in a lower fluid entrance velocity at the screen front.

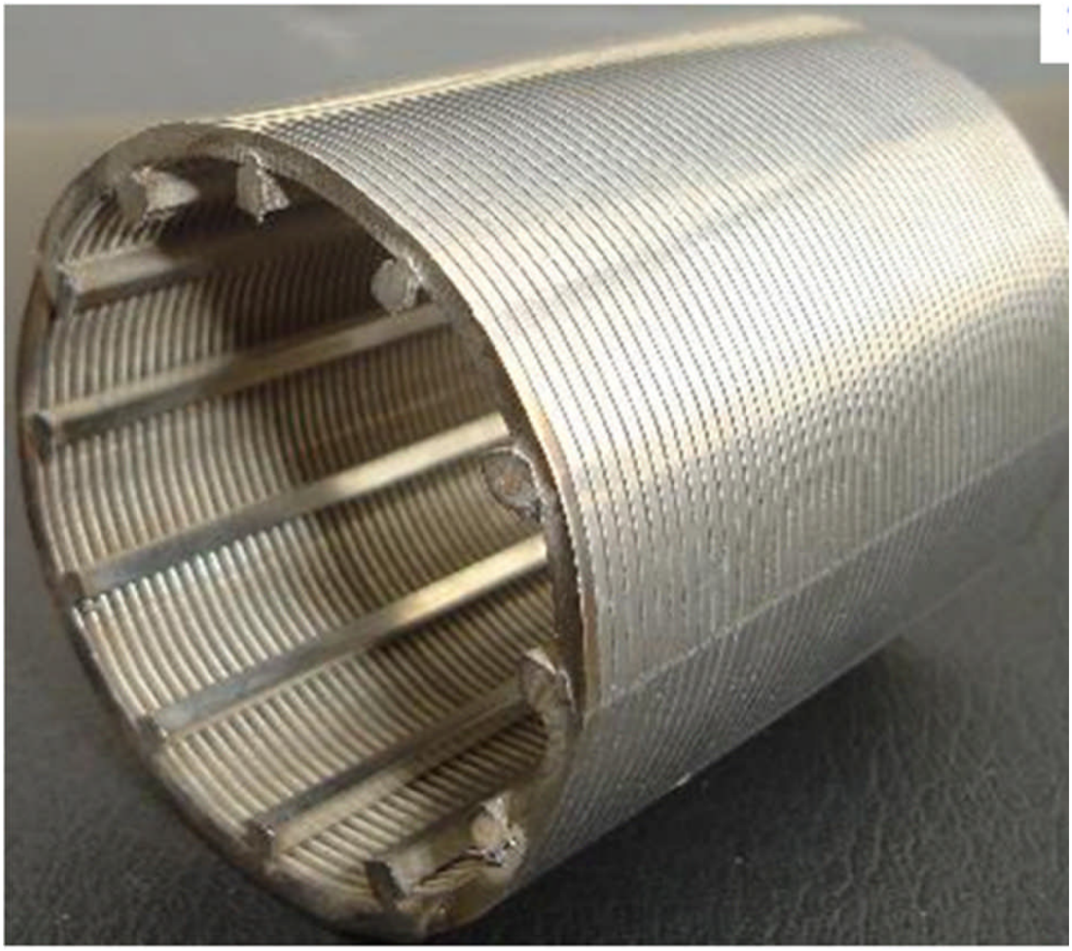

Figure 5-8- Outside screen jacket [54]

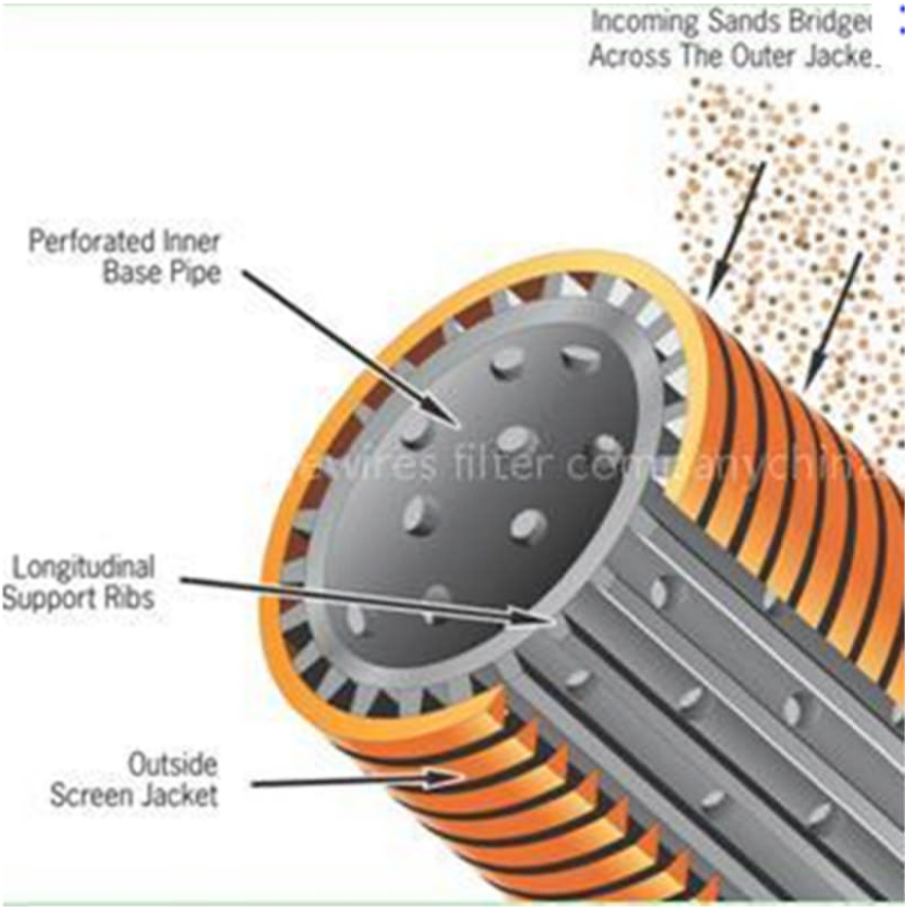

Figure 5-9- Illustrates sand screen layers [55]

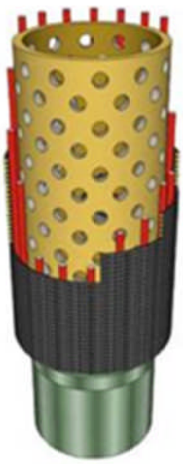
Figure 5-10- Illustrates parts of sand screen [3]

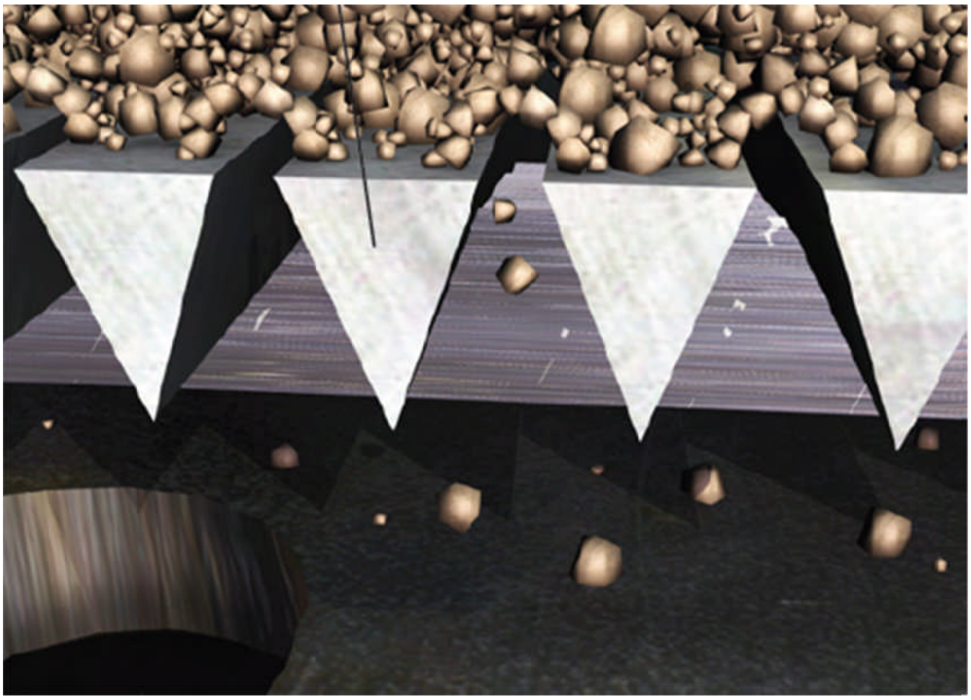

Figure 5-11- Illustrates how sand is prevented to flow through sand screen [16]

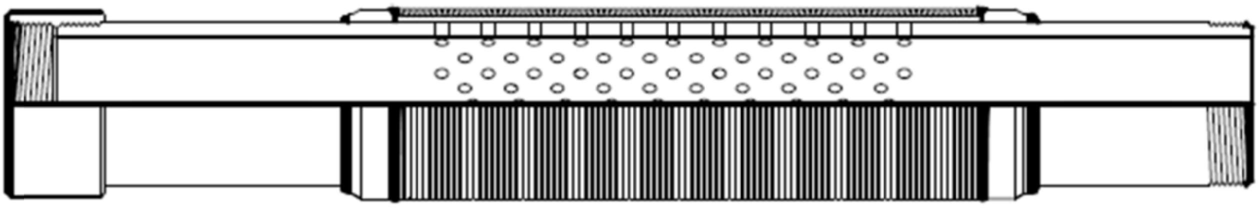

Figure 5-12- Illustrates a sand screen assembly [56]

5.1.5 Swellable Flow Constrictors [10] [31] [34]

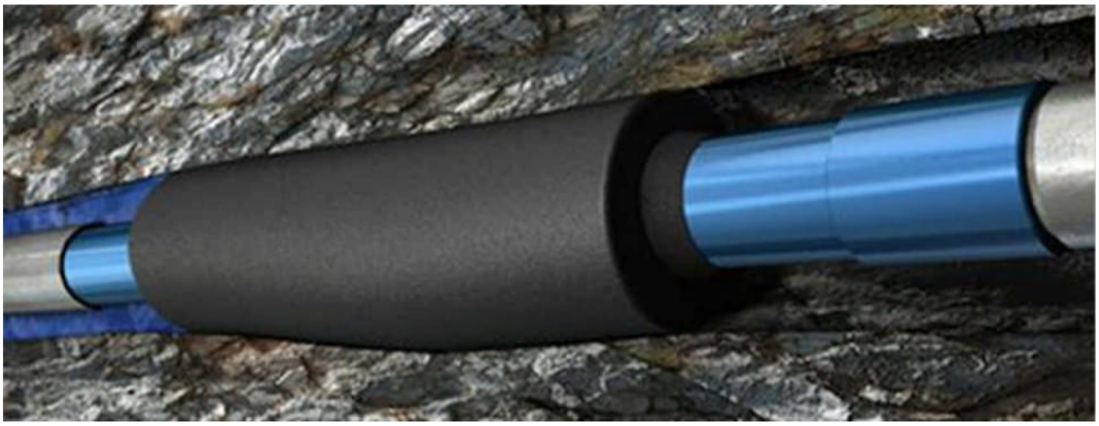

Figure 5-13- Swellable packer [34]

Figure 5-14- Swellable packer assembly [34]

Two types of swellable packer systems are available today, water swelling and oil swelling packers. Swellable packer systems rely on the packer element to swell due to the fluid it is exposed to. Swellable packers are suitable for both open and cased hole applications.

Swellable packers are made from a solid piece of pipe with the elastomer vulcanized to the outside of the pipe. The two end rings assembled to the packer holds the element in place and controls the direction of element swelling. To prevent the element from swelling prematurely, the packer is usually run in an inert fluid

Elastomers swelling when in contact with oil, is swelling due to the diffusion process. The rubber molecules absorb hydrocarbon molecules, and due to this absorption the elastomers will start to expand and seal off the intended area. Swelling of the elastomers occurs because of the special cross-linked polymer network which acts as a trap for the hydrocarbon molecules due to the natural affinity of the hydrocarbon molecules. This is a nonreversible process.

Elastomers swelling when in contact with water are swelling due to the process of osmosis. When the water enters the elastomer, the element will continue to swell until equilibrium is achieved. It is very important to consider the salinity level of both the fluid and the elastomer, as the osmosis process depends on it. Changes in the fluid properties and the downhole conditions could result in a reversion of the packer swelling.

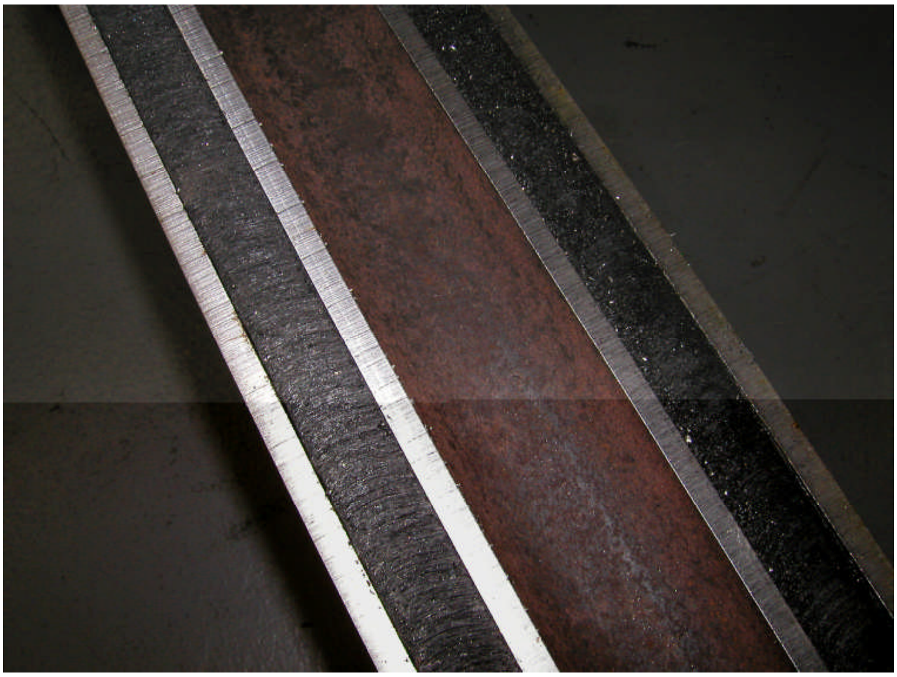

Figure 5-15- Cross-section of a swellable packer [31]

$$\%Swell = \frac{V_{Swollen} - V_{Inittial}}{V_{Inittial}} \qquad 5.1$$

$$\%Swell = \frac{ID_{Hole}^2 - OD_{Rubber}^2}{OD_{Rubber}^2 - OD_{Pipe}^2} \qquad 5.2$$

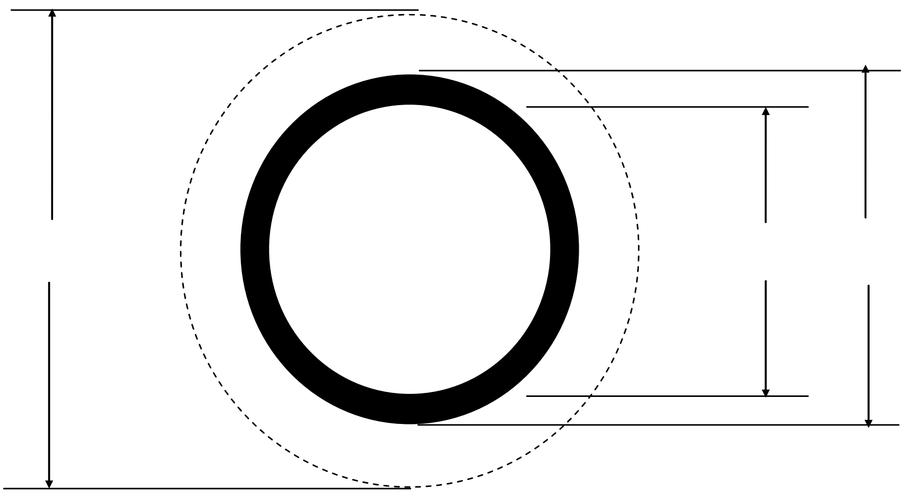

Figure 5-16- Measurements of swellable packer [31]

Performance		
Time to Swell:	4,85 d	
Time to Seal:	5,85 d	
Pressure Differential:	10 000,00 psi	
% Swell:	24,07 %	WARNING: Required Swell % should NOT exceed 105% Max Limit

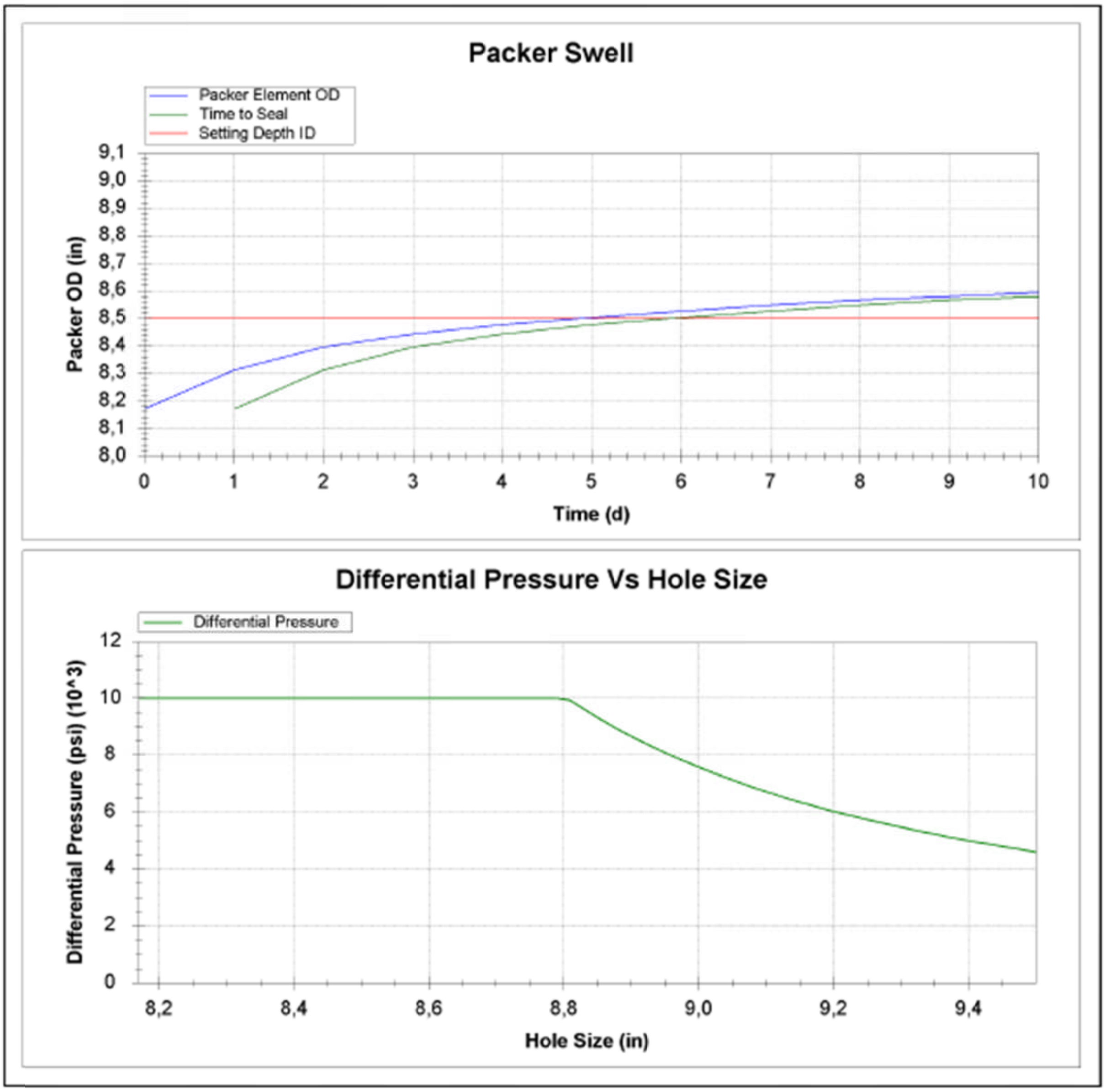

Figure 5-17- Simulation of swellable packer [57]

5.1.6 Reamer Shoe [10] [20]

Figure 5-18- Reamer shoe [20]

A reamer shoe is typically used in wells where the casing and liner running could be problematic due to cave-ins, clay swelling or poorly cleaned hole after drilling, this preventing the liner to reach designated depth. The reamer shoe is then capable of drilling out any cave-ins or other obstacles preventing the liner to reach its designated depth.

5.2 Lateral bore:

5.2.1 7" x 4" x 4" Hydrasplit ML junction [10] [23] [24]

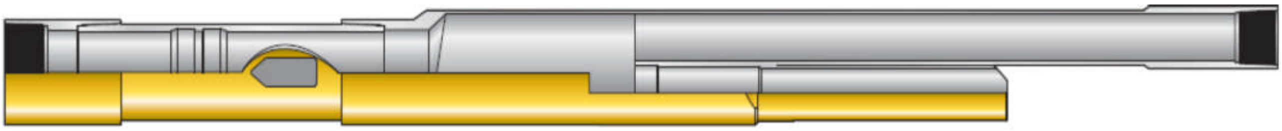

Figure 5-19- Multilateral junction [24]

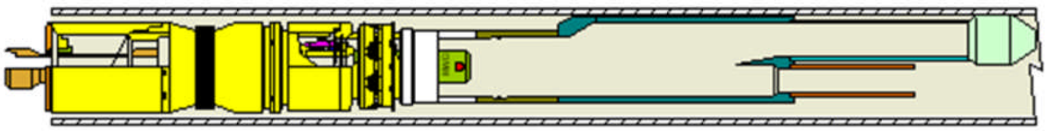

Figure 5-20- Multilateral junction with lateral and packer [24]

The Hydrasplit is a manufactured casing junction for multilateral solutions with a main bore and two branches.
The Hydrasplit ML junction is used to make a junction that is classed as a TAML level 5. The Hydrasplit junction provides a large liner size in the laterals, in this well it is 4 inch casing in both the main bore and the lateral. Installation of a main bore diverter, see chapter 5.1.1, allows for entering either the lateral or the main bore.

Installation of the Hydrasplit is performed after the main bore liner is installed, window is milled and the lateral is drilled. On top of the main bore liner there is installed a seal bore divert, whose purpose is to guide the lateral liner into the lateral. As the Hydrasplit lateral liner is run to the top of the main bore liner, circulation is started and measurement from the MWD is read.

Prior to running down and landing the Hydrasplit, the Hydrasplit is orientated to allow the lateral liner to enter the lateral. At the bottom of the lateral liner there is installed a bullnose with a greater outer diameter then the inner diameter of the main bore entering in the main bore diverter. This is done to prevent the lateral liner to get stuck in the main bore and start to buckle.

As the lateral liner is run into the lateral, the Hydrasplit land in the main bore diverter. When the Hydrasplit enters the main bore diverter, the main bore slick stinger will be guided in to the main bore diverter and into the top of the seal protection sleeve.

Applying weight, approximately 10 tons, on top of the seal protection sleeve will cause the shear screws to shear and the sleeve will start to move downwards as the main bore slick stinger is lowered further down. As the main bore slick stinger is in place there will be a tight seal around the stinger.

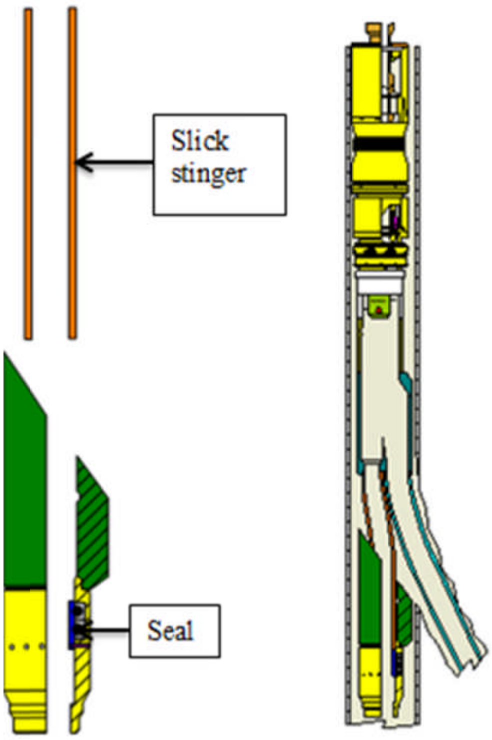

Figure 5-21- Illustrates connection between lower main bora and junction [23]

After landing the Hydrasplit in the seal bore diverter, the liner hanger needs to be set. The setting the liner hanger is achieved by hydraulics. Dropping a ball inside the running tool and chasing it down to land in a ball seat, will allow the running tool to be closed off. When the running tool is closed off, it is possible to get fluid in to the setting chamber of the liner hanger. When pressuring the running tool against the ball, the pistons installed inside the setting chamber will start to move and the slips on the liner hanger will be set.

Increasing of the pressure after the slips are set will make the ball seat shear out, the running tool will then release and circulation through the running tool will be possible again. To set the liner hanger packer, the running tool needs to be pulled out of the liner hanger until the Packer setting dog sub (figure 5-7) is above the top of the liner hanger.

The setting of the liner hanger element is performed by setting down weight on top of the liner hanger, approximately 35 tons. This exercise will compress the element, and make it squeeze out against the casing wall. The element is kept in this position by a body-lock ring. After the packer is set, it is pressure tested to confirm correct installation.

5.2.2 Quick Connect Swivel [10] [58]

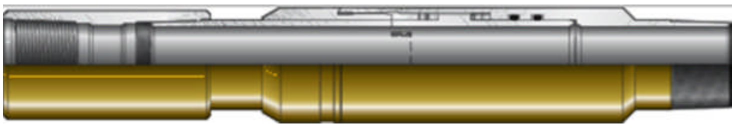

Figure 5-22- Quick connect swivel [58]

When running in with the Hydrasplit ML junction, the lateral liner is connected to the Hydrasplit. The lateral liner could be quite long, several hundred meters, when running these liners. It is also required that the Hydrasplit is able to align as it is supposed to. When landing in the seal bore diverter, it is necessary that the Hydrasplit is able to rotate separate from the lateral liner. Making up the Hydrasplit to the lateral liner on drill floor is also a challenge due to the two separately bores from the Hydrasplit. To make this connection possible, it is necessary to have a quick connection. The quick connection does not require any rotation of either the lower part or the upper-part of the string.

5.2.3 4 1/2" x 6 5/8" X-over [49]

Figure 5-23- X-over [49]

The X-over is used to change between casing and tubing sizes and between thread types.

5.2.4 Line Slot Wirewrapped Screens

In the lateral section of this well, the same sand screens as used in the main bore lower completion is used. See chapter 5.1.4

5.2.5 Swellable Flow Constrictors

In the lateral section of this well, the same swellable packers as used in the main bore lower completion is used. See chapter 5.1.5

5.2.6 Reamer Shoe

In the lateral section of this well, the same reamer shoe as used in the main bore lower completion is used. See chapter 5.1.6

6 Metallurgy of components installed in a well. [7] [8]

Material used in a production or an injection well on the Norwegian continental shelf is regulated by a set of standards, such as NORSOK STANDARD D-010 and M-CR-701. Materials must be selected with caution, due to the harsh environment it will be installed in.

Governmental requirements must also be fulfilled, and the requirements differ based on the type of environment the material shall be installed in. With different requirements, it means that it must be taken in to account that the environment can vary in each well. Material used must withstand, if present, stimulation fluids, methanol, CO_2, H_2S, descaling fluids, corrosion inhibitors, biocides and other gases or fluids if present. Governmental requirements also regulates to which extent corrosion of the material is allowed.

The Norwegian government has also set requirements regarding other design parameters, which must be fulfilled prior to be granted permission to install a completion. Design factors as burst loads, collapse loads, axial loads and tri-axial loads must be within regulations prior to starting the completion work. Minimum design factors set from the Norwegian government is[7]:

- Burst: 1,10
- Collapse: 1,10
- Axial 1,25
- Tri-axial yield:1,25 (pipe body and connection whichever combination is weaker)

7 Tubing movement and stress [2] [9] [11] [64]

After it has been installed and bears a pressing load in the well, the tubing string could be in a straight-line, a sinusoidal buckling state or in a helical buckling state. The tubing string that is installed is normally not in a straight line state, but more often in an irregular helical shape, combined with several inflexion points.

The final shape of the tubing string is dependent on the borehole and the length of the tubing string. Different shapes and loads exposed to the tubing string could make the tubing string fail prematurely. It is therefore important to take in to account the forces acting on the tubing. This chapter will focus on some of the calculations that need to be taken into account prior to installation of the tubing string.

String inflexion occurs due to external forces exposed to the tubing string. This could be several forces, such as axial force, fluid pressure, bending rigidity of the string cross-section, tubing string length, buoyant weight of the tubing string, borehole or casing size, friction and constraining condition of the end.

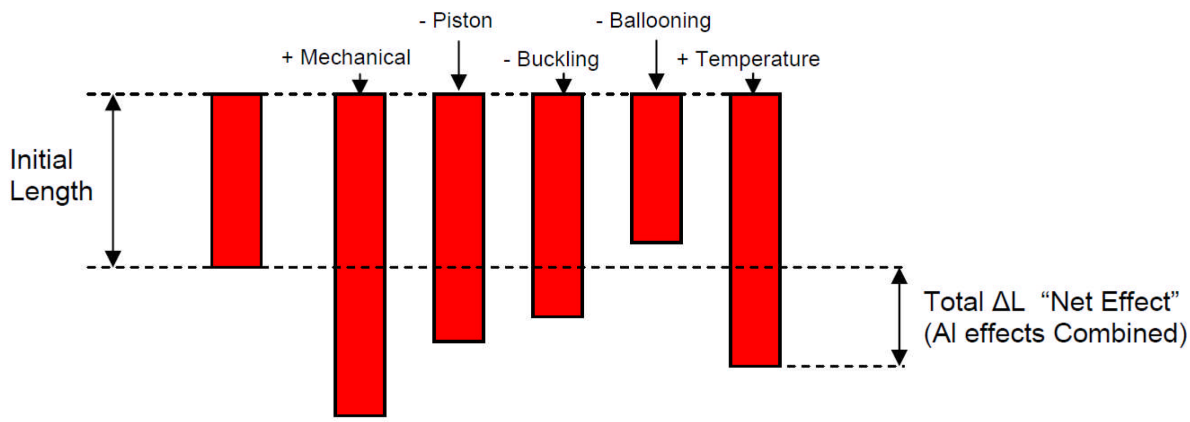

Figure 7-1- Tubing movement due to forces affecting the tubing sting [64]

When tension is applied to the tubing string after the production packer is set, the tubing string will stretch a length ΔL. The length change is calculated using equation 7.1.

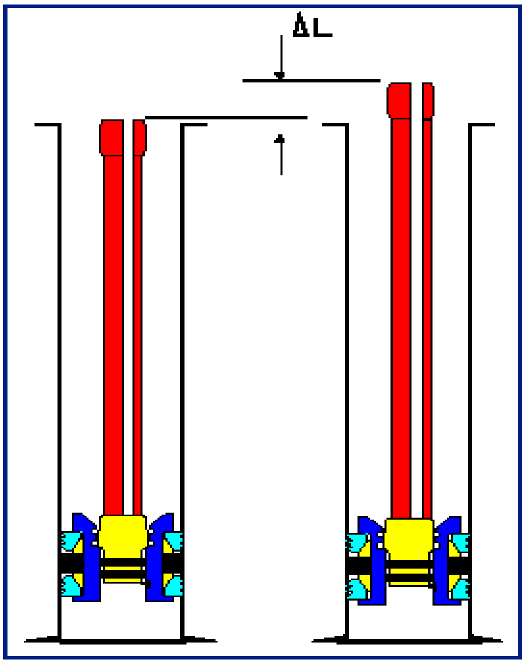

Figure 7-2- Length change due to stretch

$$\Delta L = \frac{L\ x\ F}{E\ x\ A_s} \qquad 7.1$$

Where:

$\Delta L = Length\ change,\ m$
$L = Length\ of\ tubing,\ m$
$F = Force,\ Pa$
$E = elastic\ modulus,\ Pa$
$A_s = Cross\ sectional\ area\ of\ tubing, m^2$

Critical inflexion load determination could be calculated by the following equations. Helical buckling in the tubing string could occur when the tubing string is pressed to a certain point. Critical buckling load could then found be using equation 7.2. This equation is derived using the energy method.

$$F_{cr} = 5{,}55x(EIW_e^2)^{1/3} \qquad 7.2$$

Where:

$F_{cr} = critical\ helical\ bucling\ load,\ N$
$E = elastic\ modulus,\ Pa$
$I = cross - sectional\ inertia\ moment,\ m^4$
$W_e = buoyancy\ weight\ of\ string\ per\ unit\ length,\ N/m$

Both internal and external pressures have an effect on the axial load, therefore equivalent axial forces must be included in the analyze. This leads to equation 7.3

$$F_e = F - (p_i + f_i v_i^2)A_i + (p_o + f_o v_o^2)A_o \qquad 7.3$$

Where:

$F_e = equivalent\ axial\ force,\ N$
$F = actual\ axial\ force,\ N$
$p_i = pressure\ inside,\ Pa$
$p_o = pressure\ outside,\ Pa$
$v_i = fluid\ velocities\ inside\ tubing,\ m/sec$
$v_o = fluid\ velocities\ outside\ tubing,\ m/sec$
$f_i = friction\ factor\ for\ internal\ flow\ inside\ tubing,\ bar/(\frac{m}{sec})^2$
$f_o = friction\ factor\ for\ flow\ in\ annulus\ outside\ tubing,\ bar/(\frac{m}{sec})^2$
$A_i = cross - sectional\ area\ of\ tubingstring\ inside,\ m^2$
$A_o = cross - sectional\ area\ of\ tubingstring\ outside,\ m^2$

Using the two equations above, you can determine if the tubing string is in a straight line stable state or if it is in a helical buckling state. If $F_e \geq F_{cr}$, the tubing string could generate sinusoidal or helical buckling. If $F_e < F_{cr}$, the tubing string is in a straight line stable state.

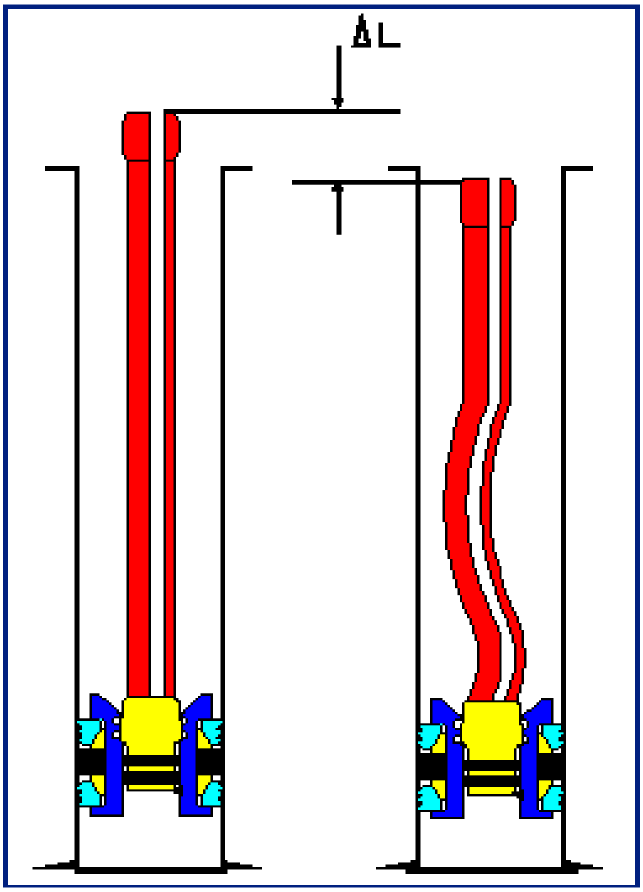

Figure 7-3- Buckling [64]

If $F_e \geq F_{cr}$, the tubing string will generate helical buckling. The contact loads can be calculated by using the following equations. Equation 7.4 shows the geometrics.

$$U_1 = rCos(\theta),\ U_2 = rSin(\theta),\ \theta = 2\pi z/p \qquad 7.4$$

Where:

$U_1 = location\ of\ axes\ of\ tubingstring\ in\ x - axis,\ m$
$U_2 = location\ of\ axes\ of\ tubingstring\ in\ y - axis,\ m$
$\theta = helix\ angle,\ (°)$
$r = radial\ distance\ between\ tubingstring\ and\ casing\ wall,\ m$
$p = helix\ pitch,\ m$
$z = vertical\ height\ above\ neutral\ point,\ m$

There is a relation between equivalent axial force and helical pitch, this relationship is shown in equation 7.5.

$$P^2 = \frac{8\pi^2 EI}{F_e} \qquad 7.5$$

Where:

$P^2 = Length\ along\ the\ tubingstring\ during\ one\ rotation\ of\ the\ helix\ pitch$
$E = elastic\ modulus,\ Pa$
$I = cross - sectional\ inertia\ moment,\ m^4$
$F_e = equivalent\ axial\ force,\ N$

When there is contact between tubing string and casing, equation 7.6, could be used to determine the contact load per unit length of tubing string.

$$W_n = \frac{rFe^2}{4EI} \qquad 7.6$$

Where:

$W_n =$
$contact\ load\ during\ contact\ between\ tubing\ string\ per\ unit\ length\ and\ casing\ wall, N/m$
$r = radial\ distance\ between\ tubing\ string\ and\ casing\ wall,\ m$
$F_e = equivalent\ axial\ force,\ N$
$E = elastic\ modulus,\ Pa$
$I = cross - sectional\ inertia\ moment,\ m^4$

Helical buckling effect, piston effect, ballooning effect, and temperature effect are all effects that could lead to deformation of the tubing string. The following equations could be used to calculate deformation of the tubing string.

Thermal shrinkage or expansion of the tubing string is caused by the changes that occur due to production of hot reservoir fluids, and the temperature difference between formation temperature and injected fluids. Such thermal effects could change tubing length considerably. To calculate the tubing string length change, equation 7.7, could be used.

$$\Delta L_w = 3{,}61x10^{-6} x L_t x \Delta \bar{T} \qquad 7.7$$

Where:

$\Delta L_w = change\ of\ tubing\ string\ length\ due\ to\ temperature\ effect\ ,\ m$
$L_t = tubing\ string\ length,\ m$
$\Delta \bar{T} = change\ of\ mean\ temperature,\ °C$

When the tubing string is landed and locked onto the wellhead with the tubing hanger and the production packer is set, there is limited space for the tubing string to move. This leads to a generation of forces locked in by the tubing string. Equation 7.8 is used to calculate this force.

$$F_w = 75{,}81\ x\ A_{tw} x \Delta \bar{T} \qquad 7.8$$

Where:

$F_w = force\ due\ to\ temperature\ effect\ ,\ N$
$A_{tw} = tubing\ wall\ cross - sectional\ area,\ cm^2$
$\Delta \bar{T} = change\ of\ mean\ temperature,\ °C$

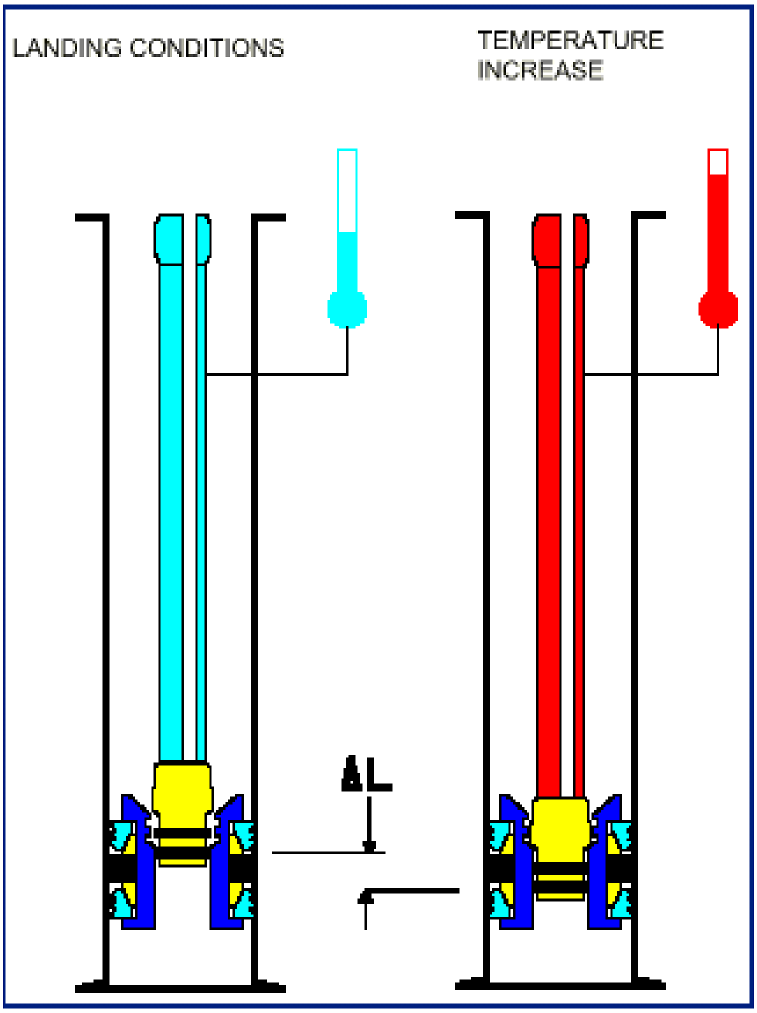

Figure 7-4- Temperature effects of length of tubing string [64]

The piston effect, due to pressure in the annulus, could lead to deformation of the tubing string. Pressure in the annulus at the packer and pressure inside the tubing on areas with different ID could result in forces acting on the tubing string due to the piston effect. Equations used to calculate forces due to the piston effect follows below.

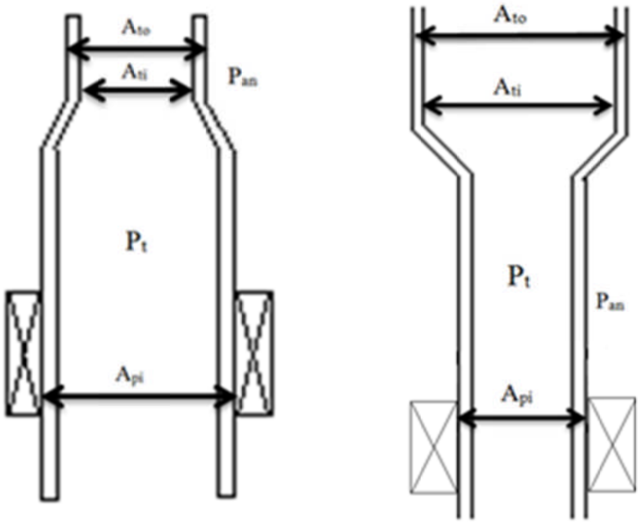

Figure 7-5- Effective piston areas [2]

$$F_h = [\Delta p_t(A_{pi} - A_{ti}) - \Delta p_{an}(A_{pi} - A_{to})]x10^{-4} \qquad 7.9$$

Where:

$F_h = force\ due\ to\ piston\ effect\ ,\ N$

$\Delta p_t = change\ of\ pressure\ in\ tubing\ at\ packer, Pa$

$A_{pi} = area\ of\ packer\ ID,\ cm^2$

$A_{ti} = area\ of\ tubing\ ID,\ cm^2$

$\Delta p_{an} = change\ of\ pressure\ in\ annulus\ at\ packer,\ Pa$

$A_{to} = area\ of\ tubing\ OD,\ cm^2$

$$\Delta L_h = \frac{L_t}{EA_{tw}}[\Delta p_t(A_{pi} - A_{ti}) - \Delta p_{an}(A_{pi} - A_{to})] \qquad 7.10$$

Where:

$\Delta L_h = change\ of\ tubingstring\ length\ due\ to\ piston\ effect\ ,\ m$

$L_t = tubing\ string\ length,\ m$

$E = elastic\ modulus\ (2{,}06\ x10^{11}), Pa$

$A_{tw} = cross - sectional\ area\ of\ tubing\ steel\ material, cm^2$

$\Delta p_t = change\ of\ pressure\ in\ tubing\ at\ packer, Pa$

$A_{pi} = area\ of\ packer\ ID,\ cm^2$

$A_{ti} = area\ of\ tubing\ ID,\ cm^2$

$\Delta p_{an} = change\ of\ pressure\ in\ annulus\ at\ packer,\ Pa$

$A_{to} = area\ of\ tubing\ OD,\ cm^2$

Deformation of the tubing string could also occur due to the ballooning and the reverse ballooning effect. Pressure inside the tubing string could cause ballooning effect of the tubing string diameter. If the tubing string is expanded due to ballooning, its length will also be shortened. The opposite will happen if the annulus is pressurized and the tubing string is squeezed. Equation 7.11 calculates the change in length, and equation 7.12 calculates the force acting on the tubing string.

$$\Delta L_g = \frac{2v_t}{E} x \frac{\Delta\overline{p_t} - R^2 \Delta\overline{p_{an}}}{R^2 - 1} \qquad 7.11$$

Where:

$\Delta L_g = change\ of\ tubingstring\ length\ due\ to\ ballooning\ effect\ ,\ m$
$v_t = Poisson'sratio\ (v = 0{,}3\ for\ steel)$
$E = elastic\ modulud\ (2{,}06\ x10^{11}), Pa$
$R = ratio\ of\ tubing\ OD\ to\ tubing\ ID, dimensionless$
$\Delta\overline{p_t} = change\ of\ mean\ pressure\ in\ tubing\ at\ packer, Pa$
$\Delta\overline{p_{an}} = change\ of\ mean\ pressure\ in\ annulus\ at\ packer,\ Pa$

$$F_g = 6{,}1x10^{-6}(\Delta\overline{p_t} x\ A_{ti} - \Delta p_{an} x A_{to}) \qquad 7.12$$

Where:

$F_g = Foce\ acting\ on\ the\ tubing\ string$
$\Delta\overline{p_t} = change\ of\ mean\ pressure\ in\ tubing\ at\ packer, Pa$
$A_{ti} = area\ of\ tubing\ ID,\ cm^2$
$\Delta p_{an} = change\ of\ pressure\ in\ annulus\ at\ packer,\ Pa$
$A_{to} = area\ of\ tubing\ OD,\ cm^2$

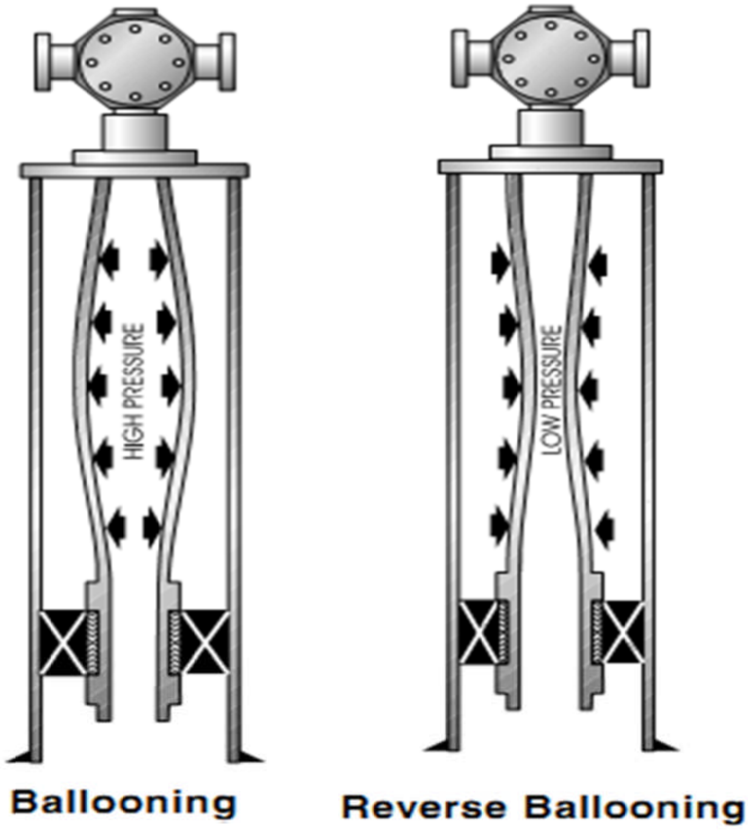

Figure 7-6- Ballooning and reverse ballooning effect [64]

If $P_t > P_{an}$, the tubing string will tend to helical buckle. If helical buckling occurs, the tubing string will be shortened. The force due to helical buckling is minimal and is usually neglected. Change in tubing string length due to helical buckling is computed with equation 7.13.

$$\Delta L_e = \frac{1{,}25 \ x \ 10^{-3} x \ r^2 \ x \ {A_{pi}}^2 (\Delta p_t - \Delta p_{an})^2}{EI(w_t + w_{ft} - w_{fd})} \tag{7.13}$$

$$r = \frac{d_{ci} - d_{to}}{2} \tag{7.14}$$

$$I = \frac{\pi(d_{ci}^4 - d_{to}^4)}{64} \tag{7.15}$$

Where:

$\Delta L_e = change\ of\ tubingstring\ length\ due\ to\ helical\ bukling\ effect\ ,\ m$
$r = gap\ radius\ between\ tubing\ OD\ (d_{to}) and\ casing\ ID\ (d_{ci}), cm$
$E = elastic\ modulud\ (2{,}06\ x 10^{11}), Pa$

R = ratio of tubing OD to tubing ID, dimensionless
A_{pi} = area of packer ID, cm^2
Δp_t = change of pressure in tubing at packer, Pa
Δp_{an} = change of pressure in annulus at packer, Pa
d_{ci} = casing ID, cm
d_{to} = tubing OD, cm
w_t = tubing string gravity, N/m
w_{ft} = tubing string gravity in liquid, N/m
w_{fd} = gravity of liquid displaced, N/m
I= inertia moment of tubing string, cm^4

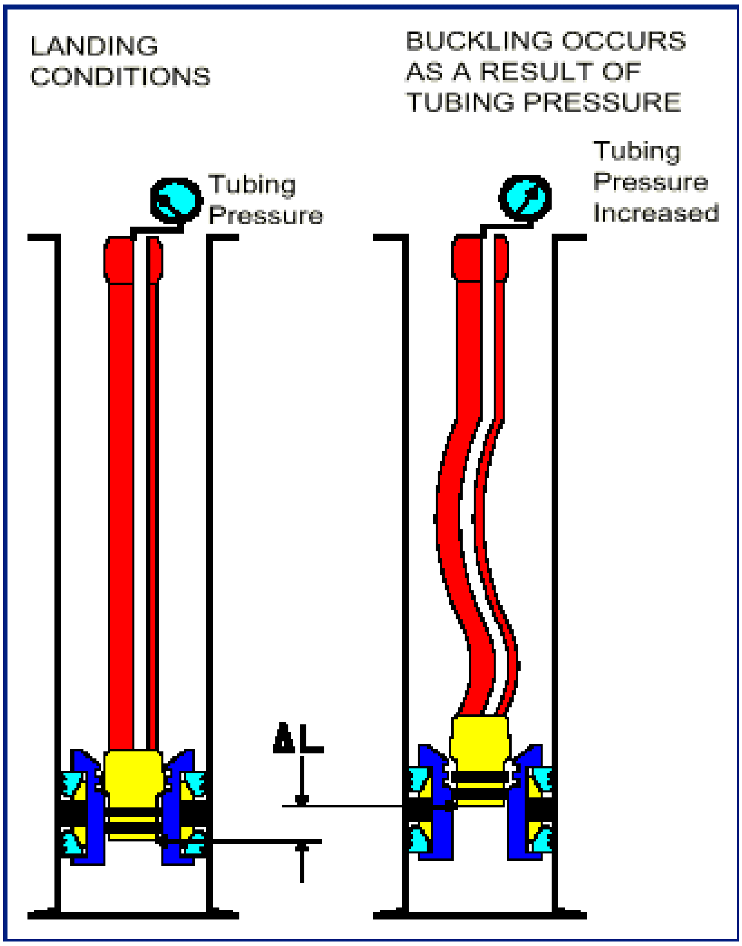

Figure 7-7- Buckling due to pressure effect [64]

Tubing string design has to be designed using safety factors. The following equations show how to calculate some of the safety factors.
Tension safety factor is calculated using equation 7.16

$$K_{RD} = \frac{F_{RD}}{W_e L} \qquad 7.16$$

Where:

$K_{RD} = tension\ safety\ factor\ of\ tubing\ string\ , dimensionless$
$F_{RD} = tensile\ strength\ of\ tubing\ string, N$
$W_e = buoyancy\ weight\ of\ string\ per\ unit\ length,\ N/m$
$L = tubing\ string\ length, m$

Safety factors for internal pressure and safety factor for collapse are calculated from the equation 7.17

$$K_{Ri} = \frac{P_{Ri}}{P_i - P} \qquad 7.17$$

$$K_{Ro} = \frac{P_{Ro}}{P_o - P_i} \qquad 7.18$$

Where:

$K_{Ri} = internal\ pressure\ factor\ , dimensionless$
$K_{Ro} = collapse\ safety\ factor\ factor\ , dimensionless$
$P_{Ri} = internal\ pressure\ strength,\ Pa$
$P_i = pressure\ inside,\ Pa$
$P_o = pressure\ outside,\ Pa$
$P_{Ro} = collapse\ strength, Pa$

The tubing string is exposed to a three dimensional stress environment. Analyses of the three dimensional stress is broken down into the following equations.
Axial stress affecting the tubing string due to actual axial force is calculated by equation 7.19

$$\sigma_{z1} = \frac{F_d}{A_s} \qquad 7.19$$

Where:

$\sigma_{z1} = axial\ stress\ caused\ by\ actual\ axial\ force, N/m^2$
$F_d = actual\ axial\ force\ of\ potential\ dangerous\ cross - section, N$
$A_s = cross - sectional\ area\ of\ dangerous\ cross - section,\ m^2$

Axial stress experienced by the tubing string due to helical buckling is calculated by equation 7.21.

$$\sigma_{z2} = \begin{cases} \frac{F_{ed} r r_d}{2I_d}, & Z_d \leq L_{ni}, i=1,2,3 \\ 0 & Z_d > L_{ni}, i=1,2,3 \end{cases} \qquad 7.20$$

Where:

$\sigma_{z2} = axial\ stress\ caused\ by\ helical\ buckling$
$F_{ed} = equivalent\ axial\ force\ of\ dangerous\ cross-section, N$
$r = gap\ radius\ between\ tubing\ OD\ (d_{to}) and\ casing\ ID\ (d_{ci})$
$r_d = radial\ distance\ of\ arbitrary\ point\ on\ dangerous\ cross-section,\ m$
$I_d = inertia\ moment\ of\ dangerous\ cross-section,\ m^4$
$Z_d = location\ of\ dangerous,\ m$

Radial stress experienced by the tubing string due to external and internal pressure is calculated by equation 7.22

$$\sigma_\theta = \frac{P_{id} r_{id}^2 - P_{od} r_{od}^2}{r_{od}^2 - r_{id}^2} - \frac{r_{od}^2 r_{id}^2 (P_{id} - P_{od})}{(r_{od}^2 - r_{id}^2) r_d^2} \qquad 7.21$$

$$\sigma_r = \frac{P_{id} r_{id}^2 - P_{od} r_{od}^2}{r_{od}^2 - r_{id}^2} + \frac{r_{od}^2 r_{id}^2 (P_{id} - P_{od})}{(r_{od}^2 - r_{id}^2) r_d^2} \qquad 7.22$$

Where:

$\sigma_\theta = tangential\ stress, Pa$
$\sigma_r = radial\ stress, Pa$
$P_{id} = internal\ pressure\ at\ dangerous\ cross-section,\ Pa$
$P_{od} = external\ pressure\ at\ dangerous\ cross-section,\ Pa$
$r_{id} = inside\ radius\ at\ dangerous\ cross-section,\ m$
$r_{od} = outside\ radius\ at\ dangerous\ cross-section,\ m$
$r_d = radial\ distance\ of\ arbitrary\ point\ on\ dangerous\ cross-section,\ m$

Equivalent stress is shown in equation 7.23.

$$\sigma_{zd} = \frac{\sqrt{2}}{2}\sqrt{(\sigma_{z1} + \sigma_{z2} - \sigma_r)^2 + (\sigma_{z1} + \sigma_{z2} - \sigma_\theta)^2 + (\sigma_r - \sigma_\theta)^2} \qquad 7.23$$

Safety factor is then calculated by equation 7.24.

$$K_{zd} = \frac{[\sigma]}{\sigma_{zd}} \tag{7.24}$$

Where:

$K_{zd} = safety\ factor$
$[\sigma] = permissible\ stress, Pa$

Total safety factor is then calculated by using equation 7.25.

$$K_s = min\{K_{RD}, K_{Ri}, K_{Ro}, K_{zd}\} \tag{7.25}$$

Where:

$K_s = total\ safety\ factor$
$K_{RD} = tension\ safety\ factor\ of\ tubing\ string\ , dimensionless$
$K_{Ri} = internal\ pressure\ factor\ , dimensionless$
$K_{Ro} = collapse\ safety\ factor\ factor\ , dimensionless$
$K_{zd} = safety\ factor$

Ultimate operational parameters are then determined by using the following equations. Residual tensile force is calculated by using equation 7.26.

$$F_R = F_{RD} - K_s W_e L = (K_{RD} - K_s) W_e L \tag{7.26}$$

Where:

$F_R = axial\ stress, Pa$
$F_{RD} = tensile\ strength\ of\ tubing\ stirng, N$
$K_s = total\ safety\ factor$
$W_e = buoyancy\ weight\ of\ string\ per\ unit\ length,\ N/m$
$L = tubing\ string\ length, m$
$K_{RD} = tension\ safety\ factor\ of\ tubing\ string\ , dimensionless$
$K_s = total\ safety\ factor$

Maximum operating pressure difference with respect to the inner wall of the tubing string is calculated by equation 7.27.

$$\Delta P_{maxi} = \frac{P_{Ri}}{K_s} \qquad 7.27$$

Where:

$P_{Ri} = internal\ pressure\ strength,\ Pa$
$K_s = total\ safety\ factor$

Maximum operating pressure difference with respect to the outer wall of the tubing string is calculated by equation 7.28.

$$\Delta P_{maxo} = \frac{P_{Ro}}{K_s} \qquad 7.28$$

Where:

$P_{Ro} = collapse\ strength, Pa$
$K_s = total\ safety\ factor$

This calculation leads to equation 7.29. This is used to calculate the safe operating pressure difference of the tubing string.

$$\Delta P_{max} = min\{\Delta P_{maxi}, \Delta P_{maxo}\} \qquad 7.29$$

8 Future solutions [9] [10]

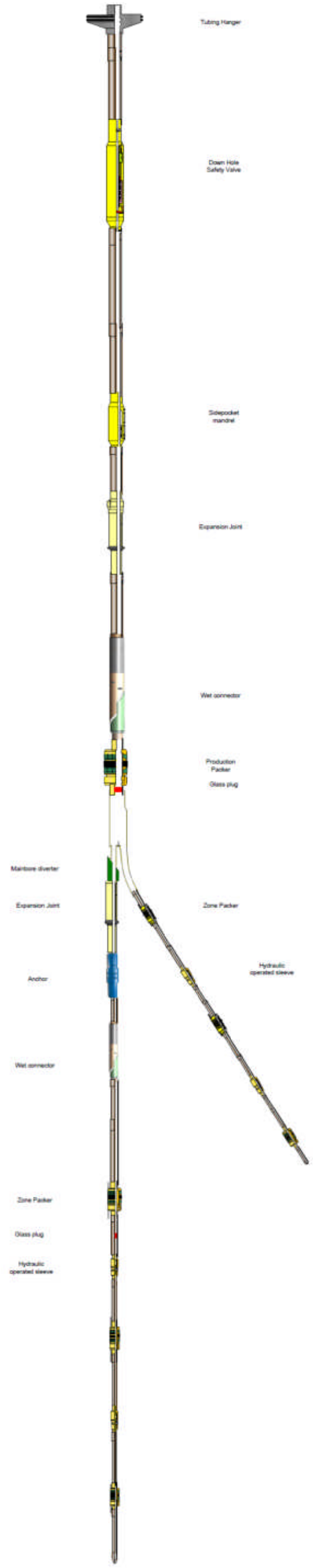

Figure 8-1- Future solution 1

With the technology existing today, it is not possible to install hydraulically operated sleeves in to each of the existing branches of a multilateral well. The benefits of having this type of technology could be great. Being able to control the production from a lateral leg in different zones instead of producing from the entire lateral as one, could improve production rates, as a lateral leg could be several hundred meters long. Being able to control the drawdown with chokes, to alternatively close down a zone that starts to produce water could lead to longer production lifetime of the well.

To be able to install a well with the required equipment, it would require conventional intelligent completion equipment, as described earlier in this thesis. Hydraulic operated sleeves, packers with feed through futures, gauge carriers and control lines could be used to operate the different sleeves and to send signals from the gauge carriers to the surface.

New and nonconventional equipment must also be implemented for this solution to be successful. There are a couple of new components that must be added to the completion string for this to be an optimal solution. The next chapter contains further information about the equipment that must be used as an addition to the completion solution described earlier.

There are several challenges that must be faced prior to being able to complete a well with several zones in both the lateral and the main bore. The biggest challenge is to get the control lines to connect from the lateral and the main bore through the junction. Using some of the technology that exists today, for instance a tool called a wet disconnect-reconnect tool, chapter 8.4.1, and designing a connection device that could be installed in the top of the junction to allow the control lines to pass through the junction, the solution could be successful.

One optional solution to this problem would be to modify the existing equipment, to allow the control lines to be installed all the way out in to the lateral, to the bottom of the main bore and through the junction.

To be able to achieve this solution, the completion must be installed in steps. The first step would be to drill the main bore of the well, and install the required casing and liner. When the main bore has been drilled, the lateral can be drilled using a whipstock.

The whipstock is then installed, and the casing window is milled. After the window is milled, the milling tool is pulled out and a BHA that can drill the lateral is prepared. The lateral is drilled as required, and the drilling BHA is pulled out. With the whipstock still installed, the liner for the lateral can be installed using the whipstock as a guide to the lateral.

After the liner is installed in the lateral, the well needs to be cleaned for potential milling, drilling and cement remains. After the well has been cleaned, the whipstock can be retrieved using the whipstock pulling tool. When the whipstock has been retrieved and is pulled out of the well, the main bore also needs to be cleaned, using a conventional cleanup BHA.

Up until this point, the work described is conventional well construction. From this point forward the technology is new, and the equipment that has not yet been tested with this configuration. Appendix G, illustrates this well
Both modified versions of existing completion equipment and new equipment made for this completion solution is required to make this solution successful.

The new equipment that must be fabricated is a lateral diverter. This diverter has to be designed in a way that allows the lateral leg on the junction to be lead out to the lateral, and have a hole big enough to allow for the main bore completion wet disconnect-reconnect tool male part to pass through.

The lateral is guided out through the lateral using a bull nose, which is bigger than the inner diameter (ID) of the lateral diverter, in the end of the lateral leg completion.

The junction must also be modified. Instead of running the junction with a liner hanger packer, this junction must be installed with a production packer with control line feed through features. This is to allow for control lines from the lateral sleeves and any potential gauge carriers that are installed in the lateral, to be terminated in a female wet disconnect-reconnect tool installed above the junction.

The junction also has a main bore stinger the bottom, and this stinger has to be modified. Instead of the stinger being mounted originally, it has to be fitted with a male wet disconnect-reconnect tool in the bottom of the stinger. This wet disconnect-reconnect tool is intended to latch on to the lower middle completion, allowing the control line connections from the bottom main bore completion to have a routing up and through the junction.

When the main bore lower completion and the lateral completion are installed as described above, it allows for the upper completion to be installed with a male wet disconnect-reconnect tool in the bottom. This will then be latched on to the female wet disconnect-reconnect tool that is installed on top of the junction, and there will be connection between the control lines from the main bore to the control lines in the lateral bore.

To be able to achieve this type of completion solution, there are several challenges that must be faced. Dividing each step of the completion into detailed description, would help to get an overview of the challenges involved in the different tasks.

8.1 Lower main bore completion

Basically, the lower main bore completion could be installed as a standard lower completion, but there are some challenges regarding the setting of the production packer, what position the sleeves must be set to prior to installation, how to run the lower main bore completion down to setting depth and how and when to set the zonal isolation packers.

Installation of the lower main bore completion is performed almost similar to a liner, the lower completion is built together and run down in to the well using drill pipe.

The components in the lower main bore completion would be, starting from the bottom of the completion, a bull plug, a zonal packer, a hydraulically operated sleeve, a gauge carrier, a zonal packer, a hydraulically operated sleeve, a glass plug, a production packer with control line feed through, an expansion joint and a female wet disconnect-reconnect tool. Using the male wet disconnect-reconnect tool as a connection point to the lower main bore completion, this would be run on drill pipe down to its designated setting depth.

When the lower main bore completion is run to its designated depth, the production packer must be set. This procedure is conducted by pressuring up the drill pipe against the glass plug, chapter 8.4.2. After the production packer is set and tested, the glass plug must be broken by applying pressure to the integrated pump system installed inside the glass plug. This must be performed the required number of times. At this stage, the well is open to the reservoir again. Now, it is not possible to set the zonal isolation packers, these will be set at a later stage in the completion phase. After the glass plug is broken, and communication with the reservoir is reestablished, the wet disconnect-reconnect tool is disengaged and the drill pipe and the male wet disconnect-reconnect tool are pulled out of the well.

Prior to running the lower main bore completion, the hydraulically operated sleeves must be set in the open position. The reason this is to allow for fluid to enter into the tubing as the completion is lowered down to the setting depth. This will prevent the lower part (below the glass plug) to collapse due to increased pressure as the completion is run into the well.

When the junction is run at a later stage in the completion phase, the male wet disconnect-reconnect tool has to be stabbed into the female wet disconnect-reconnect tool already installed in the lower main bore completion. As this male wet disconnect-reconnect tool enters the lower completion, a displaced volume of fluid has to be guided out of the lower completion to prevent creating a hydraulic lock.

8.1.1 Lateral diverter [23]

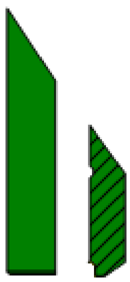

Figure 8-2- Main bore diverter [23]

After the lower main bore completion is installed, the lateral diverter must be installed. This lateral diverter needs to be modified to fit this new system. The diverter will have the same main function as the previous lateral diverter, to guide the lateral completion into the lateral, and to guide the main bore leg into the main bore completion. The challenge here is to make the hole for the main bore completion leg large enough to allow the male wet disconnect-reconnect tool to pass through.

Since the lateral diverter in a conventional system is run with a seal stem below, that is designed to fit on top of the liner hanger packer used to run the conventional lower completion, the lateral diverter also has to be fitted with a conventional drilling anchor, either hydraulic or mechanically set. The anchor must have an ID big enough to allow the male wet disconnect-reconnect tool to pass through.

Figure 8-3- Drilling anchor [59]

8.2 Junction and lateral completion [9] [10]

Installing the junction and the lateral completion can be performed in one operation, modifying the junction from the original design by changing out the liner hanger packer with a production packer with feed through feature.

To be able to set this production packer it is necessary to install a plug to pressure up the production tubing against. This could for instance be a glass plug, installed just below the

production packer. Above the production packer there needs to be a female wet disconnect-reconnect tool, this will be used to connect the upper completion to the lateral and the lower main bore completion control lines to the surface. The female wet disconnect-reconnect tool will also be used to run the junction down into the well using drill pipe, using the same principle as for running the lower main bore completion.
Components in the lateral bore completion would be, starting from the bottom, a bullnose, a zonal packer, a hydraulically operated sleeve, a gauge carrier, a zonal packer, a hydraulically operated sleeve and a quick connect.

Components in the main bore stinger would be, starting from the bottom, a male wet disconnect-reconnect tool and an expansion joint.

One of the main focus areas while running and installing this section of the completion would be to prevent the control lines from getting damaged. Using extra control line clamps as protectors and placing the control lines in an orientation that prevents them from lying on the low side when entering the lateral, would reduce the possibility of control lines from being damaged. In the junction there could be welded on groves, as on the side pocket mandrels, to protect the control lines.

8.3 Upper completion [9]

The upper completion is run as a conventional completion. The equipment for a completion string, starting from the bottom, would be a male wet disconnect-reconnect tool, a chemical injection valve, a side pocket mandrel, an annulus safety valve, a TRSCSSV and a tubing hanger.

Components in the upper completion could be customized to fit the specific well requirements. Only the male wet disconnect-reconnect tool, the TRSCSSV and the tubing hanger are required to be installed in the production tubing string.

Short list of the well construction:

- Drill the main bore of the entire well.
- Install casing/liner
- Run the whipstock and mill the casing window
- Pull out with the milling tool
- Run the BHA that shall be used to drill the lateral section.
- Drill the lateral section.
- Pull out the BHA
- Run lateral liner
- Perforate the lateral liner if required
- Run the pulling tool for the whipstock
- Retrieve the whipstock and pull out.
- Perforate the main bore if required.
- Run a cleanup BHA and clean up the well.
- Run the main bore lower completion.
- Run the lateral diverter.
- Run the junction with the lateral completion.
- Run the upper completion.

8.4 Future solution with mechanical operated sleeves [9] [10]

Using the described solution above, requires the inner diameter of the casing to be large, as the dual pipe below the junction has a large outer diameter. As an alternative, to reduce the required inner diameter of the casing, a solution could be to have mechanically operated sleeves in the main bore and hydraulically operated sleeves in the lateral. This would be a combination of the two solutions described above combined with mechanically operated sleeves.

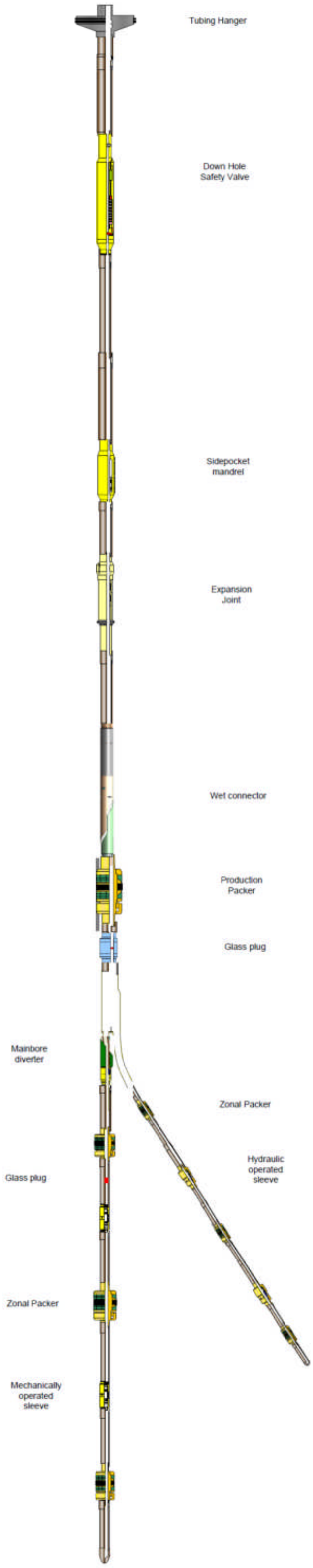

Figure 8-4- Future solution 2

Construction of this type of well will be a combination of the two methods. First, the drilling of the main bore is conducted, then the main bore casing is installed. The lower completion is then installed with zonal separation packers, mechanical sliding sleeves and a liner hanger packer with the orienting profile on top of the packer. This profile will be used when the whipstock is installed. Appendix H, illustrates this well.

Installation of the main bore completion is performed with drill pipe combined with MWD tools, which can read the orientation of the orienting profile on top of the liner hanger packer. These readings are then used to orientate the seal bore diverter below the whipstock. This will guide the whipstock into the designated orientation, and the window will then be drilled in the intended direction. Running of the whipstock is conducted as described in chapter 2-8.

After the window is milled and the lateral is drilled, the junction is ready to be installed. With this completion solution the junction and lateral completion are installed in one run, and the main bore completion will also be connected to the junction in the same run.

The lateral completion will consist of, starting from the bottom, a bullnose, a zonal packer, a hydraulically operated sleeve, a gauge carrier, a zonal packer, a hydraulically operated sleeve and a quick connect. The quick connect is used to make up the junction to the lateral completion. It is not possible to rotate neither the junction nor the lateral completion due to the control line connected. And the quick connect is used to connect them to each other without them having to rotate.

Protection of the control lines during running of this part of the completion is critical, damage to the control lines during running will not be noticed until the main bore upper completion is installed. Extra protection control line clamps must be installed, and extra protective grooves must be welded or grinded on to the equipment to protect the control lines.

The main bore stinger will be a standard slick stinger, designed to sting into the main bore seal bore diverter to enable a tight seal between the tubing and the annulus, see figure 8-3. To be able to achieve a tight seal around the junction, a production packer must be installed along with the junction.

For this packer to allow the control lines from the lateral completion to be terminated above the packer, control line feed through features are necessary. Above the production packer there must be a female wet disconnect-reconnect tool connected to the junction. This point will be where the control lines from the lateral completion are terminated and it will also be the connection point for communication with the sleeves in the lateral completion when the main bore upper completion is installed. Installing this junction and lateral completion is commenced by running the completion down using drill pipe.

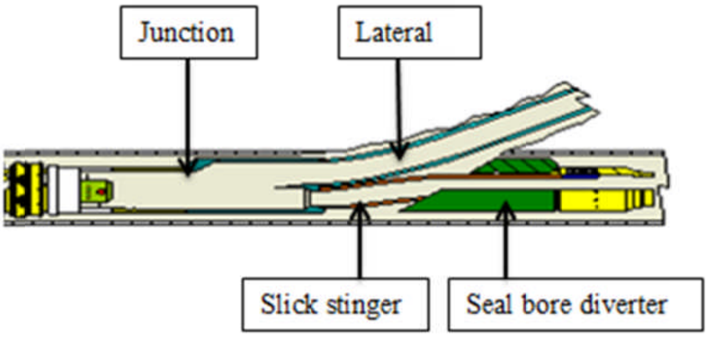

Figure 8-5- Multilateral junction [23]

Inside in the junction, a main bore diverter, figure 8-5, is installed. The primary function of the main bore diverter is to rout the access from the upper main bore to the lower lateral or to the lower main bore, below the junction.

Using the solution with mechanically operated sleeves in the lower main bore, wire line access into the lower main bore is necessary to operate the sleeves. Operation of the mechanical sleeves are conducted using the wire line tool "Otis B shifting tool", see figure 8-7.

Operation of the mechanical sleeves are performed by either pushing the sleeve downwards or pulling the sleeve upwards using the B-shifting tool. As figure 8-7 illustrates, there are threads in both ends of the shifting tool. This is to enable running of the shifting tool in both directions.

Inside the sleeve there is an edge, NO-GO, that is used for shifting the sleeve. As the tool is shifting the sleeve downwards, the shifting NO-GO on the shifting tool laches on to the NO-GO inside the sleeve, pushing the sleeve downwards. For shifting the sleeve upwards, the shifting tool is run the opposite way. The shifting tool is run through the sleeve, and when pulling the shifting tool upwards the shifting NO-GO will latch on to the NO-GO inside the sleeve and pull the sleeve upwards.

An upper main bore completion is installed based on requirements from the customer. Including the male wet disconnect-reconnect tool as the lower component that is installed in this completion string, this is to enable the communication with the sleeves installed in the lateral

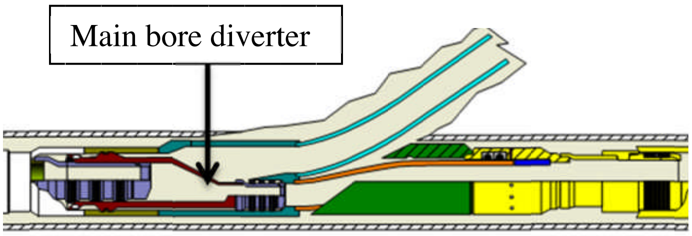

Figure 8-6- Multilateral junction with main bore diverter installed [39]

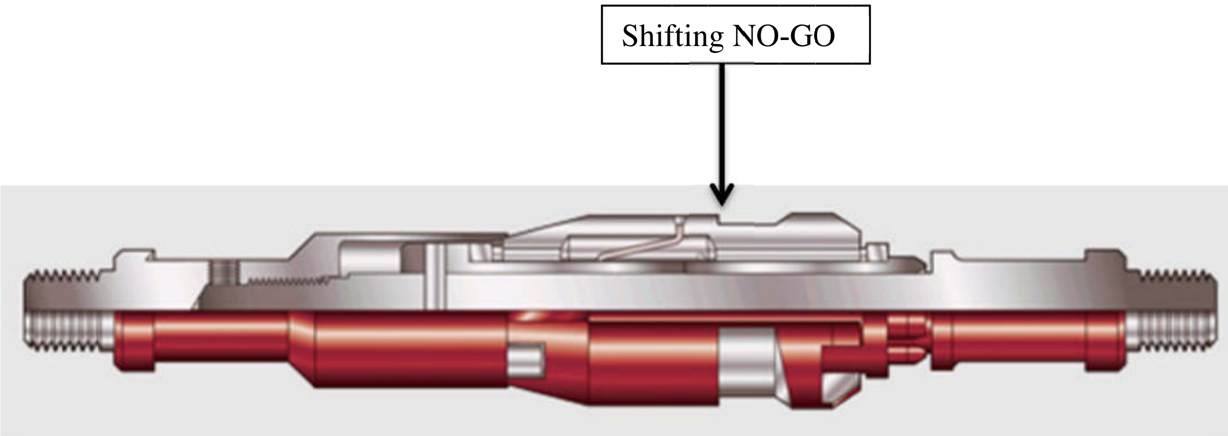

Figure 8-7- Otis model-B shifting tool [60]

8.4.1 Wet Disconnect-Reconnect Tool [26]

Figure 8-8- Wet disconnect-reconnect tool [26]

The wet disconnect-reconnect tool allows for connecting and releasing both hydraulic, electric and fiber optic control lines down hole. Consisting of a male and a female part, the tool is connected down hole with a seal stem that provides tubing to the annulus tight seal, and the control lines are connected using special designed latch couplings in the tool. Mechanically the tool is locked together with a latch anchor.

The wet disconnect-reconnect tool has a capacity of running several hydraulic control lines and electrical or fiber optical control lines. The wet disconnect-reconnect tool is installed as a part of the tubing string. Regarding the connection and reconnection of the tool, there are special designed connectors. The connectors are designed with a flushing feature that allows for washing the connectors prior to connecting the tool. Flushing the connectors will prevent the control line fluid to be contaminated, and also prevent debris from lying between the connectors. This debris could potentially break any seals on the connector or even the connector itself.

The connecting of the male and female part of the wet connector is dependent on the orientation of the two parts as they are being connected. The tool is designed as a self-alignment tool, which means that as the tool is being connected, it will orientate itself to its connection position. Orienting movement of this tool may require a rotational movement of the upper part of the completion. Rotational movement is often not permitted, due to the possibility of damage to control lines connected outside the tubing string. Alternatively this tool could be set up with a rotational feature that only allows the lower part of the tool to rotate while engaging the latch.

8.4.2 Tubing disappearing plug [17]

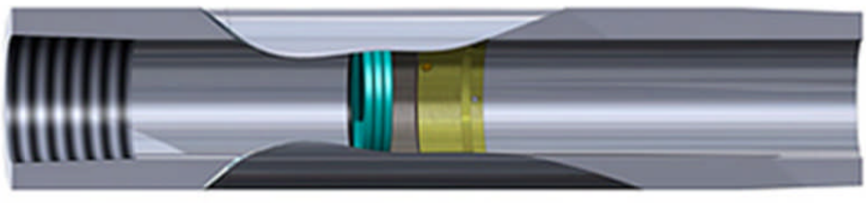

Figure 8-9- Tubing disappearing plug [61]

The company TCO has developed a plug made of glass, that it is installed and run as an integrated part of the completion. The plug is approved as a barrier, and when the plug is activated the glass disintegrates into small particles. Using a glass plug allows for full ID of the tubing after the plug has disintegrated, and no mechanical tools are needed to activate or remove the plug.

This specific plug has an internal pump open device, which is activated by differential pressure. Pressurizing the plug several times will eventually make the glass brake. Seeing as the plug allows repeated pressurizing, makes it possible to set the packer against the plug.

The internal ID of the lower completion, especially through the wet disconnect-reconnect tool, does not allow a conventional plug to be run through. Therefore, this plug is an appropriate preferable solution.

If the plug should fail, and the internal pump open system malfunctions, it is possible to go down and open the plug using wire line operations. If it should be necessary to open the plug mechanically using wire line, this would be possible even with the small ID through the wet disconnect-reconnect tool. The procedure for permanently opening this plug, is to run down with a wire line string with heavy jars and a spear, figure8-8., and hammer the glass until it break.

Figure 8-10- Spear for breaking glass plug [62]

8.4.3 Expansion joint [31] [63]

Figure 8-11- Expansion joint [63]

The expansion joint is a tool designed to collapse when exposed to a predetermined amount of weight. Prior to running the expansion joint, shear pins are installed to prevent the tool from collapsing prematurely.

The purpose of the expansion joint is to arrange for a “soft” latch of the wet disconnect-reconnect tool. When the wet disconnect-reconnect tool is at its designated depth and ready to latch together, weight is applied to perform latch between the lower and upper part of the wet disconnect-reconnect tool. As the wet disconnect-reconnect tool is latched together, more weight is applied to the expansion joint, the preinstalled shear screws will shear and the expansion joint is now able to stroke.

Regarding space-out length, an expansion joint will also be able to compensate if the tubing is too long. When installing production tubing with two fixed connection points, in this case the tubing hanger and the wet disconnect-reconnect tool, getting the tubing to fit exactly is almost impossible due to lengths of available tubing joints and pup joints available. Using an expansion joint is a solution to manage the challenge with the installation length. During production or injection the thermal effect will cause the production tubing to either elongate or contract, and then the expansion joint could be used to prevent the wet disconnect-reconnect tool to disengage.

8.4.4 Mechanically operated sliding sleeve [9] [15] [33]

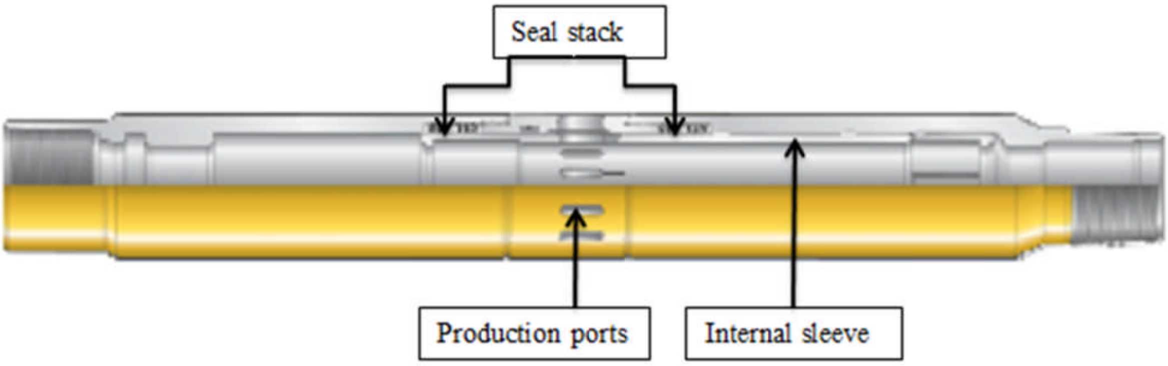

Figure 8-12- Mechanically operated sliding sleeve [33]

Mechanically operated sliding sleeves are installed as a part of the completion string, and allow for communication between the annulus and the tubing when the valve is open. This allows for production through the ports in the sleeve. Operation of this sleeve is performed using an "Otis B-shifting tool", figure 8-7.

Mechanically operated sliding sleeves are designed with a solid body, with machined holes for passing the well stream into the production tubing. Inside the sliding sleeve, there is a machined closing/opening sleeve that is operated with the B-shifting tool. This sleeve is moved either up or down in order to either open or close the sliding sleeve. The inner sleeve is moving up and down on two seal stacks. One seal stack is placed below and one above the machined holes in the body of the sliding sleeve.

Operation of the sleeve is commenced using a B-shifting tool. Running the shifting tool down to the sleeve and either pulling or pushing on the inner sleeve, will cause the sleeve to either open or close.

8.5 Future solution using expandable technology [11]

One of the challenges regarding the multilateral completions, is the limitation of outer diameter in the junction. The multilateral junction is normally installed inside a 9 5/8" casing, where the inner diameter is limited. Using expandable technology together with multilateral systems could result in a larger ID in the junction, and also in the production tubing/liner from the junction and out to the lateral and mainbore.

As figure 8-14 illustrates, using an under reamer when drilling could enlarge the innside diameter of the well. This allows for the casing, liner or junction that is to be installed in a later phase of the well construction, to be able to be expanded. Increasing the size of the production tubing in the lateral, would allow for the lateral leg to be drilled longer. As shown in figure 2-11, the maximum distance between the toe and the heel, is desided based on the frictional pressure drop between them. If the inner diameter of the production tubing is increased, the frictional pressure drop is decreased. This could allow for drilling and completion of longer horizontal lateral branches.

Figure 8-13- Under reamer

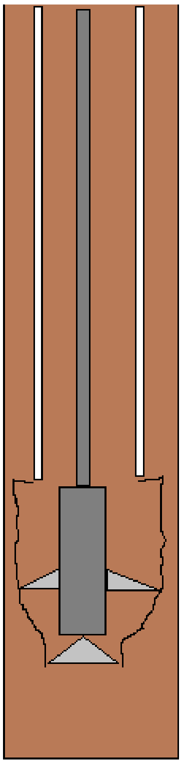

Figure 8-14- Under reaming below casing

Expanding the casing, liner, production tubing or sand screen is performed in one of three ways. One possibility is to use an expansion tool that is hydraulically driven. This is a tool that is run into the well and anchored just above the area that is intended for expansion. As the tool is anchored, it is pressurized, and a piston with an expansion cone is pushed through the pipe that is being expanded. When the piston has stroke its full length, the anchor of the tool is released, and the tool is moved further down into the well. This procedure is then repeated until the entire length of pipe is expanded.

Hydraulic expansion is performed simply by applying mud pressure after the casing or liner is installed. This is an option that is not suited for sand screen, seeing as the sand screens are not able to be pressurized.

Mechanical expansion is performed using a special tapered expansion tool. This tool is designed to be pulled through the pipe, and expand the pipe as it is being pulled back through the pipe.

9 Project considerations [9] [66]

Projects such as planning and installing a well of the type described above, is a time consuming and a long lasting project. The typical timeline for a project like this is 15-20 months, starting from the oil or gas is discovered or from the injector well is found required.

Projects as this involve a number of different companies and an even bigger number of people. The operator company leads the project.

Success in a project like this is only achieved if there is good communication between the involved personnel. This is critical due to the number of involved people in the project. Leadership skills and willingness to delegate tasks to the involved personnel are also among the main keys to success in completing a project like this.

There are usually several involved service companies, delivering equipment to the completion string. Project management inside the service company, would usually be similar to an agile project management strategy.

The project starts with a meeting together with the customer, where the project is presented. Different key factors must then be taken into consideration, for instant if the project is an oil producing well, a gas producer or an injection well, and if it is to be drilled from a platform installation or from a floating vessel and installed as a subsea installation. The project could also be a re-completion of an already existing well that has failed.

Reservoir information, such as pressure, temperature, fluid composition and depth, is information that is important for the well designers prior to starting to design the well solution for the specific well design. When the well designer has received the required information and the component specific design criteria from the customer, a solution for the well design will be introduced to the customer. Together with the customer, the final well design will then be decided.

When the design for the well is decided, production of the required equipment must be initiated. The project manager must then make a plan for the optimal use of the resources available, with respect to the production of equipment, assembly of the parts as they arrive in the workshop and testing of the assembled equipment. Time line for this operation is typically fifteen months.

During this phase, changes in the original plans are not unlikely to accrue. The need for changes could for instance be due to complications during the drilling operations, well construction complications or poorly set reservoir parameter predictions.

Challenges due to changes must be resolved during the project as the project progresses. Supervision from the project manager is important in order for the project to be completed within the project deadline. To be able to handle the challenges due to changes in the project, internal communication within the company is important. Customer communication during the whole project is of course important, but during changes, communication is an even more critical part of the project.

10 Conclusion

There are several advantages of combining the two completion methods, multilateral completion and intelligent well systems. A multilateral well is capable of extending lateral branches into several smaller reservoirs, and comingle the flow of reservoir fluid into one main bore leading to the surface.

Lateral branches can reach out through the same reservoir and drain the reservoir from several locations simultaneously. In larger reservoirs, the permeability could vary within the reservoir, and some spots could even be totally blocked off. By drilling a lateral branch into these blocked off spots, they can be drained simultaneously as the rest of the reservoir.

Intelligent well systems are installed in production or injection wells, to increase the total amount of produced hydrocarbons. An intelligent well system gives the advantage of being able to set different choke openings, using hydraulically operated downhole valves to regulate the flow of produced or injected fluids, combined with an advanced down hole multiphase flowmeter and pressure and temperature gauges, providing real time information. Flow characteristics can be computed, and the production could be controlled from surface and continuously optimized.

When combining these solutions in one single well, production from each lateral becomes controllable. This allows for the ability to control the amount of produced water and unwanted gases. It also gives the ability to shut down production from zones that are drained prior to others, and reduce production from zones that starts to produce water.

The ability to reduce water production from one zone could improve the production period of the well. The handling and treating of large amounts of produced water require separators and is therefore costly. Separators have a maximum limit of how much water they are able to separate, and when this limit is reached, some wells must be shut down. By being able to reduce the water production down in the reservoir, one could therefore improve the production period of the well.

Combining these two completion solutions gives an advanced well solution, with technical challenges and several operations that could run badly. This requires a focused team and accurate planning. This includes accurate calculation of the equipment ability to survive the forces and conditions it is exposed to.

Future work

To provide a better understanding of combining Intelligent Well Systems and multilateral completion, several studies could be performed in the future. As these wells will start to be installed, there will be gathered information about the success rate of these types of wells, and this information could be used to establish even better solutions for future wells.

A technical solution that provides multiple zones in both the main bore and the lateral branch, in a well with combined Intelligent Well Systems and multilateral completion, is not yet developed.

Nomenclature

Annulus	Void between production tubing and casing
Bailed	Gathered using bailer, hydraulic vacuum cleaner
BHA	Bottom Hole Assembly
Bullnose	Bottom part of the string, to seal the tubing
Casing shoe	Bottom part of the casing
Collar	Used to connect two tubing/collar joints
Fines	Fine sand, silt and clay
GLV	Gas Lift Valve
ID	Inner Diameter
KOT	Kick Over Tool
MWD	Measurement While Drilling
Mud	Drilling fluid
NO-GO	Profile to install equipment in
OD	Outer Diameter
PBR	Polished Bore Receptacle
Sand screens	Prevent sand production
SPM	Side Pocket Mandrel
TAML	Classification system of multilateral wells
Tripping	when running drill pipe
TRSCSSV	Tubing Retrievable Surface Controlled Subsurface Safety valve
Wire line	Intervention work performed with wire

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Appendix A

Swellable packer simulation

BAKER HUGHES

InQuest Swell PREdictor™
The Swell PREdictor™ System

Customer Information

Customer Name:		**Rig Name:**	
Geographical Location:		**Well Name / Number:**	
Field:		**Date:**	07.05.2013

Packer Design

Base Pipe OD:	6,63 in	**Element Length:**	10,00 ft
Element OD:	8,17 in	**Reactive Elastomer:**	Oil (Standard REPacker)

Well Information

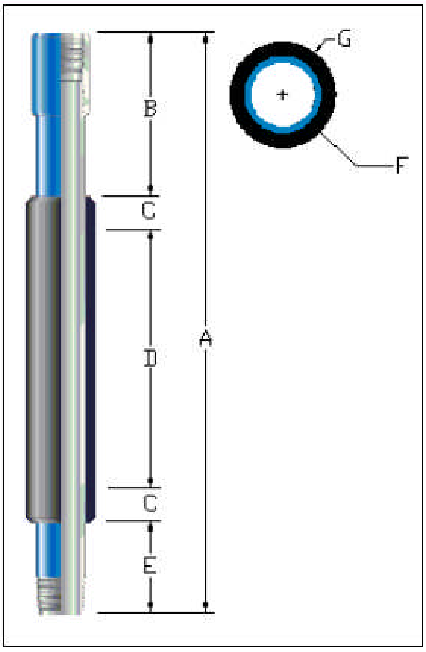
Well MD:	0,00 ft	**BHP (Static):**	5 000,00 psi
Well TVD:	0,00 ft	**BHP (Flowing):**	5 000,00 psi
Minimum Drift:	8,50 in	**BHT (Static):**	95,00 degF
Maximum Deviation:	0,00 dega	**BHT (Flowing):**	95,00 degF
Max. Dog-Leg Severity:	0,00 dega/100ft	**Application Type:**	Open Hole
Setting Depth MD:	0,00 ft	**Casing ID:**	8,54 in
Setting Depth TVD:	0,00 ft	**Gauged Hole:**	No
Setting Depth Deviation:	0,00 dega	**Setting Depth ID:**	8,50 in
Est. Run-in Time:	0,00 h		

Fluid Information

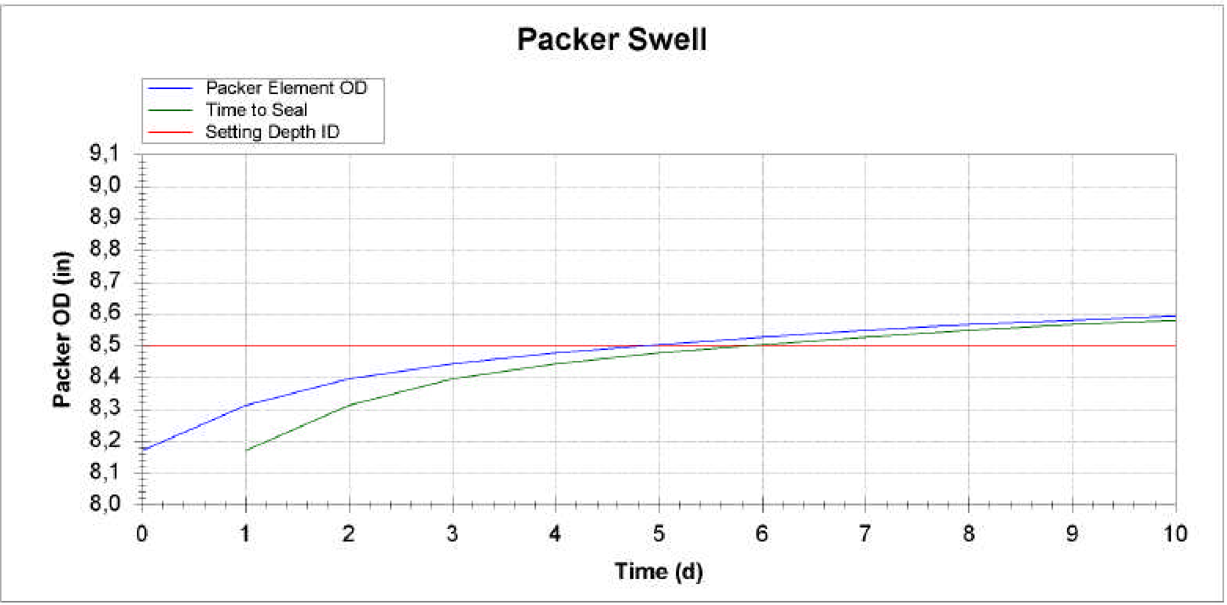
Run-in Fluid:	Oil-based Mud	**Salinity:**	0,70 %
Fluid Density:	10,01 lbm/galUS	**Salts Present:**	NaCl
Viscosity:	0,00 cP	**Comments:**	

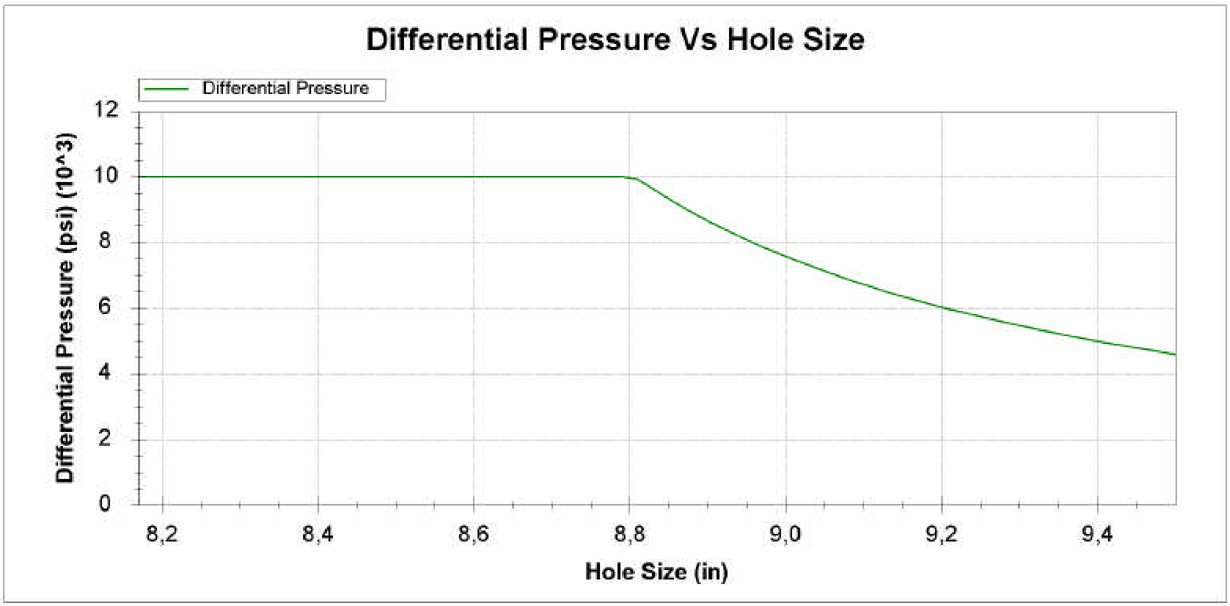
Packer Specs

A=Overall Length:	10,00 ft
B=Upper Handling:	0,00 ft
C=Nitrile Backups:	0,00 ft
D=Element Length:	10,00 ft
E=Lower Handling:	0,00 ft
F=Element OD:	8,17 in
G=Pipe OD:	6,63 in
Reactive Elastomer:	Oil (Standard REPacker)
Thread Type:	
Pipe Material:	
Pipe Weight:	0,00 lbs/ft



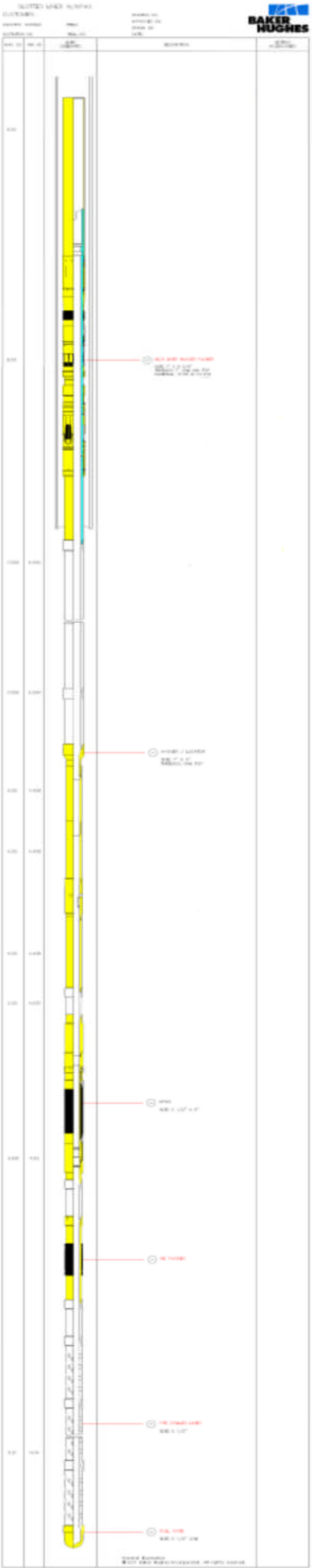
Performance	
Time to Swell:	4,85 d
Time to Seal:	5,85 d
Pressure Differential:	10 000,00 psi
% Swell:	24,07 %





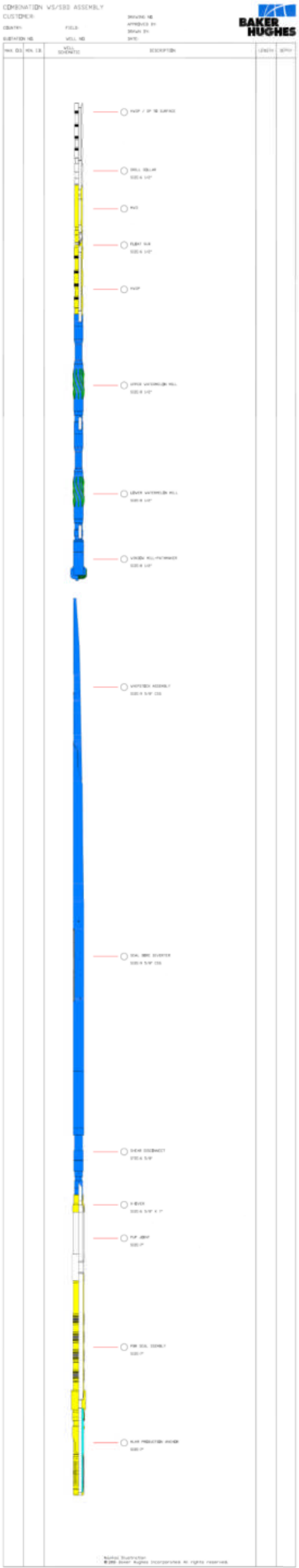
Appendix B

Installation of lower main bore completion

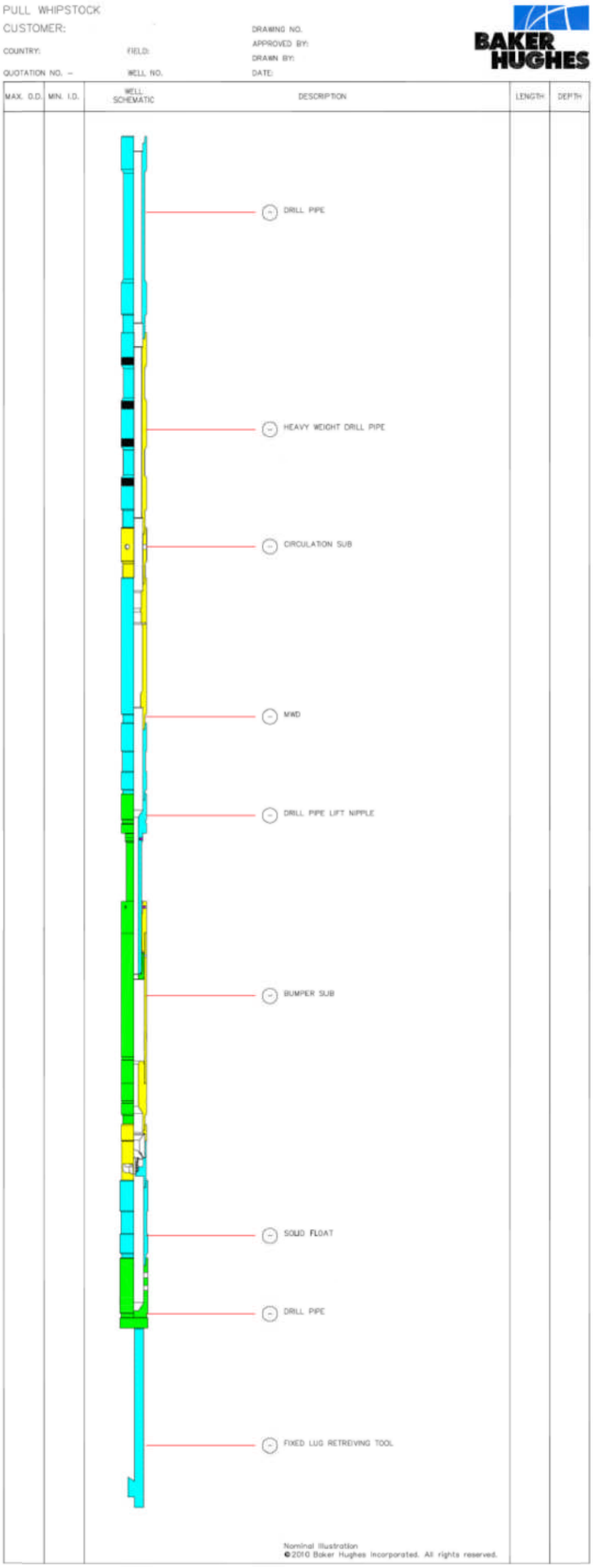


Appendix C

Installation of whipstock and production anchor

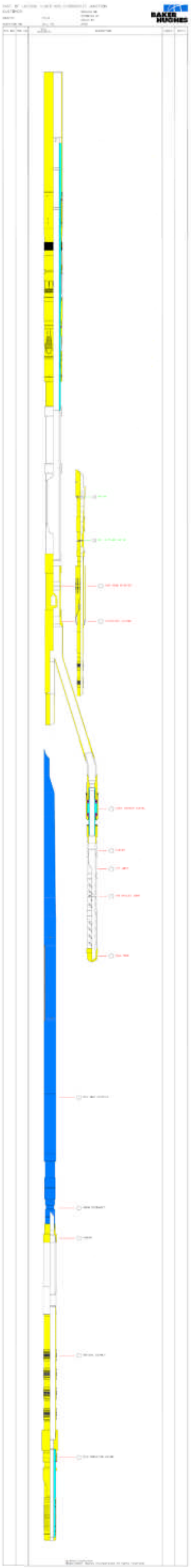


Appendix D
Pull whipstock



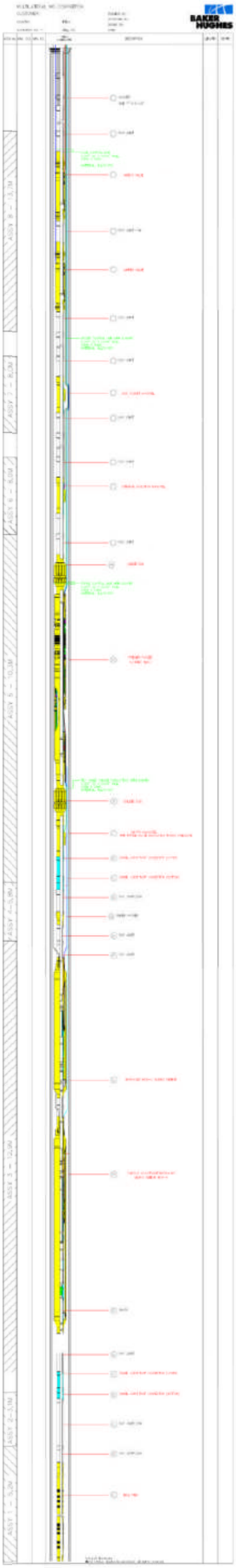
Appendix E

Installation of the lateral liner and junction

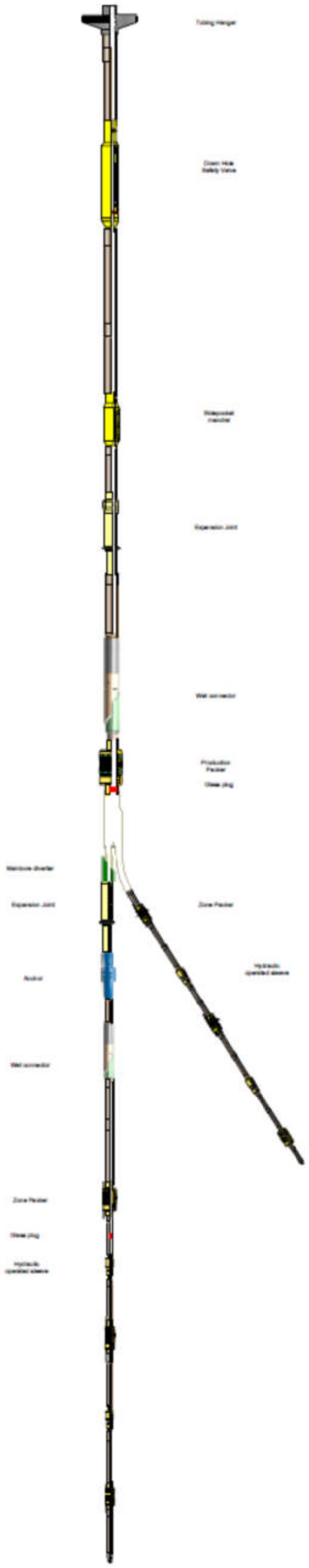


Appendix F

Upper completion



Appendix G
Future solution 1



Appendix H
Future solution 2