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Master Thesis

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"A Rigless Permanent Plug and Abandon Approach"

Emil Mikalsen

Preface

The work of this thesis was performed at Statoil offices at Vestre Svanholmen in Stavanger. I want to thank Statoil for giving me the opportunity to write such an interesting thesis and providing me with a workspace and much knowledge. The subject of the thesis is really relevant for the future of the oil industry and a subject I want to explore even further. Technology is only in the preface and there is a lot of exciting solutions and ideas being introduced the coming years.

The thesis was written for the Statfjord well intervention group and I would like to thank everyone in the whole Statfjord drilling and well department for giving me an excellent introduction and making me feel very welcome. We have had a great fun both in the offices and during team buildings and I am very excited starting to work full time in the same department. Everyone in the department are super positive and provides me with relevant information to all my questions

I would like to send a special thanks to my supervisor Stig Åtland at Statoil for excellent guidance during my work and helping me out with multiple questions. He has contributed to increasing my understanding of the subject in an excellent way and improved the final result of the thesis.

I am grateful to Øystein Arild at IRIS (International research institute of Stavanger) who has been my instructor and contact person to the University of Stavanger. He has made very useful comments during the writing and participated in meetings along the way. I would also thank my Faculty supervisor Kjell Kaare Fjelde for giving excellent lectures in Well completion course and making me interested in well intervention in the first place.

I would also like to thank department manager and leader of the PP&A task force in Statfjord, Tore Weltzin, for including me in the task force and providing me with a lot of useful papers around the whole plug and abandon area. He has also made me think of different possibilities that I might not have come up with myself.

Finally, I would like to thank all my fellow students during these five years at the University of Stavanger for motivation and great social events. We have come really close and I hope to stay in contact with as many as possible of them in the working life coming in the future.

Emil Mikalsen

1. Summary

There are many options to perform a PP&A operation. The goal of this thesis was to look at the opportunities to perform an effective offline PP&A of wells based on cost, time and personnel. After searching through Service Company's solution to the problem the final conclusion became Weatherford and their pulling and jacking unit. Based on time, personnel and cost this unit provides an offline solution plus leaving the drilling rig by itself to perform other well operations simultaneously.

The biggest concern of Statoil is to not have all wells PP&A when production stops at the end of 2016. If operation is still running when the field is no longer producing the average day-rate will increase from 1.1 million NOK to 2.6 million NOK according to calculations performed internal in Statoil. This makes time of performing a PP&A operation the most important number to get as low as possible. A conventional method takes between 45-50 days to finish and 40 days if the conductor does not need to be pulled. This means that if Statoil want to finish PP&A Statfjord A before production stops in 2016 Statoil needs to start PP&A wells in the summer 2012.

In addition to the pulling and jacking unit it is suggested to use a coiled tubing unit to perform cementing operations provides a complete package to a PP&A operation. Cementing on coiled tubing has never been done at Statfjord before and this will be a breakthrough when it comes to PP&A in Statoil. Using coiled tubing to perform cementing job is widely used by other operator company with great success. It is now time for Statoil to also take advantage of the possibilities provided by coiled tubing. Using two units instead of one drilling rig will be a more costly operation, but will provide a much faster and effective operation.

When decommissioning an entire field it is important not to rush, but have a systematically approach to the operation. One of the most important factors to create the most effective abandonment procedure is to have a scheduled plan of the wells plugging order. Separating the wells into batches and starting with the wells not producing and saving the wells actually producing for as long as possible will create an effective decommissioning operation. This may not be the most effective method by logistic, but will provide a stable income during the operations and overall lower the total cost. Based on experience from other fields, such as the Hutton field decommissioning by BP, shows that training of personnel and planning ahead of the operation is very important for the success of the operation. Making the crew personnel familiar with the facilities on the platform and equipment has proven to be of great value.

In addition to suggesting new equipment to perform a PP&A operation this thesis also suggest a new procedure of plugging wells. Many of the steps are similar to the conventional method, but there are two main features to the new procedure. First the 7" tubing and 9 5/8" is cut above the normal pressure zone. Common practice is to cut the tubing a few meters above the production

packer, but cutting it above the normal pressure zone will provide much less pipe handling and a much quicker pulling time. In addition to save time and logistical issues cutting the tubing and 9 5/8" casing above the normal pressure zone will remove the need for a BOP for the rest of the operations. Similar to when drilling a well down to this depth without a BOP, a PP&A operation can be performed without a BOP upward from this point. On Statfjord this normal pressure point is at around 1400m depth.

The basics steps of the new proposed PP&A operation are with these points in mind as followed:

1. Log cement bonding and tubing condition on WL
2. Cut Tubing on WL
3. Displace well to seawater
4. Set cement plug in tubing by CT
5. Pull tubing by PJU
6. Log 9 5/8" casing by WL through PJU
7. Cut casing by WL through PJU
8. Pull casing by PJU
9. Log 13 3/8" casing by WL through PJU
10. Cut casing by WL through PJU
11. Pull casing by PJU
12. Set surface cement plug and pull conductors by CT

Not included in these steps are the setting and pulling of DHSV and mechanical plugs. There is also assumed good cement behind casing showed by each logging run. Contingency plans when cement is inadequate are discussed in the thesis.

1.1 Conclusion

Based on the proposed method and usage of the pulling and jacking unit along with cementing on coiled tubing the following results of time, cost and personnel was established;

1.1.1 Time

Including the pulling of conductor a conventional method require 45-50 days to complete the PP&A operation. Time of the new proposed method is estimated based on history and internal experience and resulting in a total operation time of 28 days. This means that PP&A operations may start in the last quarter of 2012 and still finish early in 2016 with all 40 wells resulting in a massive cost saving for Statoil.

1.1.2 Cost

To calculate the cost of a conventional PP&A method Statoil used historical data and finds an average day-rate to be multiplied with time estimations. This cost estimated day-rate is set to be 1.1 million NOK per day and include all from equipment to personnel. Since the proposed units have never been used before in Statoil the cost calculations for the new method cannot be based upon historical data. Cost calculations have therefore been calculated in details and result showing a day-rate of 2.5 million NOK. This is much higher than the conventional method, but is much more unreliable plus the method takes less time. How much the actual cost will turn out to be is difficult to predict, but as of now the starting point should be 2.5 million NOK per day.

1.1.3 Personnel

A normal rig crew working on the drilling rig consists approximately of 35 people. The new proposed method requires only 18 people. This is half of the people required by the conventional method and will create a daily saving of approximately 250 000 NOK per day. During the whole PP&A campaign this will result in major cost savings overall.

1.2 Summary table

	Conventional method	**New method**
Personnel	*35 people*	*18 people*
Time	*45-50 days*	*28-30 days*
Cost	*1.1 million NOK/d*	*2.5 million NOK/d*

Table 1: *Comparison conventional vs. new method*

List of Contents

2. List of figures

3. List of Tables

4. Introduction

In 1969 ConocoPhillips discovered the Ekofisk oilfield in the North Sea. This started the golden area of the Norwegian oil industry and soon after more and more major oilfields was discovered all over the Norwegian continental shelf. The biggest of them all was found by US Mobile and later operated by Statoil. This field was named Statfjord. During the years Statfjord developed to become the biggest contributor to the Norwegian economy and a worldwide known field. Statfjords major productivity and skillful personnel kept Statfjord at its position as the highest productive oilfield in Europe (except Russia) and still holds the record of highest daily production of oil.

During the 1970's and 1980's a huge amount of wells was drilled all over the North Sea. Only in Statfjord over 40 wells was drilled either as a production or injection well. Unfortunately the production will not last forever. Production has gradually decreased while more and more water is being produced. While Statfjord as a field is planned to produce until year 2030 Statfjord A, which was the first of three platforms on Statfjord field, is planned to cease production at the end of 2016. By this time all wells needs to be permanently plugged and abandoned (PP&A). As the procedure is performed today a typical PP&A operation takes around 40 days. This means that for Statoil to reach the goal to PP&A all the wells until the end of 2016, operations needs to start as soon as possible. As Benjamin Franklin once wrote "Time is money" and these words truly reins the petroleum world. High rig cost and crew makes every second count in the companies search and production of the "black gold".

Another option is therefore to look at the procedure of how the wells are being PP&A. This thesis will take a closer look upon the procedure in a PP&A operation and try to suggest a more time and cost efficient method. As the procedure is performed today the drilling rig is used for most of the tasks in a PP&A job. Not only is this an expensive operation, but it also occupies the drilling rig which could be used for other intervention or drilling tasks. One of the solutions this thesis will take a closer look upon is to see if more of the tasks performed these days by the drilling rig can be performed either by wireline or coiled tubing. Not only will wireline or coiled tubing provide a less expensive operation, but a lot of hours can be saved from tripping in and out of hole versus drilling rig.

Most important is the safety of the operation and to ensure that the finished operation has been performed according to safety regulations such as NORSOK and APOS. A well needs to be plugged with two barriers, one primary and one secondary. These barriers are presented in a well barrier schematic (WBS). APOS, which is Statoil's internal requirements, has a stricter WBS than the standard national NORSOK requirement. In this thesis a closer look upon the strict requirements in APOS will be taken and maybe a proposition of reducing the gap between APOS and NORSOK will be proposed.

The thesis starts with an introduction to Statfjords history and a more detailed plan of the coming years. Next is a short theory part where basic wireline and coiled tubing information is introduced. This information includes topside and downside equipment and a short brief of which work area they are common to be used in. In the last part of the theory is the NORSOK and APOS requirements presented more in detail. Description of primary and secondary well barriers and length requirements is described along with cement and barrier lengths to fulfill APOS requirements.

The next chapter is the main scope of the thesis. First an introduction of a conventional PP&A operation is described. Then the thesis will take a closer look upon the global experience to see what other solutions during a PP&A operation different companies are using. In this section a presentation of each service company and their inventory of equipment are also presented along with contact person of the company. After this a proposal of a new method of doing PP&A is presented using a specific Statfjord A well. Comparison between the conventional operation and the new approach is illustrated for time, cost and personnel. Further research and development needs are then suggested to make the procedure even more efficient in the future.

Finally a conclusion sums up the proposed ideas with limitations, challenges and benefits along with a comparison of cost and time savings for each well. At last recommendations for further work is suggested and a proposition of how to design a well to make it easy accessible for intervention tasks.

4.1 Main Targets:

- Find the most cost and time efficient procedure for a PP&A operation?
- What procedures can be performed without the need of rig?
- Are APOS requirements to strict?
- How should wells be designed in the future to ensure an easy, safe and efficient P&A operation?

5. Statfjord field

5.1 History:

Statfjord has been the leading oilfield on the Norwegian continental shelf throughout its production life. The field was discovered by US company Mobil in 1974, which makes Statfjord one of the oldest oil fields in the North Sea. On January 1st 1987 Statoil took over as operator of the field and has lead the production from then. The field consists of three condeep concrete platforms, Statfjord A, B and C. As table 2 shows, Statfjord A was the first built and started production in 1979. Soon after, in 1982, Statfjord B began its production followed up by Statfjord C in 1985. [16]

Statfjord is the largest oil discovery in the North Sea and has from production start produced values over 1 050 billion NOK [2]. When production was at its best, Statfjord produced over 700 000 barrels of oil per day. On January 16, 1987 they set the European record (without Russia) for the highest daily production with a total of 850 204 barrels of oil and gas. This record still stands firm today [17].

Statfjord is found in the Tampen area in the northern part of the North Sea and approximately 15% of the field fact stretches over to the UK continental shelf.
The field is about 2.5 miles wide and 15.5 miles in length. The sandstone reservoir containing hydrocarbons are found at a depth of 2500-3000 meters [17].

The oil produced is pumped into the storage cells and transported straight to the refinery onshore by boats. The gas however is transported through the subsea pipeline, Statpipe and Tampen Link (figure 2), ending up at the gas facilities at Kårstø where they are transported to Emden, Germany.

Statfjord A
Weight: 600 000 tons Height: 270 meter Living quarters: 206 beds Production start: 24.11.1979 Storage cell capacity: 1,3 billion oil barrels Max prod. capacity: 300 000 b/d
Statfjord B
Weight: 816 000 tons Height: 271 meter Living quarters: 228 beds Production start: 05.11.1982 Storage cell capacity: 1,9 billion oil barrels Max prod. capacity: 180 000 b/d
Statfjord C
Weight: 643 700 tons Height: 290 meter Living quarters: 345 beds Production start: 02.06.1985 Storage cell capacity: 1,9 billion oil barrels Max prod. capacity: 210 000 b/d

Table 2: *Statfjord platform* [16]

5.2 Status and future plans:

For each day that go, oil reserves in Statfjord are reducing. But even though production is well over 60% of the IOIP (initial oil in place) Statfjord still have some years left. New strategies, such as gas lift and water injection has been implemented to raise the recovery rate. Now the estimate is to recover 66% of the IOIP, making Statfjord produce for another 15 years [18].

Company Name	Share [%]
Statoil AS	44,34
ExxonMobil AS	21,38
ConocoPhillips AS	10,33
Centrica Limited	9,69
Centrica AS	9,44
ConocoPhillips Limited	4,84

Table 3: *Statfjord partners*

One of Statoil's strategies for getting the most values out of Statfjord is by engaging the late life plan. This strategy aims to turn Statfjord from an oilfield with associated gas to a gas field with associated oil. This is accomplished by reducing the pressure both in the reservoir and the platform and produces the previously large gas volumes injected. By this strategy, the gas recovery will rise from a previous estimate of 54% to a new estimate of 71%.

To make the recovery of IOIP and IGIP as high as 66% and 71% multiple wells needs to be plugged and sidetracks drilled. Statfjord A contains 42 wells and has an estimated shutdown in 2016. This is where the intervention makes its biggest contribution and the area this thesis will focus on the most. Today a PP&A operation is estimated to take around 40 days from start to finish. This requires strategy planning for PP&A to start as soon as possible to avoid going too far beyond the estimated shutdown date. When all wells are not producing anymore, rig day cost may double in size and cause Statoil to lose a lot of unnecessary funds. It is therefore very important to look at all possibilities to perform the most effective P&A operation as possible with regards to time, crew and safety [18].

5.3 Geology:

The geology containing hydrocarbons in Statfjord was developed during the law period in the mesozoikum area about 150 million years ago. The reservoir can be seen in figure 1 and containing Brent group, Rogaland formation and Statfjord formation and produces from a depth of 2500 – 3000 m MD. The Statfjord formation is positioned at the deepest depth and is producing from water and gas injection. On top of Statfjord formation is the Brent formation. The Brent formation

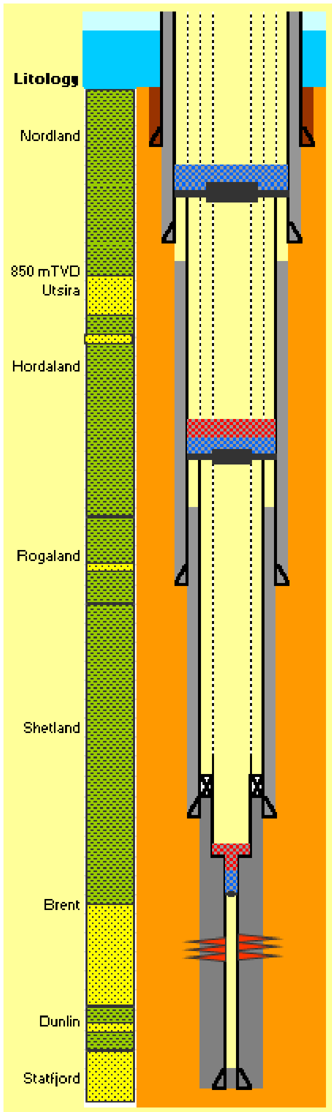


Figure 1: *Statfjord geology* [13]

stretches into British territory and a lot of wells on British sector are producing from different part of this formation. Also in this formation is water and gas injection introduced to maintain an effective production. Since both Statfjord and Brent formation is situated so close to each other they can during a PP&A operation is planned as one big reservoir. This means they can shear both the primary and secondary barrier element. At shallower depth is the Rogaland GP where the Lista formation is found at a depth of 1830m TVD. The Lista formation has a small inflow potential of hydrocarbons of 0.4 mD and requirements then says it has to have two barriers.

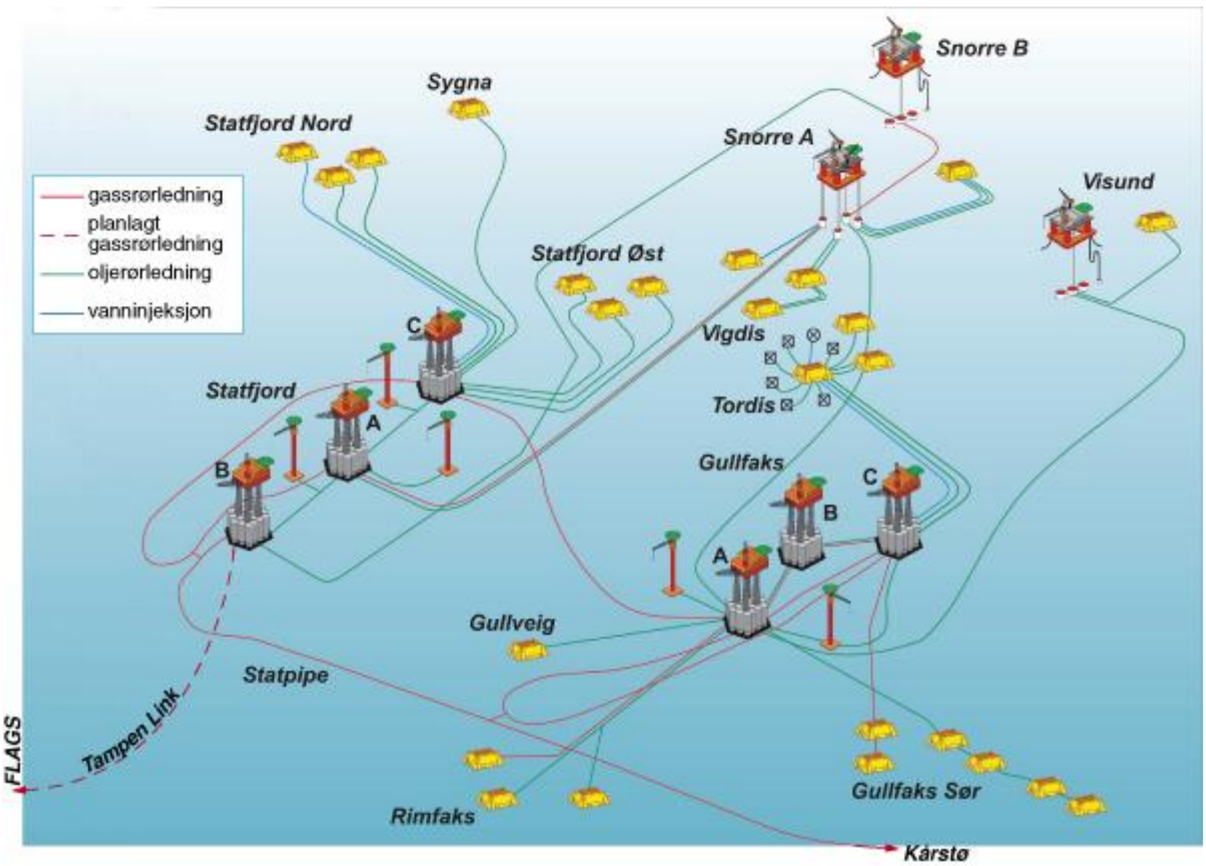


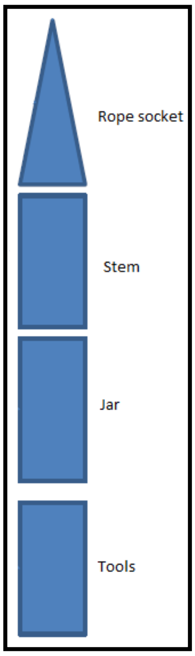
Figure 2: *Overview of Statfjord platform with pipelines [15]*

6. Wireline

Wireline is described as a cabling technology to lower equipment or measurement devices into a well to perform an intervention task [1]. It is the most common technology used when performing simple intervention tasks that do not require too much force. Since wireline is versatile and easy to set up, it is being used in many different operations. Scale removing, bailing sand, remove wax, setting and retrieving plug/valve, fishing, perforating, etc. is just some of its operating areas.

A wireline system is a complex engineering design. The system can be divided into two separate areas. First is the toolstring at the bottom which consists of components going down into the well to perform the intervention job. The second part is the surface equipment to maintain well control and to make sure the operation runs smooth and safely.

A wireline toolstring consist of many different parts as shown in figure 3, from top to bottom:



Rope socket – This is the top component of the toolstring and act as a connection point between the toolstring and the wire. There is usually installed a weak point in the rope socket so that the string will be easy to fish up if the cable should snap.

Stem weights – Stem weights is installed on the toolstring simply just to add more weight to overcome the well pressure or to help with jarring operations.

Jars – A jar is almost like a hammer. It can be extended and closed rapidly to induce a mechanical shock to the toolstring either upwards or downwards.

Different tools – At the bottom of the string is the actual tool needed for the operation. This can be a running tool, pulling tool, gauge cutter, bailer, etc.

Figure 3: *Wireline toolstring [1]*

At the surface there are many tools to make the operation go smooth and safe. A winch with a depth and weight indicator safely controls the cable down the hole. The wireline operation is usually carried out by positive wellhead pressure. The required pressure controlling equipment is therefore installed on top of the x-mas tree and consists of the following elements, from x-mas tree and up as shown in figure 4 [1]:

BOP – The BOP is a secondary barrier and has one ram that can close across the slick line at closed in conditions. It is being used when there is a leakage or when maintenance has to be performed in the pressure sealing components above the BOP.

Lubricator – A steel pipe installed on top of the BOP [1]. Its purpose is to lubricate the tool string into the pressurized well. It also works as a seal during pressurization [19].

Tool catcher – If the wireline tools need to be forced into the top of the lubricator, the head catcher has the task to clamp on and hold the linehead so it does not fall down in the well if the line fails. The tool is released when pressure is equalized.

Chemical injection sub – Designed to allow injection of chemicals to either de-ice or prevent corrosion. It also has a felt packing that is kept constantly wet, allowing the packers to act as wipers to the wireline passing through it.

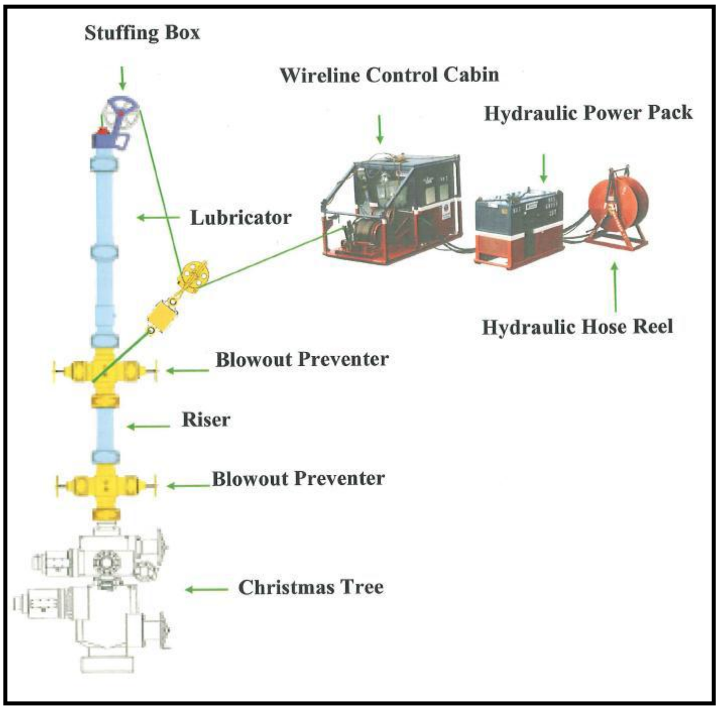


Figure 4: *Surface wireline equipment [1]*

Stuffing box – This element consist of rubber elements sealing around the slickline making this a primary barrier. These rubbers are forced together by the wellhead and if needed, additional hydraulic pressure can be applied.

Grease injection head – Inside the grease injector head there are a number of flowtubes that the cable runs through. Inside the flowtube, grease is continuously pumped around the cable with an injection pressure 70 bars larger than the well pressure [2].

A wireline system has two separate cable systems, slickline and braided line.

The slickline is used for mechanical operations and has a typical size of 0,108” or 0,125”. It is commonly used in the production tubing and often includes a jar to create upward and downward forces when doing operations. [19]

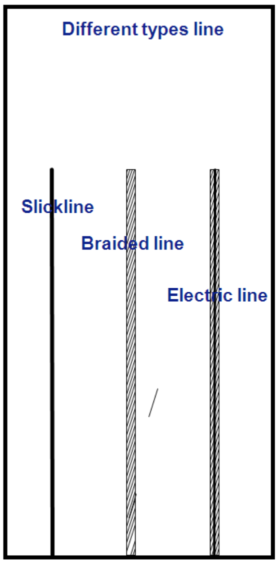


Figure 5: *Slickline variations [2]*

There are two types of braided line, with and without electric cable. The one without electric cable is often used for heavier fishing operations where the slickline has insufficient strength.
The electric cable is used for tractor applications and logging tasks. Braided line and slickline has

almost the same surface equipment. The main thing separating them is that slickline operates with stuffing box while the braided line has a grease injection head on topside. [2]

6.1 Well tractor

When highly deviated wells became more and more common a natural problem occurred in the work of well interventions. The problem was based upon how to reach the wanted MD without getting stuck from friction caused by gravitation. This usually happens from around 65^{o} inclination. Since the only thing to overcome the friction was the weight of the string, coiled tubing or snubbing was the most common things to use. These are much more expensive operations than wireline and the industry eagered for new technology to be developed. The answer was the development of a well tractor.

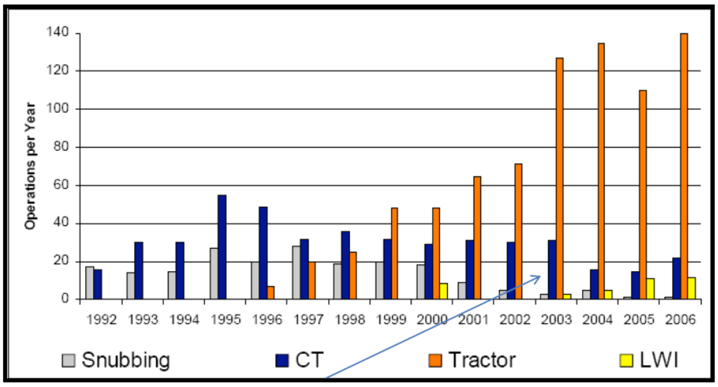


Figure 6: *Well intervention solutions* [2]

A well tractor is an extra tool mounted on the toolstring, when inclination is too big (over 65^{0}). It can be installed in the back of toolstring as well as in the front. Usually it is placed in the back to make it easier to push the toolstring forward. Its main equipment is the wheels that are pushed out to create traction with either the casing or the borehole wall. An electric motor drives a hydraulic pump, making the wheels to rotate. This is why a tractor needs to be runned with a braided electric cable. Aker Well Solutions are one of the providers of a well tractor. From the figure 6 it clearly states that the invention of the tractor was much needed in intervention operations.

There are some advantages of using a well tractor. It is very quick to rig up, it is a light equipment and all standard wireline equipment can be used alongside with it. The challenges mostly concern around scale deposits, damaged tubing and electric signal transferring.

Since wireline is so cost effective and easy to rig up, it is the most preferred intervention method. Huge numbers can be saved on Statfjord and other Statoil fields if wireline can contribute more in the P&A operations than it does today.

7. Coiled tubing:

Coiled tubing is defined as “any continuously-milled tubular product manufactured in lengths that require spooling onto a take-up reel, during the primary milling or manufacturing process” [20]. Coiled tubing was initially developed to perform remedial work on live wells [3].

The history of coiled tubing goes back to the early 1960’s, and during development over many years, coiled tubing has become an important component of many well service and workover applications. Development of coiled tubing is still ongoing and even though well service/workover activities stands for approximately 75% of the coiled tubing usage, areas such as drilling and completion uses coiled tubing more and more in their operations.[20] In the beginning, manufacturing limitations caused the coiled tubing to be limited to small diameters and short string lengths. These short string lengths of around 250 ft. were used to make longer strings connected by butt welding. The many butt welds resulted in numerous string failures and better methods needed to be developed. Today, welding techniques has improved and the need for butt welds is no longer there, allowing the CT string to be milled continuously [3].

The major elements of a coiled tubing unit are powered by hydraulic power generated from a hydraulic control system located in the power pack.

Figure 7: *Modern coiled tubing unit on land [20]*

7.1 Elements of a coiled tubing unit

CT power pack - The power pack is usually driven by diesel and provides hydraulic power through a system of pumps, valves and lines. This hydraulic power drives hydraulic pumps, which supply each circuit with the pressure and flow rate required to power an element in the coiled tubing unit.

Ct control system - The control system is located inside the control cabin where the operator controls the elements of the coiled tubing. This console also provides gauges for monitoring and recording the operating parameters, such as wellhead pressure, circulation pressure and tubing weight and depth.

Injector head – The injector head provides the main access to the well for the tubing string. It incorporates a special chain assembly to grip the string and has a hydraulic system that provides the tractive effort for running and retrieving the string from the wellbore. The injector head is found between the lubricator and the BOP. The lubricator feeds the tubing string from the reel, around a controlled radius and into the injector head. To get a good and secure connection to the BOP, a stripper is mounted beneath the injector head.

Tubing Reel – The tubing reel is used for storage and transportation of the coiled tubing. During operations the string runs in and out of the reel with the help from a hydraulic motor.

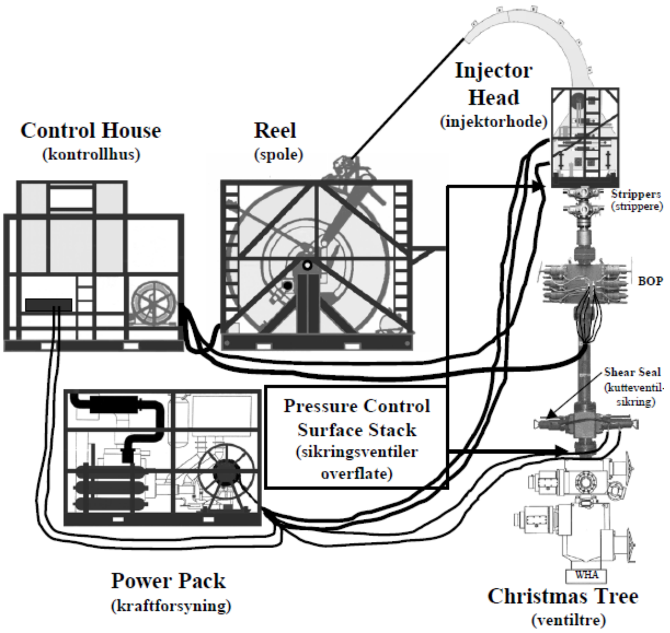


Figure 8: *Coiled tubing rig-up equipment [4]*

A key component when running a coiled tubing operation is to have good well control. This is achieved by the BOP and the stripper. The stripper may also be referred to as a packoff or stuffing box and provides an operational seal between the pressurized wellbore and the surface. The BOP is situated beneath the stripper. Unlike the common BOP used for well control, a coiled tubing operation requires a special coiled tubing BOP. The CT BOP consists of several rams, each with its own function. The number of rams can vary from single, double or quad system depending on its configurations. The quad system is the most common and consists from top to bottom of [1]:

- Blind ram - Seals the wellbore when the coiled tubing is out of the BOP
- Shear ram - Used to cut the coiled tubing
- Slip ram - Hold the coiled tubing weight and prevents it from falling if it's being cut. Some slip rams work both ways and also prevents the coiled tubing from moving upwards.
- Pipe ram - Provides a seal around the hanging coiled tubing.

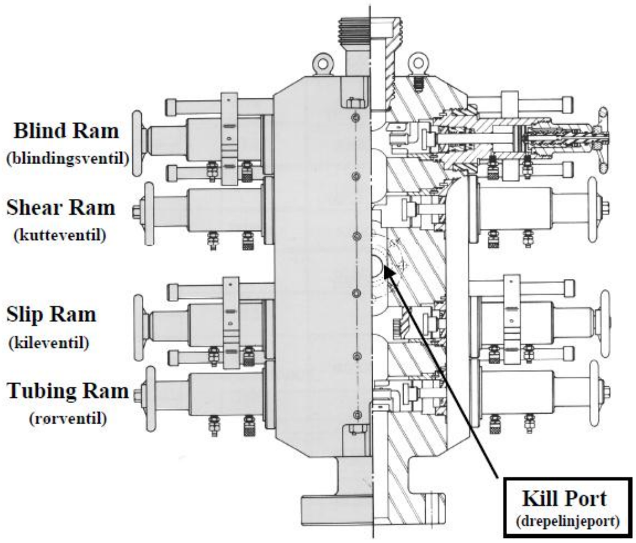


Figure 9: *Coiled tubing BOP ram-setup [4]*

The initial purpose for developing coiled tubing was the desire to be able to do work on live wellbores. But as the years have gone by there has become many other advantages by using coiled tubing for intervention operations. Speed and economy is now the key advantages for applying coiled tubing. Time spent on rig-up and trip time is far lower for CT than if the same operation should be performed by the rig itself. Coiled tubing also takes up less deck space and requires fewer personnel than a rig operation. Not only will the cost go down, but multiple operations can be performed simultaneously when the rig is free to perform its own operations.

Where wireline is even faster to rig up than coiled tubing, coiled tubing offers a more powerful solution when the well operation requires much force. One of the main features of coiled tubing is that it offers the possibility to circulate the well during operations. If it is possible to plug the well with cement using coiled tubing, tremendous cost may be saved. This is one of the possibilities this thesis takes a closer look upon. In table 4 below it shows a summary of the similarities and differences between wireline and coiled tubing. Also an overview of the advantages and challenges of the two methods versus drilling rig is summarized.

7.2 *Wireline vs. Coiled tubing*

Similarities	• No need for rig assistance • Operational area: Perforation, set/pull plug, logging & fishing • Logging while operating • Require little deck space
Differences	• CT is able to circulate while operating (produce & place cement) • WL BOP an CT BOP • WL uses tractor in high inclination wells • Operational area: CT is able to place cement, CT is used for well stimulation and WL is more used for well cleaning • Medium/heavy operation = CT, Light operation = WL
Advantages vs. Rig	• Small rig-up time • Cheap and simple • Rig can perform simultaneously tasks on other wells • RIH/POOH time is reduced drastically • Require fewer personnel
Challenges vs. Rig	• Push/Pull forces • Getting stuck • Pressure control equipment • Heavy force operations • Cementing, small diameter of CT makes it difficult to place large amount of cement in hole. Needs to be careful not to get stuck.

Table 4: *Wireline & Coiled tubing summary*

8. Definition of permanent P&A

Statfjord is an old oilfield and needs to undergo many intervention tasks to adapt to Statoil's late life plan. Especially Statfjord A with an estimated shutdown during the end of year 2016, operations to permanent plug and abandon (PP&A) has to start as soon as possible. A PP&A operation is executed with the intention of never re-open or produce from that section again. It is therefore important to have an eternal perspective when choosing the equipment and barrier drawing for the job. The equipment used to plug the well needs to withstand any foreseeable chemical and geological processes that may happen in the future [5].

The success of the PP&A operation depends on this long term sealing ability. Norwegian law states that the owner or last operating company is responsible for all costs in permanently abandoning a well and to ensure that the PP&A follow NORSOK D-010 requirements. In the North Sea it is very critical that the operation is a success concerning the very high cost of operating offshore. Risked cost of returning to a leaky well will be millions of NOK. Environmental issues, like oil spill etc., would not only hurt the company's reputation, but add a unnecessary cost that should be easy to avoid in the first place[6].

8.1 Plugging requirements

NORSOK D-010 is a guideline developed by the Norwegian petroleum safety authorities with minimum requirements for operations such as PP&A. In Statoil these regulations have been further developed to be even more stringent. The requirements are illustrated in a well barrier schematic (WBS) (See appendix B) that describes which elements are the primary and secondary barrier elements. When deciding on how many barriers that actually is needed, four criteria need to be considered:

- Is the abandonment permanent or temporary?
- Is the formation permeable or impermeable?
- Is the formation over overpressured or normal pressured?
- Is the reservoir exposed, so that hydrocarbons are present?

When performing a permanent abandonment it is required two barriers when the reservoir consists of:

- Permeable formation with overpressure, or
- Permeable formation with hydrocarbons

But in some situations it is sufficient with only one barrier:

- Impermeable formation with overpressure

- Permeable formation with normal pressure (or less) [42]

This installation of barriers is called plugging of well. Usually it is performed by placing a cement plug over the reservoir and up to the casing creating a safety barrier envelope with pressure integrity intact. The minimum requirements for the Norwegian continental shelf are described in NORSOK D-010, but Statoil has made some changes to make it even safer. These changes pretty much consist of length of plug and how to do a proper verification that the plug functions as a proper well barrier.

To determine at which depths the well barriers should be placed it was common practice for some years ago to use the fracture gradient from a leak-off test or a formation integrity test. Today the current method is to use the minimum formation stress (FCP) achieved from an extended leak-off test (See Figure 10). FCP is described as the pressure where the fracture will close. In Statoil a primary and secondary barrier shall be placed at a depth where minimum formation stress is higher than the potential pressure below. For an open hole to surface completions, the barrier element shall be placed as deep as possible in the casing and with the cement top minimum 50m above the shallowest permeable zone.

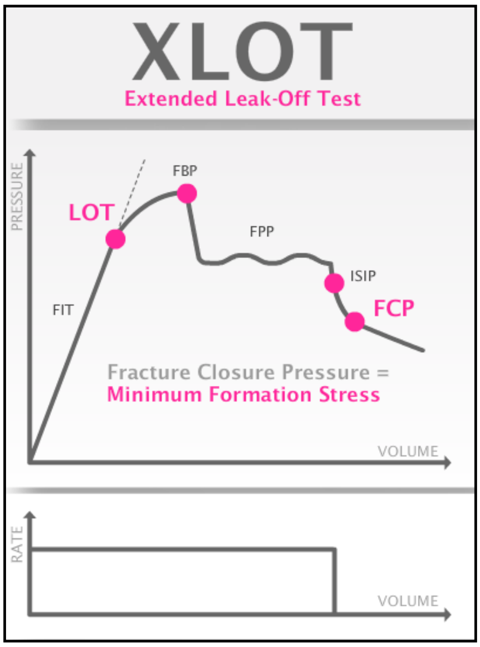


Figure 10: *Extended leak-off test [42]*

To qualify as a permanent well barrier element, the element must have these following properties: [42]

- Impermeable
- Long term integrity
- Non-shrinking
- Ductile – able to withstand mechanical loads/impact
- Resistance to chemicals/substances
- Wetting – ensure bonding to steel

There are only two permanent barriers being used in Statoil today, cement and shale formation. Cement is not an optimal solution concerning ductile and non-shrinking issues, but it is the best most reliable and cheapest available material on the market. Other materials are being researched and are under evaluation, see chapter 10. Statoil is a pioneer in Norway in the use of bonded shale as a barrier element. The shale formation creates a barrier in the annulus between the casing and the borehole wall. For the shale to be approved as a barrier element two important requirements needs to be fulfilled: [42]

- Location of the formation, minimum 50m continuous length of formation with 360^0 of bonding throughout.

- Sealing ability of the shale

This information needs to be gathered by two independent logging tools and a leak test is performed over and under the shale formation.

It is important to keep in mind that even though a reservoir is PP&A according to NORSOK D-010, a well is only temporary abandoned until the wellhead is removed.

8.2 Statoil well barrier requirements [43]

When installing a barrier, the barrier must fulfill four criteria to successfully pass as a installed permanent barrier; Length, cross-section, positioning and verification.

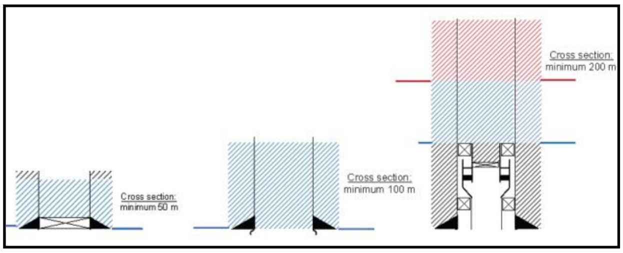


Figure 11: *Barrier length requirement [43]*

Length: The length of a cement plug must be either 50m or 100m, depending on the foundation of the plug. If there is a mechanical plug as a base, the cement plug must be at least 50m. If there is no plug as base the cement plug must be 100m long. If the annulus casing cement functions as primary and secondary barriers the length must be 200m, 100m as a primary barrier and 100m as a secondary barrier. This is illustrated in figure 11.

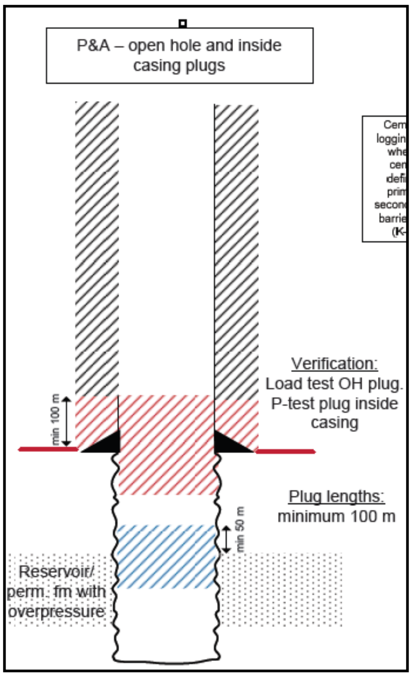


Figure 12: *Open hole cement barrier* [43]

One issue at Statfjord A is that the cement behind the casing is not a very good foundation. To achieve a good foundation it is normal to mill a section, wash and squeeze cement. This is a time consuming and costly operations. Luckily new methods are available and are mentioned in chapter 10. There is no standard completion package on Statfjord, each well has its own completion and intervention program needs to be individually made. According to NORSOK D-010 an open hole cement job requires a 100m cement plug, and at least 50m must extend above the source of inflow. If the open hole cement plug extends into a casing, the cement plug should at least extend 50m into the casing. Although in Statoil it is preferred to extend it 100m over the casing, because it can be difficult to get a good pressure test when you have shorter length. As shown in figure 12.

Cross section: The barrier must extend to the full cross section of the well and include all annuli and seal both vertical and horizontal.

Position: The well barrier must be placed at a depth with sufficient formation integrity. As mentioned earlier this is found by an extended leak of test. It is normal to place the barrier as close to the source of inflow as possible, although there is one exception. For an open hole with surface barrier where the exposed zone are documented as impermeable the base of the barrier does not has to be at a depth with sufficient formation strength.

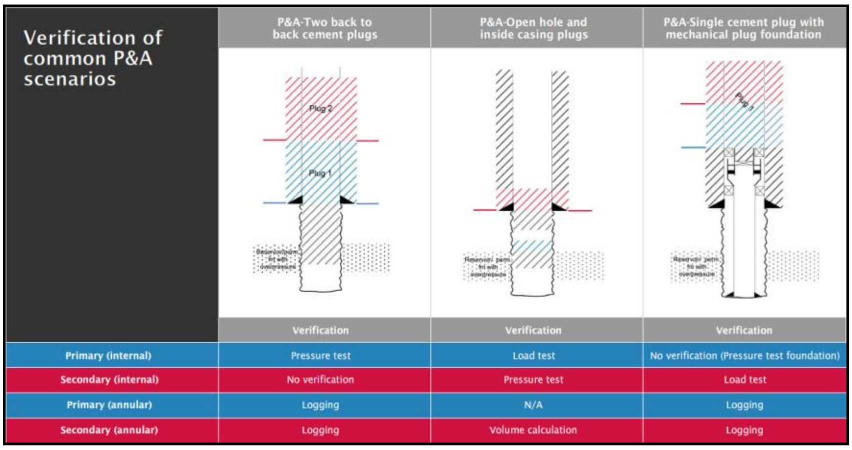


Figure 13: *Well barrier verification* [43]

Verification: Verification of well barriers in Statoil happens through logging, pressure test or load testing as showed in figure 13. Logging is necessary when the same cement job defines primary and secondary barrier in the casing annulus. Logging ensures that the cement job fulfill all the above requirements. A pressure test with 70 bar over the fracture gradient verifies the integrity of the barriers installed. When performing a pressure test it is important that the pressure exceeds the formation strength in the direction of flow. This ensures that it is the barrier that is holding the pressure and not the formation. If the pressure test is performed on a surface plug it is sufficient with 35 bar over fracture pressure. If it cannot be done by pressure test, a load test with 10 tons will be performed.

As mentioned earlier some Statfjord wells will be PP&A and a sidetrack well will be drilled in the same slot to keep up with Statfjord late life plan. This is called a slot recovery. A Slot recovery is when the upper section of an older well is reused to drill after new reserves. The lower section is permanently abandoned. During a slot recovery operation the casing is milled and a new hole is drilled from the opening in casing using a whipstock and cement plug. In this case one well barrier can be shared and function as a barrier for more than one wellbore.

Statoil requirements and NORSOK D-010 are quite similar, but in recent times Statoil's interpretation of NORSOK has become debatable. In the 1st and 2nd quarter of 2012 NORSOK D-010 is under revision and clarification around important P&A issues is one of the main discussions. Important issues regarding Statoil's interpretation is:

- To calculate the setting depth for a plug, Statoil uses minimum horizontal stress while NORSOK uses formation strength. If the formation stress is read as fracture pressure this will be a more conservative interpretation than the minimum horizontal stress.
- NORSOK defines a PP&A to be eternal, but it does not state how long eternal actually is. The eternal perspective role is important when calculating the reservoir ability to re-charge. If the initial reservoir pressure was 350 bar and sunk to 200 bar when production was finished

and the reservoir abandoned. What will then be the reservoir pressure 200-600 years from now? Or even further? The eternal perspective is interpreted in Statoil to be around 500 years.

- Statoil's limit for inflow potential is 0.1 mD. Following is Rogaland GP and Lista fm in the category that requires two barriers. The NORSOK requirements are debatable and how the inflow potential is defined may reduce the barrier requirement from one to two.

9. Conventional P&A activities on WL/CT

This chapter will introduce activities performed by wireline, coiled tubing and rig during a conventional PP&A operation. The potential of reducing cost is very high if just a few more tasks can be performed without the help of the rig. To achieve a more cost effective PP&A operation maybe even the whole conventional method of PP&A has to be changed.

Before the PP&A operation start, the well needs to be prepared. This preparation is performed using a wireline system. A deep set mechanical plug is set at the top of the reservoir to plug the tubing. The plug is then pressure tested according to APOS standard. Next the tubing is punched using wireline. This is performed to check if there is communication between the tubing and A-annulus. If there is no communication the well cannot be displaced to water, but retain with heavier brine in the tubing/casing. When the well has been displaced to water a DHSV is installed and pressure tested according to APOS standard. If the pressure test of the DHSV is insufficient, another option is to place a shallow mechanical plug minimum 50mMD below seabed. The well is now prepared safely according to APOS standard with barriers intact (see appendix G) and PP&A operation is ready to begin.

While all of the preparations are performed by wireline it is now time to use the rig for the upcoming heavier tasks. To make the rig able to work securely the x-mas tree needs to be nippled-down and replaced by nippling-up BOP and riser. The rig is then used to cut and pull the tubing above the production packer and afterward set a cement plug in the 7” liner on top of the mechanical plug. The reservoir is now sealed off and work continues with the next section of the well. This involves cutting the $9^{5/8}$” casing and pull it out of the hole. After the $9^{5/8}$” is POOH a cleanout run of the 13 $^{3/8}$” casing is executed. This is a good procedure since the next task is to run a USIT-CBL to verify the cement quality behind the casing. The cleaning ensures a correct and valid logging run. After the logging is finished and the cement behind casing is validated, an EZSV is set on top of the remainings of the $9^{5/8}$” casing and pressure tested according to APOS. The cleanout process and running of USIT-CBL is performed by wireline through the drilling rig. This ensures a faster RIH and POOH time. The EZSV is usually set with pipe. When the EZSV is in place and pressure tested, a cement plug is set in the $13^{3/8}$” on top of the EZSV. According to NORSOK D-010 the well now has two barriers, but the well is not finalized yet. The $13^{3/8}$” casing is cut and POOH at a depth depending on the USIT-CBL interpretation. A new cleanout run is then performed in the 20” section before a new EZSV is installed in the 20”casing and pressure tested. The last cement plug, approximately 50m according to APOS, is then placed on top of this EZSV to create a final barrier against the reservoir. The well is now completely secure and the final step is just to displace the remainings of the well with seawater, nipple-down the BOP and install cover. The well consist now of all mandatory parameters (see appendix B) [7].

This procedure is taken from PP&A of well A-36 on Statfjord. It shows a very easy and step by step conventional PP&A procedure performed by Statoil nowadays. From the procedure it clearly shows that the rig is used during most of the PP&A operations. It is also clear that coiled tubing is not used much during the PP&A operation. One reason for this is that coiled tubing in some cases struggles to overcome the push/pull forces in the well. But, according to Statoil document 25 wells have the option to run coiled tubing, 13 do not have the option and 2 is currently unknown status to run coiled tubing. This may indicate that Statoil has been a bit too conservative in their method of choices and perhaps it is time to start thinking in a more open and wider perspective. The next chapter will look further into the opportunities with coiled tubing and present global experience where coiled tubing and other techniques are used for cementing, cut and pull tubing etc.

10. Global experience

This chapter will encompass different methods of PP&A operations performed worldwide in recent years. The focus has been on using the rig as little as possible to have the most cost effective operation. Worldwide mean that different region well control requirement of PP&A are represented and maybe not all methods live up to the requirements defined in NORSOK D-010.

10.1 Oman:

A more cost effective approach to PP&A of wells is a worldwide concern of all oil companies. One of the things that are consistent in their approach of a better PP&A method is the opportunity to leave the production tubing and casing in the well. In Oman the Petroleum department of Oman (PDO) and Schlumberger performed a 60 well case study [1] to find a good method to cost effective PP&A a well. The wells where over 25 years old and had the reservoir in a sandstone environment. This is very similar to Statfjord. One of the key features in this study was to reject the previously used Portland cement and instead use an advanced, flexible & expanding cement. Since the cement was expanding it provided excellent bonding with the cement and no micro annuli between the casing and cement was detected. The other main thing from this PP&A operation is that they chose to leave the tubing and casing behind in the well. The operation started with preparing the well to be PP&A. This included cleaning the production tubing and annulus with fluid containing surfactants and acids. The cleaning process is very important to avoid the previously mentioned micro annuli. After this the well was displaced to salt brine. Next a bentonite spacer was displaced to the bottom of the well to act as a base for the cement plug. The well was then perforated above the spacer. The first cement plug was set across the perforation and then a second cement plug was set opposite the 13 $^{3/8}$" casing shoe on top of a bridge plug in the production tubing. A multistring perforation of the production tubing and 9$^{5/8}$" casing were performed and a wall to wall cement plug was placed in the casing. At last a bridge plug was set on shallow depth and the last cement plug was placed on top to finalize the plugging of the well [8].

Throughout the whole operation all tasks including cementing and setting bridge plug was performed by a coiled tubing unit. Since the tubing and casings are left behind in the well no rig was needed for this abandonment. All in all this operation took only five days and saved 30-40% of previous abandonment campaigns with drilling rig [8].

One of the major concerns of applying this method to a North Sea well is to verify the cement bonding and height behind the casing and liner. According to NORSOK D-010 it is accepted to use logging data of cement behind casing taken when the well was drilled. But Statoil has its own more strict guidelines that request an azimuthal real time data log of the cement behind the casing. This is a major challenge to overcome unless logging cement through multiple casings is available. In Statfjord the cement job on liners is not documented as needed and a cement plug cannot be placed unless more logging is performed. If the cement plug cannot be set in the liner it needs to be placed in the $9^{5/8}$" casing. This requires pulling the entire tubing. The case study in Oman is very interesting if it can be applied in the North Sea because it has many advantages along with some challenges:

<u>Advantages:</u>

- No drilling rig needed, cost saving.
- Tripping speed with coiled tubing is far greater than a drilling rig, time saving.
- Some of the tubular are coated and radio-active. Disposal of these will bring high environmental costs which can be avoided leaving them in the well.
- Expandable cement creates excellent bonding and very low permeability at a quick setting time.
- Simultaneously tasks can be performed on the platform

<u>Challenges:</u>

- Verify a good cement plug in wellbore and behind casing according to NORSOK D-010 standard.
- Early setting of cement in coiled tubing.
- Crew need to be multi skilled with wireline, coiled tubing and cementing.
- Good well cleaning. Scale and BSS can be a big obstacle for the cement plug.

10.2 BP Miller platform abandonment:

The PP&A job in Oman used coiled tubing and had a very good outcome. In the North Sea, BP has performed a well abandonment of the Miller platform. Unlike the job in Oman the Miller platform was abandoned using wireline on many tasks. This abandonment procedure also had a goal to use the rig as little as possible and just as Statfjord, the wells on the Miller platform are in a heavily scaled environment.

The job started as usual with preparing the well for the operation. This involved drifting the well with slickline to confirm access and then setting a bridge plug in the tubing. Perforations were shot above the plug and circulate tubing and A-annulus to seawater. The setting of plug and perforations was conducted using slickline technology. The main goal with the preparations was to determine the tubing integrity and see which wells that could be abandoned using conventional circulation. If the wells had tubing to annulus communication they needed a coiled tubing unit to spot the cement at required depth. Results showed that seven wells needed coiled tubing so a coiled tubing unit took over and circulated the first cement plug. This cement plug was then tagged and pressure tested. A second run with perforation guns where runned to perforate above the cement plug before a second cement plug was circulated into place. A third cement plug was also required to isolate a second shallower, but smaller reservoir. For this plug a viscous reactive pill was set as a base before circulation of cement began. Now the reservoir section is fully isolated with two barriers, but operation is not finished yet. A fourth shallow plug was also required to isolate tertiary sands. For this operation the $10^{3/4}$" casing needed to be perforated along with the tubing in a multi perforation run before OBM in B-annulus was circulated out. Then another viscous reactive pill was circulated into tubing and A&B-annulus and perforations shot above the pill. Final displacement of cement was then conducted and cement was placed across tubing and A&B-annulus [9].

As described this well abandonment procedure did not require the need for a drilling rig to pull the tubing or casings. The operation required therefore perforation of multiple casings to put cement over a cross sectional area. The multiple perforations of tubing and casing were achieved by varying the size and configuration of perforation guns. As in the previous case in Oman, it was important for BP's Miller abandonment program to develop a multi-skilled crew to handle slickline, coiled tubing and pumping services. One other important aspect about this abandonment job was the use of the intervention mast. Since it is designed to be powered away from the well center, the mast gave the opportunity to perform a rapid changeover from coiled tubing to slickline. When slickline was used for all perforating and plug setting tasks, many changeovers was needed and a great amount of time was saved. When the mast was rigged up on drill floor the coiled tubing was disconnected and lifting operations was executed through the mast. This reduced the HSE issue since workers no longer worked beneath suspended load [9].

The Miller platform abandonment procedure is a very interesting study. The wells are abandoned according to OGUK requirements and are quite similar to NORSOK D-010.

Advantages:

- Much wireline operations
- Coiled tubing cementing
- Multi-skilled crew
- Innovative use of intervention mast
- Simultaneous cementing operations due to good planning

Challenges:

- Verify cement behind casing
- Rig floor space
- Training of crew
- Accurate well planning of abandonment procedure

10.3 Casabe Field, Colombia:

Schlumberger and Ecopetrol has from year 2009 abandoned the Casabe field in Colombia. The field consists of both producing wells and injector wells. The abandonment method on Casabe field differs from the previously mentioned cases from Oman and Miller platform. In Casabe they decided to pull the tubing with a pulling rig and then cement the well using coiled tubing. They had some problems cleaning the well before the operation itself due to sand fill in the reservoir perforations. To deal with this problem they used a coiled tubing unit to clean the sand from the inside of injection string. The key of this abandonment job is the rapid change from coiled tubing to pulling unit and then back to coiled tubing again. The abandonment solution is very simple; first they clean the sand in perforations and check the access to the well. Then the perforation was cemented 100% by the coiled tubing unit. A rapid change from coiled tubing to the pulling unit was needed to pull the tubing. The tubing was left with some joints back in the hole with the production packer. With the tubing out of the hole the coiled tubing was again rigged up and left the final cement plug in the intermediate casing, completing the abandonment operation [10].

This procedure is far from NORSOK D-010 and Statoil's requirements for a PP&A job. However, because of the problems at Statfjord with logging the cement behind casing, the tubing most likely needs to be pulled also at Statfjord. It is therefore interesting to look at the solution chosen on the Casabe field where the coiled tubing unit and rig work in each their turn. Transforming this idea to Statfjord could lead to abandoning multiple wells at the same time, saving a lot of time and money. Using the coiled tubing unit to place the cement plugs saves a lot of time during RIH and POOH. In Casabe they saved in one well 70% in time and 52% of total cost from the previously conservative planned method. This lead in total to the entire field saving 181 days of workover rig time. A total cost of $ 1,500,000 was saved from initial estimations. If this method of switching between coiled tubing and rig could be transformed to Statfjord the PP&A could be much more effective. Some advantages and challenges are:

Advantages:

- Cost effective use of time.
- Pulling of tubing and casing leads to a safe and clean operation
- Multiple wells to be abandoned simultaneously
- Able to verify cement behind casing

Challenges:

- Rapid change from coiled tubing to rig
- Training of personnel
- Deck space
- Stuck in well while cementing on coil tubing

10.4 Hydrawash:

Hydrawell has introduced an innovative method to replace the need for section milling. It is called a PWC system, perforate wash and cement, or HydraWash. It is being used to create an annulus barrier in an uncemented casing. In the traditional way, a situation like this would require removal of casing by section milling. And then clean all the debris/swarf before undereaming and setting the balanced cement plug. This is a time consuming and expensive operation. The PWC method is much more effective. In only one run it perforates the casing and washes behind it before dropping the lower plug element to work as a base for the cement plug. After the plug is in place, the cement plug is set in both annulus and tubing through the tool which now act as a cement stinger. After the tool is pulled out the tubing, cement needs to be drilled out and logging tool runned down to verify the cement bonding behind casing. If the cement job behind casing is successful a new tubing cement plug is set to create a cross sectional plug that is tagged and pressure/load tested [11].

The Hydrawash has recently been used by both ConocoPhillips and Statoil with great success. During 2009 a ConocoPhillips operation using the conventional section milling procedure took around 10.5 days. In 2011 ConocoPhillips introduced the PWC system and reduced the previously 10.5 days down to 2.6 days average for a single run. And over a twenty job history it is estimated that over 124 rig days has been saved. These saved days can be used for other intervention tasks and increase the income and make the operation even more cost effective [11].

Advantages:

- Perforate, wash and cement in 1 run
- Swarf handling, transport and disposal are eliminated
- Much more time and cost effective compared to conventional milling techniques

Challenges:

- Achieve good perforations to wash and cement
- Coiled tubing?
- Achieve good cement squeeze

10.5 Sandaband:

The traditional plugging method is to set a series of cement plugs to isolate the pressurized zones from each other. In 2002 a new company called Sandaband AS started up in Tananger in Norway. Sandaband AS has invented a competitive alternative to cement called sandaband. Sandaband is an unconsolidated well plugging material of concentrated sand made into pumpable slurry with water and brines. Sandaband is characterized as a Bingham material where 70-80% of volume is solids and 20-30% is water and other fluids. Being a Bingham material allows the material to be pumped as liquid and turn solid, but not rigid, when reaching its place in the well. Location of the plug is verified by circulating bottoms up at TOC and observing sandaband returns. One of the things making sandaband so much time efficient versus cement is that sandaband has no need for tagging cement, hence the period for waiting on cement to settle is eliminated.

Since sandaband is such a new technology it has not been widely used in the oil industry yet, but when it has been used, sandaband has proven to be a very good well barrier. In Statoil it was used for a temporary P&A on Kristin field in 2004. The sandaband slurry was pumped down to seal off the reservoir in a HPHT well while waiting on completion equipment. In 2006 it was washed out under a controlled sink rate with no problem at all. The well was a complete success and became the best producer in the Kristin field. Sandaband has also been used as a barrier in a permanent P&A at Albuskjell field operated by ConocoPhillips in 2004. In this case it was used as a barrier element in the 20" casing forming a 121m long plug with great success. Also DNO (Det Norske Oljeselskap) has used sandaband in PP&A of an exploration well. In this case it was used to plug from TD to above reservoir (300m). Overall the pumping and displacement of cement took 1.5 hrs. and the job was completed with great success.

Advantages:

- Gas tight
- No shrinkage, fracture or micro annulus
- Environmentally friendly
- Time efficient since no WOC

Challenges:

- Long term well integrity
- Sustained casing pressure
- Place right amount at the right place
- Wells eternity pressure

10.6 Shale formation as barrier:

Statoil is one of the leading innovators in the world when it comes to using shale formation as a barrier. The shale formation becomes a barrier element when it collapses around the casing after the hole has been drilled. The overburden pressure is too big and stresses in formation are not strong enough to hold the formation in place. To ensure that the well has a significant shale formation to act as barrier, an ultrasonic and CBL bond log needs to be runned. The shale is intended to solve the secondary barrier problem on mature fields. The problem consists of performing a sidetrack and not having a second 50m barrier. In these cases the conventional way is to section mill or squeeze cement through perforations. Both these methods are destructive and time consuming. Using Shale formation as barrier would save a lot of money and rig time. On Oseberg field, a first test case was performed. In this case Statoil needed a secondary reservoir annular barrier behind the $9^{5/8}$" casing. Statoil believed the Hordaland green clay could provide this barrier so tests were performed. These tests consisted of RIH with USIT-CBL logs, pressure test through perforations and monitoring annular response. All tests were successful and good shale formation bonding was confirmed.

A bonded shale formation would be a major cost saving if actually in place. Running bond logging to identify shale barrier has been carried out in the North Sea since 2007/2008. During this time over 40 P&A operations have used this method with a success rate over 90%. Unfortunately, bonded shale formation cannot be predicted and planning process ahead of a PP&A operation shall be planned using cement outside casings. Shale formation as barrier will therefore not be included in this thesis although it is important to be aware of having the possibility to use it if actually in place. It is therefore important and preferred to run logging tools after removing the tubing/casings.

11. Technology offered by service companies

11.1 Weatherford

Figure 14: *Weatherford pulling and jacking* unit [21]

Weatherford is one of the biggest service companies, especially when it comes to P&A operations. It has a wide collection of different innovative abandonment tools. One of the most interesting things they offer is the hydraulic pulling and jacking unit, figure 14. This unit comes in different sizes and has the capacity of pulling between 100 000 – 200 000 lbs. with 60ft increment and jacking 500 000 – 600 000 lbs. with 6ft increment. It is created with the intention of having a rigless abandonment procedure and provides a safe, efficient and economical solution to rigless abandonment. Weatherford has also developed a quick mini pulling unit to pull up to 30 000 lbs. that is even more cost efficient for a smaller intervention job [21]. More information on the pulling and jacking unit is found in appendix E.

Weatherford has also very interesting equipment when it comes to cutting the tubing and casing. It is called the Motorized cutting system (MCT) and is runned on electric line. It is mostly used for cutting the downhole tubulars and eliminates the need for chemicals and explosives. Its rolling cutting-wheel technology cuts a flat edge in the tubular and no debris in the well. The one thing about cutting devices is to see if they are expensive versus explosives. Since a well is being PP&A and will never be used again it is not necessary to have the cleanest cut of the tubular, but rather just getting the tubular out as quick and reliable as possible.

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11.2 Halliburton

Halliburton has mainly been used for cementing operations at Statfjord, but they do also have some tools to be used during a PP&A operation. One of them is the downhole power unit (DPU), figure 15. The DPU is a rig-safe, non-explosive electro-mechanical tool to generate a precise and controlled linear force with real-time feedback. The tool is used when setting packers, plugs and cement retainer. The tool is very flexible and can be used on electric line, slickline and coiled tubing [22]. Most operators run it on braided or slickline using batteries for power instead of electric line. By running the DPU instead of drillpipe operators have saved over $20 million in rig time. When it comes to using Halliburton as a service company during PP&A operation it seems like they cannot offer the whole package. Other companies offers cutting of tubing, setting and pulling plugs and other relevant tasks. It is therefore more likely to use Halliburton at what they do best, which is the cementing and cleaning of wells.

Figure 15: *DPU unit [22]*

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11.3 Schlumberger

Schlumberger is worldwide the largest service company. It offers multiple solutions to an easy and effective PP&A operation both with and without the use of rig. Most interesting equipment Schlumberger has when it comes to the Statfjord PP&A operations is the hydraulic power swivel stand. This swivel is a part of Schlumbergers rigless decommissioning package and is capable of pulling 100 000 lbm in a 72 inch stroke [23]. The whole package consist of a false rotary table and tong crane that hydraulically strokes and rotates away to clear the keyway. The power tongs are used with wraparound low-friction jaw technology and provide ideal gripping capabilities with reduced pipe deformation, stress and marking. If the power swivel can be used to pull tubing and casing on Statfjord this would be a highly interesting package to take a closer look upon. However, it looks like it is some of the same concept Weatherford has with their hydraulic pulling and jacking unit and that has a lot more capacity than Schlumbergers solution.

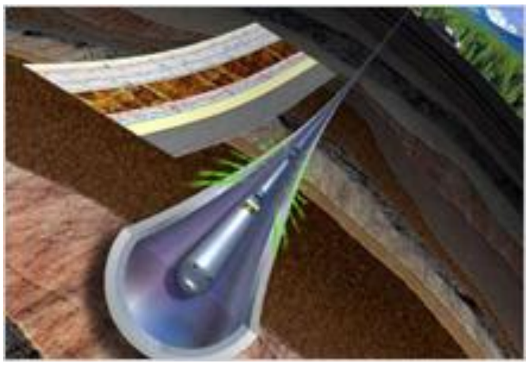

Figure 16: *Logging tool [25]*

At the bottom Schlumberger has invented an annular swivel sub for cutting wellhead and casing.

The swivel sub combines annular pressure release with casing cutting operation. In this way it prevents lost time during P&A without damaging the sealing elements. The swivel sub is an integrated part of the string, spaced out to be positioned at the level of the sealing element.

Another tool Schlumberger has in their inventory is the 2M cut-and-pull system. This is a single trip casing cutting system and eliminates the need for a marine swivel and a long drill collar string by using only one stand of 8 inch drill collar above cutting assembly [24]. The system consists of a 2M rotation spear, the hydraulic pipe cutter and a non-rotating stabilizer placed above the pipe cutter. During operation the workstring can easily be removed from the wellhead and no overpull is required. Since the weight does not have to be slacked off onto a marine swivel this tool is very good for deepwater operations. Keeping the string straighter by the centralizers reduce the risk of rotating fatigue bend failure.

Schlumberger has also invented a 2M spear that during a P&A operation can be used for retrieving tubulars and casings. The spear offers a single-trip recovery of tubulars and casing by engaging the casing prior to cutting, severs mechanically by a normal pipe cutter and recovers to surface. All in one operation which saves a lot of rig time. By using this spear the casing cutting tool is allowed to operate in a neutral position. The spear itself is engaged in the casing and bearings are capable of supporting 600 000 lbm allowing it to operate under severe rotating loads.

Figure 17: *CT SEAS [26]*

In 2003 Schlumberger introduced a new coiled tubing unit called CT SEAS, figure 17. This unit is designed to lower CAPEX and is a smaller in size and weight than previous conventional units [26]. Control and monitoring are mainly automated causing reduction in required personnel. The new unit is expected to reduce the crew size by 30%, rig-up time by 75% and rig-down time by 40% over a conventional CT unit. This unit would be very interesting if this unit could be used for multiple tasks such as cut tubing/casing, set plug and to perform cementing jobs in the wells.

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11.4 Baker Hughes

Baker Hughes is like Halliburton one of the biggest service companies in the world, but unfortunately they have not specialized themselves in P&A. However, they do have an interesting Coiled tubing system. At Statfjord, Baker Hughes currently has the coiled tubing contract. As mentioned earlier coiled tubing has not been used during a PP&A operation on Statfjord before. Coiled tubing has only being used during well stimulation or well cleanout operations before. This reflects in the way Baker Hughes presents their coiled tubing system as well. Most of the equipment is based upon well stimulation and cleanouts, but some of the equipment may be useful during a PP&A operation. The Telecoil system is one of these innovative approaches [27]. This system offers a real time downhole communication system to maximize the efficiency of any coiled tubing operation. Information such as differential pressure, temperature and depth leads to a safer and more optimized job performance. Another useful feature is the Baker Hughes EasyReach tool that creates vibrations along the entire length of the coiled tubing to enable deeper penetration. Combining this with a non-damaging lubricant ensure access to long horizontal wellbores. At last, but also important equipment is the PipeCheck system. This is a system that is runned prior to a critical coiled tubing operation. The system monitors the tubing integrity, diameter, wall thickness and localizes defects all in real time.

Baker Hughes offers also a rigless intervention system for operations such as abandonment. However the system is mostly used for subsea wells [28]. The system offers the possibility to cut the conductor in 50 ft. sections. In addition it has a 250-ton pulling capacity and fits up to 36-in. OD-pipes and has independent hydraulic power for all operations.

This Internal/external cutter tool is designed to lower cost when cutting casing/tubing, see figure 18.

Figure 18: *Internal and external cutters [29]*

The internal cutters are runned with stabilizers to ensure an effective cutting time [29]. External cutters are only runned when the ID of the tubing/casing is plugged and the fishneck is known to be free or washed over. Since the external cutters are runned on the bottom of the wash pipe the cutting operations is performed in one run. The inside cutters are lowered to TD and the tool is rotated to the right while lowered into the hole. This allows the friction block to unscrew from the mandrel and anchor itself to the wall. When the cut is completed the workstring and friction assembly returns automatically to the run-in position. The cutter tool also has the possibility to do multiple casing cutting. The tool is constructed to be runned either on pipe or wireline. This is very good since preparations on well before PP&A job requires much wireline tasks.

Baker Hughes offers also a wide specter of bridge plugs to be used during a PP&A operation. All these plugs are set by wireline, coiled tubing or pipe. The intention in this thesis is to evaluate if they can be used as foundation for the cement. If a plug is used as foundation no pressure test of the cement above is required and less cement needs to be pumped. This may be more time and cost effective and more calculations on this topic are found in chapter 16.

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11.5 Aker Well Solutions AS

Aker well solutions are the biggest supplier of wireline services on the Norwegian continental shelf. They have a wide expertise on different operational challenges. Their fleet of wireline packages consists of over 30 units with full pressure control equipment. Aker support wireline services in all categories such as slickline, braided line and electric line plus specialized services such as H2S and heavy duty units fishing. One of Akers main features is the wireline tractor service. In 2003 they introduced the PowerTrac technology, a tractor which has the best performance in the industry. The tractor helps the wireline to reach the horizontal wells and push the tool further into the well where gravity force is not sufficient enough to drive the tools further. This happens usually around 65^{o} inclination. The PowerTrac is capable of running on any standard wireline cable and is compatible with most third party tools. In 2009 Aker took a step further and also introduced a new section to the PowerTrac, figure 19. This was the introduction of the PowerTrac@Advance 434 which allowed tractor runs in an open hole environment with the ability to reverse in case the cable is stucked. Aker also simultaneous introduced a new technology called logging while tractoring that makes it possible to log the hole in real time while performing other intervention tasks [30].

Figure 19: *PowerTrac tool [30]*

In addition to wireline they also offer a coiled tubing solution to fulfill all safety and environment concern to meet the industry demands. The coiled tubing equipment encompass features such as “real time” pipe fatigue monitoring, emergency stop system, depth and weight accuracy system, coil detector on riser and more [31]. Although Aker well solutions have a solid coiled tubing system, it does not seem that they offer an innovative enough system to take over as coiled tubing contractor from Baker Hughes. They will however stand firm as the leading wireline company in the North Sea and will be used for many intervention tasks where wireline is needed.

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11.6 Archer

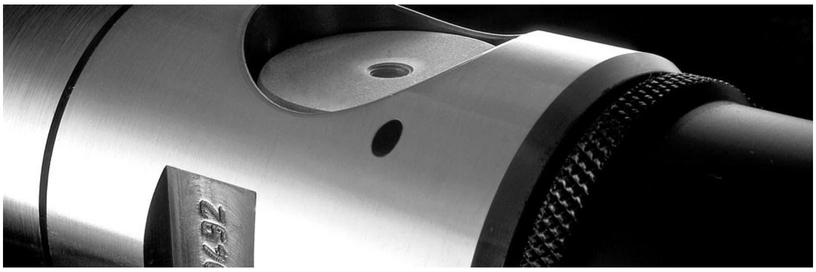

Figure 20: *Archer tool [33]*

Archer Well Company has an inventory of equipment and solutions to satisfy every operation that may come up. On wireline they can provide a full package with logging tool, plugs and packers. Their logging tool, the Space 3D imaging platform, is a very effective resource tool using the unique properties of ultrasound energy [32]. In a cased hole the conventional investigation method include mechanical calipers, downhole cameras, gauges and basic production logging. Using these tools on one of the industry's most advanced fleet of slickline and electric line provides a safe and effective intervention performance. If anything should go wrong in an operation Archer has put together a specialist intervention team to take care of specially challenging problems [33]. The team is highly experienced and multi-skilled troubleshooters. The group is particularly skilled in using $2^{7/8}$" heavy-duty fishing toolstring on a 5/16" braided wire. This specialist group is not intended to be used in a PP&A operation, but is interesting to keep in your mind as a contingency if something goes wrong.

In addition to the wireline equipment Archer can also provide a coiled tubing solution. Inside this coiled tubing package comes a flow back support and pumping system designed to increase the well performance. Unfortunately they have no new record breaking technology to make them more attractive than other coiled tubing providers.

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11.7 Interwell:

Figure 21: *HEX plug [34]*

Interwell is a smaller service company started in Norway in 1992 as BTU and has from there changed name rapidly until named Interwell in 2011 [35]. During the years it has gained more and more experience which has lead Interwell to become the main provider of plugs, packers and straddles on Statfjord. Interwell offers equipment compatible for both wireline interventions and coiled tubing interventions. Their inventory consists of bridge plugs for all types of wells such as HPHT and highly deviated wells. Interwells newest accomplishment came in 2012 when they introduced the new HET- High Expansion Temperature- Plug. For a PP&A operation it is most natural for Interwell to be the provider of plugs for PP&A preparations and cement fundament. They are well known with the history and challenges at Statfjord and will provide a safe, secure and efficient operation.

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11.8 HydraWell

Figure 22: *Hydrawash tool [36]*

HydraWell is another small company founded in Stavanger in 2008. Their personnel have extensive years of experience from multiple nations and departments. The development and innovation of the previously mentioned HydraWash system is their most interesting sales object for a PP&A operation. As mentioned the system is based upon plugging the well without the need to mill any sections. The system consists of two different tools, the jetting tool at the bottom and a cement stinger on top, see figure 22. During an operation the HydraWell system is runned with a third party TCP guns on the workstring. After perforations the jetting tool washes and cleans out debris in the annulus behind casing. A ball is then dropped down into the well to release the jetting tool from the toolstring [36].

The toolstring is now converted to a cement stinger tool and the released jetting tool will act as a base for the plugging operation. Cement is then placed on top of the base plugging the well in its entire cross section creating a successful well barrier [36].

This procedure will create a lot of benefits. First of all it will eliminate the need to milling a section, which is a very costly and time consuming method. The HydraWash system also performs all operations in one single trip down the well saving a lot of time versus conventional method. In addition to being available for all casing sizes HydraWash also allows full flow while tripping in and out of the well. The HydraWash system is intended to be used at Statfjord PP&A if the cement outside of the liner/casings is insufficient as a well barrier element. It will then be used to wash away the bad cement and replace it with new and better cement. If the cement cannot be verified by pressure or load testing the well needs to be drilled out again to verify the cement behind casing.

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11.9 CloughHelix

CloughHelix is an Australian service company with its main operation area around the Asia Pacific Sea. They are specialists in providing tools for well intervention tasks in subsea sector. In their well abandonment inventory the Cement injection tool (CIT) and the AXE multistring casing severance tool are the most interesting for a PP&A operation at Statfjord.

The CIT tool provides perforations of multiple casings before accurately placing the annular cement plug at TD in one single run. The cement injection tool and perforation subs (upper and lower) are lowered into the well to TD where lower perforation sub is activated and the annular pressure is monitored. The lower perforation sub, which is situated up to 100m below the packer, is activated and circulation down the annulus and up a flow path through the CIT is established. This will enable a 100m cement plug to be placed in the annulus. After the annulus cement plug is set, the CIT can be disconnected and a cement plug placed on top making the CIT to function as a base for the plug. This is quite similar as the HydraWash tool principle.

The AXE Cutting system uses the principle of a high pressure water jet cutting system. The Axe cutting tool is entering and cutting wellheads with 7" casing and cuts through the 7", 9 $^{5/8}$", 13$^{3/8}$", 20" and 30" in a single pass cut [37]. The cutting system is powered by 450 bhp diesel power pack and may be operated independently from rig service. It is deployed from the rig using either a simple A-frame or crane.

Figure 23: *Cut and retrieved casing strings* [37]

Both these two systems are very interesting and would probably provide a safe and effective solution.
The only downside is that CloughHelix is originally a subsea oriented service company and most equipment and personnel is trained for subsea intervention with no risers. If one of the two systems described should figure in a Statfjord PP&A operation in would be the AXE Cutting system. For this to be used an abandonment method where all casing may be retrieved at the same time needs to be configured. As of now, that looks like a highly unlikely situation as long as NOROSK and APOS regulations remain unchanged.

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12. Well status on Statfjord A

In this chapter there will be a presentation of status of different wells on Statfjord A. The chapter will explain the most economical way of decommission the field based on well status as either producers, injectors or plugged.

12.1 Plugging order

Figure 24 illustrated the individual status of each well. The colours describe in which order the wells should be PP&A. Green colour indicate that the well is not producing any longer. This is primarily old injection wells that have been plugged during the years. Then there is the yellow colored, these wells come in the second wave and also consist of injectors. The orange coloured tiles are wells producing without any gas lift at the moment and are third group to be PP&A. The red tiles are wells either producing or getting new wells drilled. The idea behind this grouping is to find the most effective way of performing a PP&A of an entire field. When finished with the green well slots, hopefully some of the yellow ones are qualified as green and wells that initially were orange are now yellow and so on. These colours are not necessarily based on a cost effective solution, but on production potential and opportunity to perform simultaneous operations. This is important to make the wells with production potential actually produce hydrocarbons to the final end of Statfjord life and rather concentrate on dead wells [13].

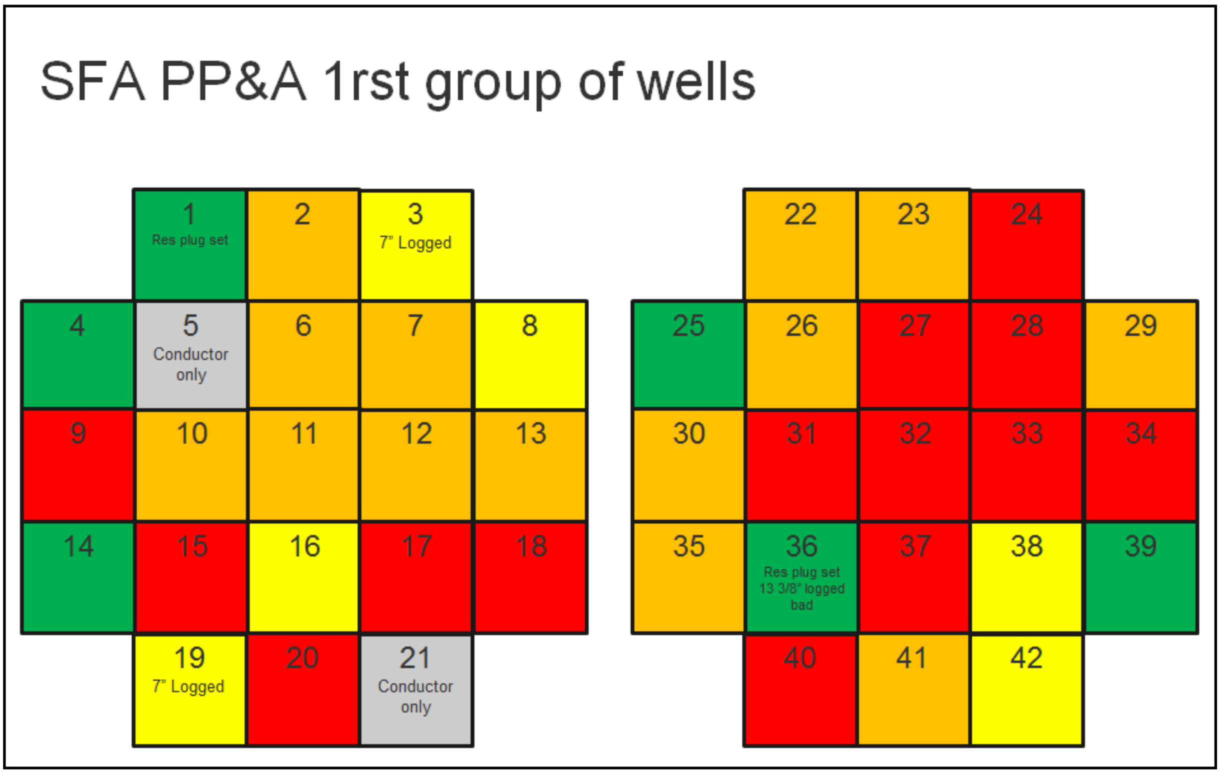

Figure 24: *PP&A grouping order [13]*

Appendix C shows a more detailed overview of the status for each individual well. The most valuable information presented is the coiled tubing potential and whether the well has verified good cement outside liner/casing. It also shows that three of the first six green wells do not have coiled tubing potential. This means that it is extra important to perform simultaneous operations, or at least have a strategic approach toward what operation is performed when and where.

Taking A-14 as a starting point it shows from figure 24 that this well is on the far left side of the first shaft. A-14 has coiled tubing potential and will require a big footprint along with the pulling and jacking unit. It will then be reasonable to look over to the opposite site and to well 29, 34 or 39. These wells all have different colours and different operations are possible. Options are therefore multiple and the drilling rig may be used for PP&A on will 39, intervention work on 29 or 34 or drilling a new well on slot 34. Doing it in this way may cause the new PP&A method with initially high cost to actually be more cost effective over the long run. Reason for this is all about time and not needing to perform too many PP&A operations when the production stops and day cost of rig grows up over double amount from today.

A lot of wells on Statfjord A have some issues with external cement. These wells may take even more time to first log the cement and then perform an operation to remove the old cement and setting a new one. Nowadays logging tools are being runned into the wells for each intervention job to create a solid picture of which wells that need new cement. Work should continue until all wells are logged to make it way easier to plan ahead and make good decision so the decommissioning takes as less time as possible.

13. Technical and well limitations

When performing well intervention tasks there are several aspects to consider that may influence the accessibility of the intervention tools when entering the well. These considerations is especially regarding the inner diameter (ID), outer diameter (OD) and scaling issues. With so many different casings, GLV, side pockets, etc. there are many possible obstacles that may cause severe problems when running tools into the well.

On Statfjord there have been several issues in the recent years considering ID and OD of tools in the well. The reason for this is that earlier the well engineers did not think of later intervention operations when completing the wells. This has led to that instead of the ID closing down when entering further into the well, the ID may suddenly be very small higher in the well and larger further down. This difference in ID makes it difficult to enter the well without planning to pull out lots of the equipment already installed. When performing interventions high in the well the intervention tool usually has a large OD and risk being stuck in the well with tools previously installed. It is then very time consuming and costly to pull out the equipment first and replace it with another tool with larger ID. Luckily has the engineers in recent years been more aware of designing the wells in the most structural way to make it easy for upcoming interventions.

Figure 25: *Scale deposits [39]*

As mentioned earlier and stated in the introduction of well A-17 B, there is a big problem regarding scale on Statfjord. Scale is a deposit formed inside the tubing and casing made of hydrocarbons and water caused by changes in pressure and temperature. It is hard to remove scale from the well and very difficult to completely remove scale. There are several different methods for removal dependent on where the scale is located. Most common place of scale deposits to form on Statfjord is in the pipe, especially around the annular safety valve. Scale deposits in pipe require a time consuming operation either in the form of milling operation or broaching. The most common method used in Statoil when the scale is located in the pipe is broaching. A Broaching tool is based upon scraping the scale off the wall by exerting a heavy force from above [38]. If exerting force is not sufficient to remove the scale a milling operation needs to be prepared. This is a proven but, expensive operation and should be a last way out. Another option is to use chemicals to dissolve the scale. In Statoil the chemicals to remove scale is usually just used when the scale is located in the reservoir. However there are many different suppliers and very much research being performed on this area so times may change. Until now, the mechanical removing of scale works fine and remove the issue with fluid control on platform that may be hazardous and toxic and possibly damaging the well.

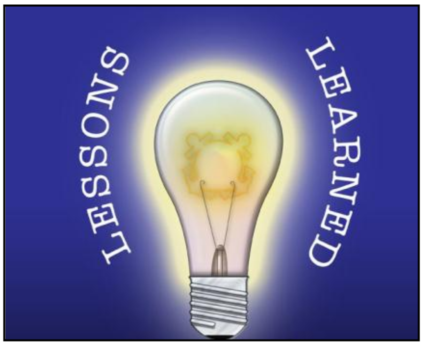

Figure 26: *Lessons learned [40]*

Even though cementing on coiled tubing is not a brand new cementing technique, it has never been used on Statfjord before. Engineers in Statoil therefore have to go through a learning process to gain as much experience as possible. It is important not to get to defensive and always pick the safest solution. Around the world there is a great amount of experience on coiled tubing cementing and the technique is well developed and incorporated in other companies. Statoil need to join in on this movement where a lot of time and cost resources can be saved. The learning process is a trial and error experience. The first wells may go a bit slow, but as the cementing technique is used more and more effective procedures and routines are gained. It is therefore recommended to always have a lesson learned after at least the first cementing jobs. Working with service company personnel with coiled tubing cementing experience will decrease the time of learning process and is highly recommended.

The main idea of performing PP&A offline is to free the drilling rig to perform simultaneous operations to increase the production on producing wells. These simultaneous operations require each their pumping units. Normally this is not a problem on large platforms, but at Statfjord A there is already very little space to install a new pumping unit and pumping lines. Further investigations on the space requirements of a pumping unit need to be performed. Having the possibility to perform simultaneous operations will not only benefit Statfjord A, but platforms such as Statfjord B and C may adopt this method when their PP&A operations starts. It is then important to have a good strategy of how to solve different issues regarding operations and logistic.

Setting a cement plug by a coiled tubing unit requires high precision and good detailed planning. The coiled tubing string usually has a dimension between 2”-3” which makes cement pumping a risky operation. Setting cement plug on coiled tubing allows a precise establishment of a barrier. However, long cement plugs require a lot of cement and require a lot of tank capacity. This leads to a larger footprint for a coiled tubing cementing operation than a regular coiled tubing operation. While injecting the cement, pumps has to run continuously during operation and while setting the cement plug the coiled tubing string needs to be pulled upwards. This cementing procedure is described more detailed in BJ services paper by Lance Portman, “Cementing through coiled tubing: Common errors and correct procedure” [14].

As always when dealing with cement there is an issue regarding the well inclination. On Statfjord A most wells have a high inclination and this will affect the possibility to run coiled tubing and the setting of the cement plug. The cement will accumulate at the wells low side and when setting the plug with coiled tubing it may be difficult to set a cross-sectional barrier plug. It is therefore very important to sustain a high pump pressure of cement to ensure it settles in the right area and not set prematurely.

14. R&D needs

This section will describe a variety of methods that was considered in the thesis to perform PP&A operation offline. Some of the ideas are researched by Statoil in these days, but are currently just ideas and a final method lies into the future. Other options presented are created from brainstorming while others are methods used earlier in Statoil. These are methods that for some reason got abandoned as a regular intervention method, but could still be a very cost effective alternative if performed under good conditions, experienced personnel and good planning.

14.1 Pull tubing/casing with platform crane

Figure 27: *Statfjord A with supply boat [41]*

One of the options to pull out the tubing and casing out of the well was by using the crane already installed on the platform. This is an interesting idea, but a lot of modifications had to be performed on the platform for this idea to come through. The idea behind the operation itself is quite simple with pulling the tubing out of the whole while a cutting giljotin cuts the pipe when it is sufficiently out. The pipe is then laid either on the pipe deck or lowered directly onto the supply boat. If the tubing and casing is cut at the normal pressure depth, introduced in the previous chapter, the BOP might also not be a problem.

The biggest problem with this method however is the issue of HSE. Lifting and lowering big pipes over pipe deck while a lot of people working are not good practice. Eventually people would have to clear pipe deck whenever the pipe was lifted. If this method could be performed safely and effective it would be a very good alternative to the drilling rig, but as of now it will require some planning before executed. Cementing would be performed by coiled tubing and plugs would have to be set on wireline. Switching between these methods could cause some problem, but with a well detailed plan it should be alright.

14.2 Wireline cut & pull

Cutting the tubing and retrieving it on wireline is one of the most cost effective alternatives to a rigless PP&A operation. The challenges as they are presented today are that the cable does not have sufficient strength to pull the entire unit. Development on a stronger cable is probably ongoing these days, but the strength will most likely not be increased as much as to being capable of pulling the entire tubing. The idea then is based upon running a multiple cutting tool and cut the tubing into smaller pieces on say 100 ft. or more and then pulls it out on wireline [44].

This method will perhaps require a modification of the wireline rig-up such as lubricator and BOP. There is a task force in Statoil currently working on this idea, but progress is taking time and the method will most likely be too late for Statfjord A decommissioning. However, looking at the long perspective there are a lot of PP&A activities coming in the next 10-20 years and if this methods become available it will save a lot of costs. If this method can also be transformed to cutting and pulling the casing is more unlikely, but it is important to say it is never impossible. Using this method eliminates the need to switch over to another unit after the preparations of the well is finished. Instead the operation can go straight to the procedure of removing tubing from well. After the tubing is removed a coiled tubing unit must set the cement plug. If not a cement plug is available the drilling rig must be mobilized. If the drilling rig is mobilized it is very important to have a scheduled plan where the wireline unit is moved over to another well and starts either preparing the well for PP&A, pulling tubing or intervention task. In this way the platform uses its resources the most effective way as possible and there is no loss in time.

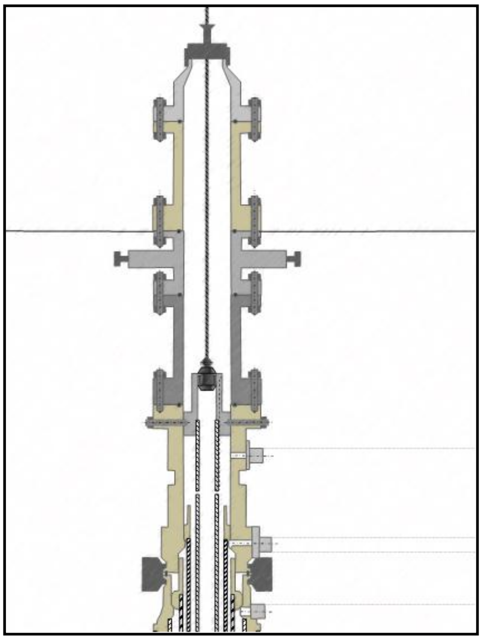

Figure 27: *Aker wireline cut'n Pull [44]*

Aker Well Solution has worked on a solution that is based upon these principles of removing small pieces of tubing on wireline. The procedure starts with cutting and retrieving the tubing hanger to surface. While the tubing hanger is pulled out of the hole the shear ram valve provides a barrier toward the reservoir. A wireline mast and pipe handling crane is used to pull the tubing and tubing hanger out of the hole. When tubing hanger is out of hole a tubing cutter is runned into well and cuts the tubing into a planned segment. Another run is the engaged to retrieve the loose tubing segment. While pulling this segment out of the hole gas was injected into the tubing to displace heavy fluid while retrieving. The gas was to be injected either by a small coiled tubing line or by a small box containing just enough nitrogen gas to displace the segment volume. To retrieve the last segment there might be some settled solid such as cement in the annulus. In that case the system can be switched off to a coiled tubing unit to pull the last section with a bit more force [44].

This method sounds reasonable to be used, but there are some major concerns. First of all the whole system seems to be on a very early planning stage and most of the equipment is not accessible as of now. The gas injection system is a bit "on the draw board" and is not concerning all safety issues that need to be validated before initializing. Perhaps in the future when equipment is further developed it will be more realistic. More information on the AWS tubing retrieval on wireline can be found in reference 44. The idea behind it is though very interesting and research should continue to persuade a solution for retrieving tubing on wireline.

14.3 Cement through X-mas tree

In 1999 attempts were made on Statfjord well C40 to bullhead cement straight through the x-mas tree to set a cement plug. Why they stopped this method is hard to say, but it certainly provided a cheap solution to setting a cement plug. There have been many discussions on why this method got abandoned, but no conclusion has been made. There are a lot of challenges with the method and to point out an exact reason why it is no longer in use is difficult. First of all the method requires verified cement bonding behind the 7" tubing. It is only in the recent years that Statoil has emphasized logging the 7" external cement to prepare for PP&A so in the turn of the century Statoil had very little knowledge of cement quality outside the 7" tubing. The second challenge with cementing through X-mas tree is how inclination in the well affects the setting of the plug. By physics laws the cement would accumulate on the low side and it would require much force to make the cement go all the way down and set a cross-sectional barrier. It seems like this method is more effective in a straight vertical well where gravity is more of a benefit than a down side. Scale is another obstacle for setting the cement and can make the cement set prematurely in the well. It is then a question if the scale can be used as a part of the cross-sectional barrier. If scale is approved and can be a part of the barrier it is better to set the cement plug by coiled tubing since this method provides a more precise placement of the plug.

The major down side of bullheading cement through the X-mas tree is the clean-up process after the cementing operation. On well C-40 in 1999 the X-mas tree and tubing was full of cement after the operation and much effort was spent just to clean up the mess with removing the hard cement from tree. This may not be such a bad thing with a PP&A situation since the X-mas trees are to be removed either way, but may still be of major concern. Easy access to the well for later PP&A operations needs to be available as soon as possible [46].

14.4 Coiled tubing; bottom cement plug

Setting the cement plug using coiled tubing may make it more difficult to ensure a correct setting of the plug than using rig. Coiled tubing has a small ID of string on around 2"-3" and need much force to push the cement. One option discussed has been to fill the hole bottom reservoir with cement to put an effective seal toward the reservoir and remove the costs of a mechanical base plug. Cement is not as expensive and is a fast and effective operation. Cement would then be filled up from bottom MD to above the external 7" cement. After the cement is set operation continues with cutting and pulling the necessary tubing out of the hole.

This method has not been used in Statoil, but is quite interesting concerning how easy and effective it is. Looking at the cost it may not save a lot of money, but will save a lot of runs up and down the well in the preparation stage of the PP&A procedure.

14.5 Blast and seal

The blast and seal method is based upon running down with explosives and perforate the reservoir until it collapses and creates a barrier toward itself. This method has been used before to a much smaller extent and taking the step to oversize it this big may be to step over the edge. A large amount of explosives will create a big risk both for offshore personnel, platform and well infrastructure. However, if it can be performed under as safe and environmental friendly surroundings as possible it is an interesting idea to proceed even further. One challenge that needs to be solved is how to ensure that there is a cross-sectional eternal seal toward the reservoir. Maybe this could be done with a pressure or load test, but there will still be a lot of uncertainty toward the barrier. As of now it is not valid as a reservoir barrier and a lot of applications will need to be sent for it to become one. It is then easier and probably safer to use already existing alternatives that is tested and used before documented success.

Figure 28: *Forward thinking [41]*

It is important to keep expanding the horizon toward researching new methods for an operator company as Statoil. Even if the idea sounds like science fiction in the present moment things may change rapidly from small improvements. Keeping the eyes open and being proactive towards the service companies may give Statoil a big advantage when researching and introducing new technologies. Statfjord has a good history of trying out new technology and the shutdown of Statfjord A platform can be a good training ground to introduce new techniques for the other oil field that soon also needs to be abandoned.

15. New PP&A approach

In section 9 a conventional PP&A procedure is described and results show that the drilling rig is used during most of the operation. In this section a new approach of performing a PP&A operation will be introduced based on the technology offered by service companies described in the previous section. This section will be more well specific to make it easier when comparing costs of conventional and proposed method.

15.1 Well A-17 - History

The new proposed method for PP&A presented in this section will be based upon the well A-17 on Statfjord A. A-17 has a long and hard history. It was finished drilled in 1990 and production started in 1991. In June 2008 sidetrack A-17 B was drilled and completed with gas-lift, a 3 ½" screen and a 7" perforated liner. Due to problems with the frac pack equipment production did not start until 07.06.09. At this time it was completed according to appendix F. When production finally started problems still kept on coming. Estimated production was initially expected to be 400 Sm3/d, but production data only showed 60 Sm3/d. Analysis performed by a build-up test on the well showed a skin factor of ~500. After another two weeks the well was decided to be shut in due to that production decreased even further and was only at 11 Sm3/d.

In August 2009 the well was re-opened and HCL acid was pumped down the well in the attempt to dissolve $CaCO_3$ particles [7]. This well stimulation operation raised the production to 23 Sm3/d, but build-up test still indicated massive skin in the well. In October the same year the well was treated with acid once again. This time with a scale dissolver and inhibitor to prevent accumulation of $BaSO_4$. The ending result was some increase due to dissolver, but after backflowing inhibitor the production decreased back to 11 Sm3/d [7].

A final attempt to fix the well was attempted in November 2010. In this attempt coiled tubing was mobilized to mill the scale, wash wellbore and place chemicals in the reservoir section. The acid was pumped in 3 stages. The first one increased the production from 42 to 250 Sm3/d, the second resulted in no increase, while the third one increased the production to 350 Sm3/d. As in 2009 when pumping scale inhibitor at the end of operation the production decreased also this time to 250 Sm3/d. Unfortunately this production did not last for a long time. During one week of production the production decreased from 250 Sm3/d to 40 Sm3/d. Statoil's theory on why the well keeps decreasing in production is that there is still some $CaCO_3$ killpill left in the well in the near wellbore area. After this the well was shut in once again, before opened for production in June 2011 for a short while before being shut in again. As of this day the well is still shut in and the plans are to PP&A the A-17 B wellbore and drill a sidetrack to the A-16 BT4 area. However in this thesis it will be planned for a PP&A of the whole A-17 well [7].

Below is a short table 5 of the parameters of wellbore and reservoir of A-17 B.

15.1.1 Well info - A-17

Year:	*2008*	**Max Inclination:**	*91°*
Length (MD):	*4490m*	**Max Azimuth:**	*38.94°*
Length (TD):	*2475m*	**Max Dogleg:**	*8.4°*
SIWHP:	*137 bar*	**Perforation interval (MD):**	*4434.5-4458.3m*
SIBHP:	*218 bar*	**Frac. Pressure:**	*325 bar*
Sand potential:	*None*	**Min. ID in well:**	*2,959" at 2390mMD*
Scale potential:	*Very High*	**Hydrate potential:**	*Low*

Table 5: *Well info A-17 [7]*

15.2 Conventional PP&A

If a PP&A operation should be performed on well A-17 today the procedure would be very similar to the procedure described earlier in chapter 9. A short description of the procedure is summarized in the following points [7][45]:

- Prepare well for handover to Well operations
  The operation starts with the well being handed over from drift to Well Operations.

- Well handover, Rig up and test wireline equipment
  Wireline equipment is rigged up on platform and tested according to safety regulations.

- Pull DHSV, bullhead and drift well
  The DHSV is POOH and the well is bullheaded to brine. When all hydrocarbons are displaced the well is drifted using wireline to ensure access to bottom of well.

- Run Caliper logging tool
  A caliper logging tool is runned by wireline to make a continuous profile of the inside

diameter variations of the tubing/casing wall. Checking for corrosion and scale.

- Run CBL and CAST-M tool
  A CBL logging tool and a CAST-M tool is runned to confirm cement bonding and to provide high resolution images of the open/cased hole for cement evaluation of the 7” TOC.

- Install HET plug
  Install a HET plug as a barrier element for further operations. The HET plug is set deep in the well at approximately 4360m MD. After wireline is POOH the plug is inflow tested and pressure tested.

- Punch and release ASV
  The ASV is released to enable the tubing to be POOH at a later stage of the operation. This operation is performed by slickline.

- Cut tubing and displace well to injection water
  The tubing is cut using explosives a few meters above production packer (2284m). This ensures that the tubing is free to be POOH. Circulation and communication between tubing and annulus is verified by pumping injection water down annulus.

- Install shallow set plug with pump open sub
  Install a plug to act as a shallow well barrier element at approximately 286 mMD. The plug is then pressure tested before pressure is bled off. Finally wireline equipment is rigged down.

All these steps above are performed by the intervention department. Wireline e-line is used during all these procedures except the one with punching the ASV. It is now time to handover the well to drilling department to complete the PP&A procedure. This means pulling the tubing/casings and setting appropriate barrier elements in the well. A conventional procedure would be performed in the following points [45]:

- Remove XMT
  The X-mas three is removed to make room for BOP and rig to enter the well.

- Rig up BOP and riser
  BOP and riser is rigged up to ensure well control and access to the well.

- Rig up casing/tubing handling equipment
  Casing and tubing equipment such as slips, Kelly, tongs and clamps are rigged up ready for proceeding with operation.

- Pull tubing

Pull tubing in two runs. Tubing has been cut at 289m as well. This section from tubing hanger to 289m is POOH before a new run is made to pull the section below from 289m-2279m.

- Set EZSV and cement liner
  An EZSV plug is set in the liner before cement is put on top of it to create a well barrier element against the reservoir. The cement plug is tagged to ensure it is in the right position.

- Set VMB plug
  A VMB plug is set in the well to create a gas-tight well barrier. VMB plugs are retrievable and require no drillpipe beneath the plug. They offer a very good alternative to cement plug during temporary P&A.

- Rig down BOP and C-section
  When rig is plugged by VMB plug the BOP can be rigged down and C-section removed. When operation is completed BOP is rigged up and VMB plug is retrieved.

- Cut and pull 9 5/8" casing
  9 5/8" casing is cut at 2100m MD and retrieved.

- Log 13 3/8" casing
  Cement behind 13 3/8" is logged by a USIT/CBL tool to ensure good bonding in the cement.

- Set cement plug in 13 3/8" casing
  If cement is proven solid outside casing a cement plug is set in the 13 3/8" casing to seal off the reservoir with a secondary barrier.

15.3 New PP&A proposal

As this new proposal is presented it shows that the first steps, the preparations, of the PP&A operation is similar to the old method. Final barrier scheme is showed in figure 29.

- Prepare well for handover to Well operations
  The operation starts with the well being handed over from drift to Well Operations.

- Well handover, Rig up and test wireline equipment
  Wireline equipment is rigged up on platform and tested according to safety regulations.

- Pull DHSV, bullhead and drift well
  The DHSV is POOH and the well is bullheaded to brine. When all hydrocarbons are

displaced the well is drifted using wireline to ensure access to bottom of well.

- Run Caliper logging tool
  A caliper logging tool is runned by wireline to make a continuous profile of the inside diameter variations of the tubing/casing wall. Check for corrosion and scale.

- Run Cement log
  A cement logging tool is runned to confirm cement bonding and to provide high resolution images of the open/cased hole for cement evaluation of the 7" TOC. From 2344mMD-3400mMD. After the logging sequence is completed the DHSV is re-installed at 276 mMD.

- Optional - Install plug in 7" liner
  Install a plug as a barrier element for further operations. The plug is set deep in the well at approximately 4360m MD. After wireline is POOH the plug is pressure tested. If there is good cement behind 7" liner this point will not be necessary to conduct and is therefore set as optional. Inflow test of plug is rarely an option on Statfjord because of low reservoir pressure.

- Punch and release ASV and displace well to injection water
  The ASV is released to enable the tubing to be POOH at a later stage of the operation. This operation is performed by slickline. Tubing is punched a few meters above production packer. Circulation and communication between tubing and annulus is verified by pumping injection water down annulus.

- Optional - Install EZSV plug in liner
  An EZSV plug is placed on top of the liner hangar in the 7" tubing to provide a base for the cement plug. If good cement behind 7" liner this point is not necessary and is set as optional. This is performed by wireline

- Cut tubing
  The tubing is cut using explosives at a depth of 1400m MD. This ensures that the tubing is free to be POOH. Normally the tubing is cut and POOH just above the production packer. Cutting it this high will lead to a lot less pipe handling on surface and time savings.

- Install shallow set plug with pump open sub – below DHSV
  Install a plug to act as a shallow well barrier element below the DHSV at approximately 286 mMD. The plug is then pressure tested before pressure is bled off. After the plug is set the wireline equipment is rigged down.

The well is now ready prepared. According to the old procedure this would be the time for the drilling rig to be engaged. However, the new proposal introduces a new solution with a pulling and jacking unit introduced in appendix E and a coiled tubing unit. Final WBS for new procedure is found in figure 29.

- Install coiled tubing Unit
  The coiled tubing unit is rigged up and safety tested according to service provider standard.

- Set cement plug in tubing
  After the pump open plug is sheared a cement plug is set by the coiled tubing unit on top of the EZSV in the tubing.

- Install and test tubing plug below DHSV
  A tubing plug is installed below the DHSV to act as a barrier during the nest steps.

- Remove XMT
  The x-mas tree is removed to make room for PP&A equipment. A junk catcher is installed during this procedure.

- Rig up pulling and jacking unit
  The pulling and jacking unit is rigged up and skidded in place to be used for pulling the tubing out of hole.

- Pull tubing
  Pump the plug open and pull tubing out of hole with the pulling and jacking unit. Pipe is handled through the V-door on jacking unit and laid on pipe deck.

- Cut 9 5/8” casing and rig down C-section
  The 9 5/8” casing is cut by pulling and jacking unit at around 1500m MD to be POOH. When the pulling and jacking unit is out of hole the C-section is removed. This will require setting an additional VMB plug to secure the well since the BOP is removed during C-section removal. The BOP is then rigged up again.

- Pull 9 5/8” casing out of hole
  The pulling and jacking unit is then used to pull the 9 5/8” casing out of the well.

- Log 13 3/8 casing and cement in 13 3/8
  A wireline is rigged up and logging tool is runned into the well to log the cement behind 13 3/8 casing. If, the cement is good a secondary barrier cement plug is set by the coiled tubing unit at around 1400m MD. An EZSV plug may be placed to act as a base here as well.

- Set surface cement, pull conductors and clean wellsite

A final surface cement plug is set in the 20" casing as the final barrier. The conductor is removed after the cement plug is set and the wellsite is cleaned according to APOS decommissioning standards.

15.4 Additional comments

In this procedure it is assumed that the well has a good cement job in the liner, 9 5/8" and 13 3/8" casing. This is an ideal case and there are many wells on Statfjord that is not in this situation. More of these well limitations and challenges are found in chapter 13.

A well barrier schematic of the proposed PP&A operation of the well is seen in figure 29 below. The first cement plug is above the hanger packer and has a mechanical plug as a base. This will provide a safe and effective seal towards the reservoir. Usually this plug would be placed above TOC of 7" tubing, but since this thesis suggest using coiled tubing to set the cement, a much more accurate placement can be achieved than by the drilling rig. Another aspect is that according to NORSOK requirements a barrier shall be placed as close to the potential influx as possible. Setting the cement above TOC would also require either section milling or squeezing cement after perforating. This would be more expensive that setting an accurate cement plug in liner. As stated this method is based on an ideal case with verified good cement bonding outside of the 7"casing, which is not always the case, especially on Statfjord.

The secondary plug is placed in the 13 3/8" casing at approximately 1400m MD. This is quite shallow depth for a secondary plug and the idea behind the placement is that the normal pressure of the well ends here. Figure in Appendix A illustrates how the pore pressure gradient varies with depth. By placing the plug where the normal pressure end will disable the need for a BOP when pulling 13 3/8", 20" and conductor. It is not yet decided if Statoil is responsible for pulling the conductor, but if they are there is an option of using NCA's (Norse cutting & Abandonment) abrasive cutting system capable of pulling all three pipes in one run. If the pulling had to happen with a BOP installed the only solution would be to use the drilling rig for the pulling job to ensure correct pressure control.

Cementing by coiled tubing is an expensive operation and not very cost effective compared to cementing through rig. The reason for why it has been chosen in the new procedure is to eliminate the drilling rig from operation and enable simultaneous operations. Hopefully will the intervention tasks performed by the drilling rig not only save a lot of time, but also increase production and indirect lower the cost of the coiled tubing cement job.

Normal procedure when P&A a well is to cut and pull the tubing above the production packer. This thesis proposes a new method of cutting the tubing and 9 5/8" at the same spot higher up in the well where normal pressure applies. This procedure will save a lot of pulling and handling of pipe to save cost and time. Since there is not much pipe retrieval less deck space is required to lay down the pipes. This will be very fortunate since the pulling and jacking unit, coiled tubing unit and drilling rig will take up a lot of the space on the platform. Making more free space will also benefit HSE issues by clearing more space for personnel to work in. Combining this with disabling the BOP, as mentioned, will save time and make planning go much easier when a lot less equipment is installed on deck.

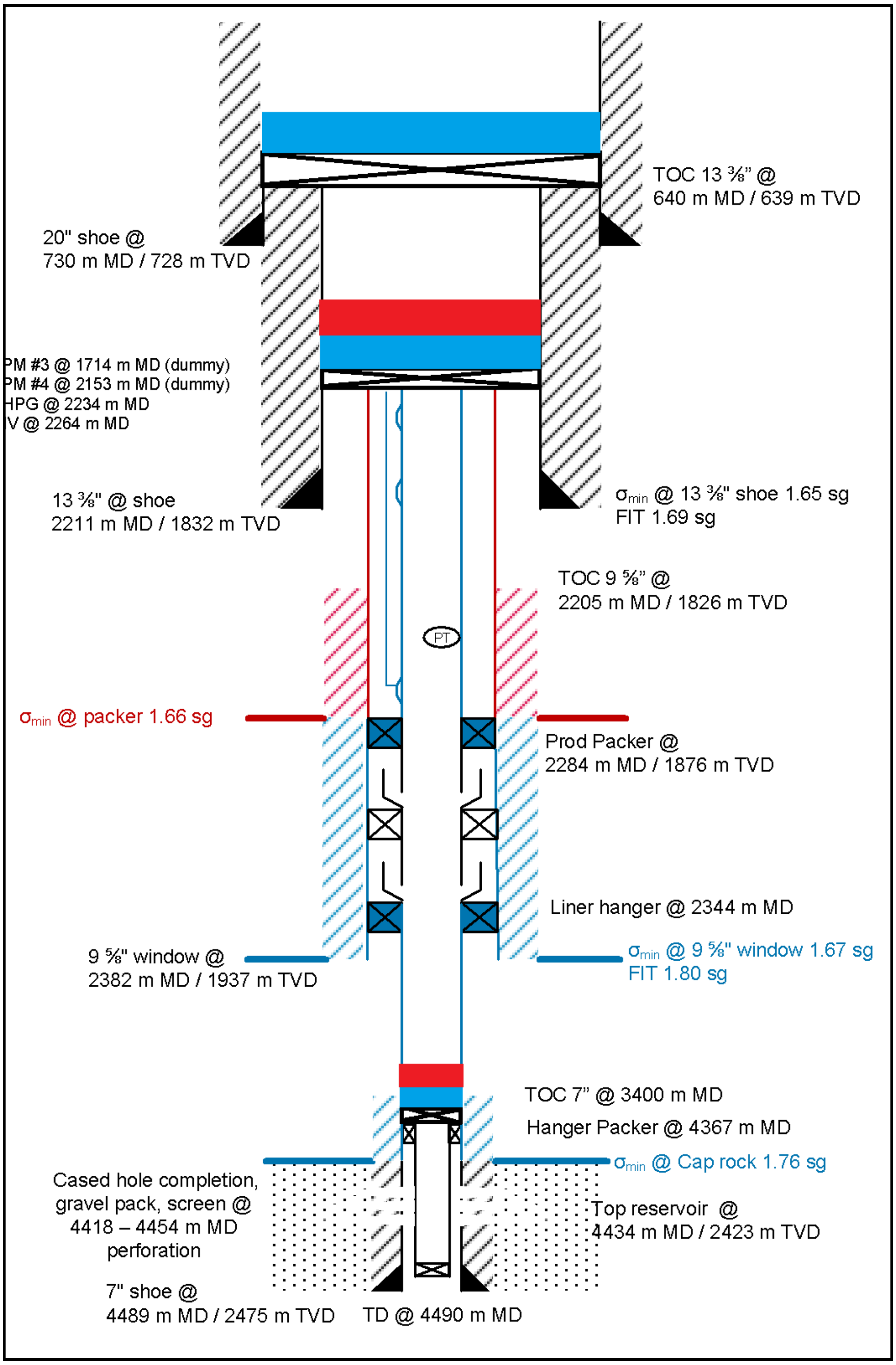

Figure 29: *Final PP&A well barrier schematic.*

16. Data Acquisition

This chapter shows the data for time and cost of the new PP&A proposed method. Numbers on costs are taken from Statoil's internal contracts with service companies. The time estimates are based upon a time calculator used by Statoil engineers to calculate time for each individual operation in a program.

Technical limit calculator				
	Activity	Hours	Fixed hours (e.g shut in)	%
	Spot	7,5		8
	Rig up	7,7		8
Run # 1:	Pull DHSV	2,6		3
Run # 2:	Run caliper	24,4		25
Run # 3:	Cement log	24,2		25
Run # 4:	Punch ASV	3,1		3
Run # 5:	Displace	2,7		3
Run # 6:	Set EZSV	8,5		9
Run # 7:	Cut tubing	5,6		6
Run # 8:	Pump open plug	5,1		5
Run # 9:	R/O		10,3	0
Run # 10:				0
Run # 11:				0
Run # 12:				0
Run # 13:				0
Run # 14:				0
Run # 15:				0
Run # 16:				0
Rig down:		5,9		6
	Total hours	97,3	10,3	100
	Total days	4,48		

Table 6: *Technical limit calculations*

16.1 Time estimations

To the left is a table of the technical limits of each individual operation. The technical limit describes the absolute optimal solution of each operational sequence. This is in cases where nothing at all goes wrong and is the best possible outcome that Statfjord is capable of. The numbers are calculated based upon length of wireline run either with or without tractor, logging interval, pumping capacity and what wireline cable is used during the operation. If there is a need to change wireline cable, slickline to e-line etc., an estimated 10.3 hrs. rig-over time has been used. Based on the technical limit it is possible to calculate P10, mean value and P90 of time estimations. As presented in the table the technical limit for preparation part of this PP&A operation is 4.48 days. This is a reasonable amount of days if all goes well, but that is certain to almost never happen.

Table 7 on page 65 shows time estimates for P10, mean value and P90 based on calculation of the technical limit. As seen the P10 is the planned time of the operation and the mean value is the budget time. P10 of the job is estimated to be 5.63 days and the mean value is 12.14 days. This shows that an operation may double in time consumption if anything does not go entirely as planned.

For the rest of the operation there are no available calculation sheets since this is normally handled by the drilling department, and not the intervention group. Numbers on these operations are therefore taken from previous well examples both from Statoil and other companies.

Operation:	Time:		P10	Mean	P90
Preparations	4.48d		5.63d	12.14d	21d
Install coiled tubing unit	10 hrs*				
Remove XMT	8 hrs				
Rig up BOP and Riser	24 hrs				
Set cement plug in tubing	35 hrs				
Rig up pulling and jacking unit	60 hrs*				
Pull tubing	20 hrs				
Cut 9 5/8" casing and r.d C-section	12 hrs				
Pull 9 5/8" casing out of hole	20 hrs		P10	Mean	P90
Log 13 3/8" casing and cmt. in	13 3/8		20 hrs		
Set surface cement and pull con.	48 hrs				
Total	257 hrs	=	10.71d	16d	28d
Total operation:		**=**	**15.19d**	**28.1d**	**49d**

* Both coiled tubing rig up and pulling and jacking unit rig-up will be performed simultaneously as other operations. Numbers are taken from the rig-up time presented by the service companies. In addition to these numbers come the spotting and testing of the units. This is estimated to take around 10 days until fully completed. Since these tests are performed simultaneously as the other operations, this value will not affect time consumption directly.

The 15.19 days approximation represents the P10 estimated planning time. This number represents an almost optimal operation. This is very unlikely since both coiled tubing and a pulling and jacking unit has never been used for cementing and pulling operations on Statfjord. Operations may then take some longer time, but as the crew is getting more training the other wells on Statfjord will go a lot easier. Perhaps down to the P10 estimate. Rig-up of coiled tubing unit and pulling and jacking unit is set to be a fixed value when service company states it takes this amount of time. In the same way as it takes 10.3 hrs to change wireline cable. WOC time is also a fixed limit and is not affected by the Mean or P90 value. All these values have been treated as a value that may vary from operation to operation, which they should not.

Well iformation

Platform	**Statfjord A**
Well	**A-17**
Type of job	**WL**
Type of rigup	**New on rig**
Season	**April - June**
Wellhead pressure:	**Under 100 bar**

Technical limit calculator

	Activity	Tech.limit	P10	Mean	P90	%
	Spot	7,5	8,7	10,4	13,1	8
	Rig up	7,7	9,0	10,8	13,6	8
Run # 1:	Pull DHSV	2,6	3,4	8,6	15,8	3
Run # 2:	Run caliper	24,4	32,0	80,5	148,3	25
Run # 3:	Cement log	24,2	31,8	79,9	147,1	25
Run # 4:	Punch ASV	3,1	4,1	10,2	18,8	3
Run # 5:	Displace	2,7	3,5	8,9	16,4	3
Run # 6:	Set EZSV	8,5	11,2	28,1	51,7	9
Run # 7:	Cut tubing	5,6	7,3	18,5	34,0	6
Run # 8:	Pump open plug	5,1	6,7	16,8	31,0	5
Run # 9:	R/O	10,3	10,3	10,3	10,3	0
Run # 10:						0
Run # 11:						0
Run # 12:						0
Run # 13:						0
Run # 14:						0
Run # 15:						0
Run # 16:						0
Rig down:		5,9	7,0	8,3	10,4	6,1
	Total hours	**107,6**	**135,0**	**291,4**	**510,6**	
	Total days	**4,48**	**5,63**	**12,14**	**21,27**	
			P10	**Mean**	**P90**	
			Planned time	Budget time		

	%
Spot	8
Rig up	8
Surface equipment	
Pumping	3
WL - DHSV	3
WL - Logging	
WL - Perf	6
WL - Plug	14
WL - GLV / Wellbore equipment	3
WL - Drift run	
WL - Sliding Sleeve	
WLT - Logging	50
WLT - Perf	
WLT - Plug	
WLT - Drift run	
WLT - Sliding Sleeve	
Rig down	6
Sum (Must be equal to 100)	**100**

Table 7: *Time estimation of PP&A preparations*

16.2 Cost estimations:

Cost estimations are estimated in the same way as time estimations. Numbers are calculated separately for preparations performed by intervention and pulling and cementing performed by the drilling department. For cost estimates of the preparations Statoil uses a cost calculator to estimate the numbers. In this cost calculator numbers on cost are taken from data sheet presented in table 8 below. The cost calculator includes personnel in its calculations and presents a total cost of the operation based on time estimations. In this way it is possible to present the numbers as P10, Mean and P90.

Cost estimates of pulling tubing/casing with the pulling and jacking unit and cementing on coiled tubing is based upon a known day rental of coiled tubing and an estimated rate for the pulling and jacking unit. It was difficult to get a rental day rate from Weatherford on the pulling and jacking unit since the unit comes in different sizes with various equipment. To achieve an accurate prize estimate it required a lot of meetings and information going back and forward. Rental cost for the pulling and jacking unit has therefore been set at an estimated value of what is thought to be reasonable. This value is set to be 1.2 million NOK per day.

Cost of various operations [mill] (NOK):

Operation:	Cost (NOK)	P10	Mean	P90
Preparations		7.76	11.82	17.5
Coiled tubing rig-up	10 million			
Coiled tubing unit	1 mill/d	15.2	28.1	49
Cement plug w/equipment	100 000			
Pulling and jacking unit	1.2 mill/d	22.8	33.8	58.8
Engineer Weatherford*	15 000*6/d	1.3	2.5	4.4
Total		**47.16**	**76.32**	**129.7**

*Handling of the pulling and jacking unit requires 6 personnel from Weatherford.

All these values are fixed; hence the P10, Mean or P90 value estimated is only based on time limits. The cost estimations of the coiled tubing rig-up estimated to 10 million NOK include spotting, testing and rig-up of the coiled tubing unit. All together this is estimated to take approximately 10 days. This will then be a fixed value and not affected by the time estimations.

Calculations performed on wireline like logging, pulling and setting plug and punching tubing is calculated by the spreadsheet and presented as followed:

Well iformation

Platform	Statfjord A	New DHSV?	No
Well	A-17	# Tractor runs	3
Type of job	WL		
Type of rigup	New on rig	WL P&A, post completion or throug rig operation?	Yes
Season	April - June		
Wellhead pressure:	Under 100 bar		

Contractor/Services	Personnel	Purchase	Rental (day rate)	Personnel (day rate)	Sum P10	Mean	Sum P90	
New DHSV		0			0	0	0	
DeepWell	6	328 771	791	73 834	748 546	1 234 952	1 916 376	
Halliburton	2	16 738		22 900	145 553	294 815	503 922	
Aker Well Service	4	547 056	0	52 576	842 803	1 185 493	1 665 581	
Schlumberger	4	23 945		50 148	306 034	632 899	1 090 816	
MI Swaco	0	0		0	0	0	0	
Interne kostnader				90 000	506 262	1 092 882	1 914 700	
Rig cost (logistic from rig if WL P&A, Post compl...)			300 000		1 687 539	3 642 939	6 382 333	
Pull DHSV					0	0	0	
Caliper		200 000			200 000	200 000	200 000	
Cement log		1 100 000			1 100 000	1 100 000	1 100 000	
Het plug		600 000			600 000	600 000	600 000	
ME pump open plug		600 000		32 000	780 004	988 580	1 280 782	
Tubing cutter		150 000			150 000	150 000	150 000	
Cement log		700 000			700 000	700 000	700 000	
					0	0	0	
					0	0	0	
					0	0	0	
					0	0	0	
					0	0	0	
					0	0	0	
					0	0	0	
Total:		4 266 510	300 791	321 458	7 766 742	11 822 560	17 504 511	Total NOK
					5,63	12,14	21,27	Total days
					P10	Mean	P90	
					(Planned)	(Budget)		

Table 8: *Cost estimation overview*

If comparing numbers from Table 8 and Appendix D it shows that it is planned to use Schlumberger caliper tool, cement log by Halliburton on the 7" liner, ME pump open plug with all equipment from Interwell, Tubing cutter from Schlumberger and a cement log from Schlumberger on the 13 3/8 casing. Regarding the HET plug installed in the 7" liner it is not the one represented by Interwell in appendix D. The plug represented by Interwell in appendix D represents the highest cost possible and cheaper plugs can be achieved by either Interwell or other companies. The value has therefore been set to a reasonable value based on highest and lowest cost.

As seen in the previous page the total cost of the whole operation is 47 million NOK as P10 value and 76 million NOK as a budget value. These values are probably higher than a conventional method mainly because the new method uses two units to eliminate the need for drilling rig.

Appendix D shows the individual cost of each equipment provided by service companies that is often used during intervention tasks. Based on these numbers calculations have been performed to estimate how much a PP&A operation would cost.

17. Discussion

The new method suggest combining a pulling and jacking unit with a coiled tubing unit to perform cementing operations to provide a complete package to a PP&A operation. Using two units instead of one drilling rig will be a more expensive operation, but will provide a much faster and effective operation. An estimated time limit on a PP&A operation is set to be around 40 days with the conventional method and this limit will require operation start already in the third quarter of 2012. Time estimations performed on the new method show a budget time limit on 28 days. This means that if operation starts in the last quarter of 2012 all wells will be finished PP&A at the end of year 2015. This will create a huge cost saving for Statoil and production could continue for another year if the goal is the end of year 2016. This number of 28 days also includes pulling of the conductor so the real number may turn out to be even lower. Keeping in mind that this is a new method and will probably have some early deceases before the crew is totally comfortable the average estimate is set to be approximately 30 days. Operating with 30 days as a starting point will hopefully be within such a wide safety margin that planning and execution will go without any major problems.

Regarding the cost estimations the new proposed offline method has a day-rate of approximately 2.5 million NOK included all equipment and personnel. This is an estimate not based on experience like the conventional number of 1.1 million NOK per day, but on a detailed calculation of each operation. If the conventional method was to be calculated the same way, the 1.1 million NOK per day would a much higher value than showed by experience. Since the historical data shows that the detailed calculations are not accurate it is reasonable to think that the calculated value of the new method actually will be lower than 2.5 million NOK. However this is a prediction that only time will tell and for now the budget value should be set at 2.5 million NOK to operate on the safe side. This will give a good safety margin toward what hopefully will be a lower real value. If the numbers turns out to be different the new numbers should replace the calculated value, either it is in positive or negative direction.

On Statfjord A there are a total of 40 wells and 12 of these wells are either not producing or operated any more. These 12 wells mainly represent old injector wells and should be the first wells to be PP&A. Some wells are capable of producing until 2016 and some wells will need intervention jobs to keep producing a while longer than estimated today. Creating batches of wells based on timing order to be PP&A is very important both for the production, income and possibility to perform simultaneously operations. Creating a schedule with a well planned plugging order will create a foreseen prediction and make planning and program writing a lot easier both for engineers onshore and workers offshore.

This thesis assumes an ideal situation which means that results from logging run during the procedure is positive and good cement is verified behind casing. In reality many wells on Statfjord have a bad cement job and contingency plans are necessary. The contingency plan when having bad cement should be running a HydraWash system to remove the old and set new cement. Statoil has recently had some problems with running HydraWash on Statfjord the first time, but other Statoil field has positive experience and HydraWash deserves another chance. This system provides a faster, more effective and cheaper solution to the old section milling system. One of the main reasons for running logging tool prior to operation start is to check the possibilities of using formation as barrier. Statoil is a leading pioneer in the work of using formation as barrier and it provides a very economical solution to external cement. If the formation is proven to be accepted as barrier all studies show that this solution is far more cost effective then cement and should be used for everything it is worth.

In the procedure it is planned to cut the tubing and 9 5/8” casing above the point of where the normal pore pressure end at around 1400m. The cement plug placed here will be the secondary barrier against the reservoir and a primary barrier against Lista formation. Lista formation is located at a depth of 1830m TVD and has a small inflow potential of 0.44 mD. This requires a plug placement above 1830m TVD and preferred in this case above 1400m MD. The surface plug placed beneath the conductor is the secondary barrier against Lista fm.

Regarding who is responsible of pulling the conductor, there has been no decisions made and discussion is still going on between Statoil and Aker well solution. How much extra pulling the conductors is hard to say at this moment and under what circumstances they need to be pulled. Hopefully they can be cut at shallow depth and retrieved in a simple operation by most likely the drilling rig.

When work started on this thesis Statoil operated under the APOS-system. This is a stricter version of the NORSOK D-010 and is created to ensure safety of every well operation. In late May 2012 Statoil introduced a new version of APOS called ARIS. The requirements are basically the same as APOS and the main difference is how easy it is to navigate from folder to folder. NORSOK D-010 is also under revision and debate is on to make the new versions requirements as much similar to ARIS as possible. ARIS is as APOS stricter then NORSOK D-010 and Statoil is the main pusher for making the new version on NORSOK D-010 as close to ARIS as possible. Other companies that do not have internal requirements, but only work out of NORSOK D-010 has a great advantage over Statoil when they do not have to work under as strict working guidelines. The perfect situation is to find the golden line between safety and cost savings, however since each field live their own life and are different such a way is practically impossible. It is therefore important to be on the absolute safe side and follow the strictest guidelines. Remembering environmental disasters happening around the world could also happen on the Norwegian continental shelf and have huge impact on the oil future of Norway. Based on this the new edition of NORSOK D-010 should be as much similar to ARIS as possible and other oil companies should follow Statoil’s example.

Intervention operations on Statfjord wells are a challenging task. The early drilled wells have a completion solution not intended to do intervention operations on. Tools with different diameter are installed in the well making it very difficult somewhere to get down with the best tools and improvisations needs to be made. The old wells also consist of old casings that have been eroded during the years creating huge holes that may affect the barrier safety if growing bigger. During the recent years drilling and completion personnel has become more aware of making the wells as simple as possible for intervention tasks and work is now going a lot easier. It shows how important it is to have a long perspective on things and think of the people coming in the future to make the way forward as easy as possible.

18. Conclusion

During this section a comparison of personnel, time and cost between the conventional method and the new proposed method is made to finally conclude of the best procedure.

18.1 Personnel

When calculating on normal operations Statoil operate with a number of 35 people as a rig crew. This number represents the people working on a daily basis on the drilling rig and performing conventional intervention/drilling tasks.

During the new proposed PP&A method it is suggested to use both a coiled tubing unit and a pulling and jacking unit. The coiled tubing unit is estimated to require 8-9 people to be operated while the pulling and jacking unit require 5-6 people. In addition comes 16 people to perform other service tasks like logging and setting plug as seen in table 8. However these people will not be there the entire operation and it is a reasonable approach to say that they represent 4 people a day when summing up. This makes the whole PP&A method consist of 18 people.

The new method takes about half the crew of a normal rig operation. From the appendix D it shows that a worker cost around 15 000 NOK per day. Taking this into consideration it shows that the new method will save around 250 000 NOK per day. During a 45 days operation this will be equal to 11,2 Million NOK which is a huge amount of money to be used on other operations.

18.2 Time

Time is the main reason to create a new method of performing PP&A. It is very important to finish PP&A the field before production stops and huge costs may be saved on the process. According to Statoil document two wells have already been approved to be PP&A. This is well A-1 and A-36. A-1 has an estimated working budget on 41 days while A-36 is budgeted to go 53 days. It will then be a reasonable approach to say that a conventional PP&A operation will take approximately 45-50 days as budgeted time.

As described previously in chapter 16 the new PP&A proposal is estimated to have a budget time limit of 28 days. Making a rough estimate this time limit is probably going to vary a bit from well to well and could be estimated as an average to be 30 days. This estimate gives some safety margin toward the estimated time on A-17.

Summing up on all 40 wells the conventional method will have a budget on 45 * 40 = 1800 days while the new method will have 30 * 40 = 1200 days. This is a difference of over one and a half year (600days) and would create a massive cost saving for Statoil as a company. It is important to keep in mind that these numbers also include pulling the conductor. It is not yet decided if it actually is Statoil who is responsible of pulling the conductor and operating days may decrease even further if an external company is responsible for the conductor.

18.3 Cost:

The conventional method of calculating cost of a PP&A operation is based on previous experience. History shows that a detailed cost estimate is not as necessary and may limit the operation to complete its mission. Engineers and economics have found that an estimated average day-rate for an operation is accepted and usually the best estimate. Major decisions are based upon this simple, but accurate method and it almost never fails. Based on this Statoil has created an estimate of 1.1 million NOK per day as a rate for a PP&A operation, making a 45 days operation cost 49,5 million NOK overall. This value of 1.1 includes everything from equipment to personnel and should provide trustful information.

The new method of PP&A has never been done before and calculating cost based on previous experience is therefore not possible. Cost estimations are therefore calculated in detail based on estimates and some known set prices. At last the end result shows an estimated operation cost of 76 million NOK which leads to a day-rate of approximately 2.5 million NOK.

Based on information that operation by rig vs. coiled tubing should cost about the same it is a bit strange how the conventional way only has a day-rate of 1.1 million NOK. Coiled tubing is estimated to cost 1 million NOK per day and is slightly cheaper than a rig. Taking also personnel and equipment into consideration it seems very unlikely that the price is 1.1 million NOK per day. This shows again that it is perhaps better to do estimations based on experiences rather than detailed studies. One additional thing this show is that the calculations of 2.5 million NOK per day for the new proposed method is probably much higher than it actually will be in reality. Most likely it will be between 1.8 and 2 million NOK per day, but this is a number that eventually has to be proven through experience.

Below in Table 9 is a short summary of the conclusion. It shows that the new method requires a lot less personnel and takes less time. Even though cost is significantly higher simultaneous operations by the drilling rig may contribute to that the total cost decreases and production/income increases. All numbers calculated for the new method is uncertain since it has not been performed before, but hopefully the numbers are not far from the truth. Based on this information this thesis concludes that a trial of the new method should be attempted when a more experienced planning team has set up a complete schedule and training is completed.

	Conventional method	**New method**
Personnel	*35 people*	*18 people*
Time	*45-50 days*	*28-30 days*
Cost	*1.1 million NOK/d*	*2.5 million NOK/d*

Table 9: *Conventional vs. new method*

19. Recommendation

19.1 Relevance

PP&A is getting more and more important. There are now over 30 years since the oil adventure started and many of the original fields are getting near the ending. Finding a solution on the best procedure to perform a PP&A operation will benefit operations for many years to come. Service companies are starting to see the potential of a rigless PP&A operation and the future is theirs to be taken. Constant development will eventually pay off and the final solution will be cost, time and HSE effective in the end. How many years it takes for this method to become accepted are only for the future to know, but for now the part time solutions needs to be tried out.

It is not only in Statfjord the rigless PP&A performance are a subject. All over the world companies are decommissioning their fields. And experience is growing for each day that passes. Gaining knowledge and arranging lessons learned meeting keeps spreading the message of what to do and how to do it. Information should not be delivered internal in Statfjord, but passed on to all Statoil departments if a job turns out to be a major success. This will help getting better results for the entire Statoil field of interest and help Statoil maintain their position as one of the safest and well known company in Norway and worldwide.

19.2 Future work

As new technology keeps improving and PP&A is getting more and more attention by the service companies new solutions will keep on coming and Statoil needs to hold their eyes open to new methods. There is a huge focus on finding a good and secure method to perform an offline PP&A operation and multiple service companies will have almost similar offers. Studying these methods and setting them up against each other to find which method is most satisfying could be a good master thesis for future students. At the time this thesis is written many of the methods are still on the "idea phase" of the process and a complete solution is still to come. It has been difficult to find a unique and good solution and luckily Weatherford was the only company with a operational history on a pulling and jacking unit.

The ultimate breakthrough for a PP&A operation would be to find a solution of pulling the tubing on wireline. Work on this area is ongoing in Statoil and most likely other companies too these days, but no solution has left the drawing table just yet. The idea behind pulling tubing on wireline is to cut the tubing into small pieces and pull them out one by one. Studies around this subject should be explored more and issues on pipe handling and barrier status when retrieving the tubing is some of the most important obstacles. Studying these issues or perhaps find a better more effective method would be an interesting task for either a summer student or master thesis.

As mentioned earlier, logging tools are deployed in every intervention operation at Statfjord these days. This is performed to log the cement bonding behind the casing of old wells. When the old wells were originally drilled no logging run was performed simply to save money. This bad procedure is now catching up so all wells needs to be logged again and lots of time and money that originally should be saved are now spent. Statoil are aware of the problem and has learned their lesson not to postpone any jobs and cement logging are now runned after each cementing job. It is recommended that this procedure continue to create an easier working environment for the coming engineers and reduce the PP&A operation time in the future.

When designing wells it is important to have a good communication between all departments. In the beginning there was little communication that lead to the drilling and completion engineers did not design the wells for interventions. This lead to too many of the wells being very difficult to do intervention on because of i.e. large variations in inner diameter created big problems and obstacle for tools. Communication between departments is therefore crucial and is getting more and more notice as time go. Planning ahead and cooperate between departments has created some of the best wells for Statoil. This communication needs to continue and wells are now designed as easy as possible for coming operations.

When doing research ahead of this thesis it was cleared that a lot of the earlier PP&A papers talked about what to do when hitting problems. Should the well be left and move over to another rig or should the tool stay on the rig until the problem was solved? Both cases has their success story and pros and cons. However when having so much rigging time of units and testing of equipment before operations, the best procedure would be to stay on the well until it is fully completed. Not having to remove equipment and starting lifting operations will be beneficial both for cost, time and HSE.

20. Nomenclature

APOS	-	Arbeidsprosesstyringssystem (Work process guidance system)
ASV	-	Annular safety valve
BaSO4	-	Barium Sulphate
BHA	-	Bottom hole assembly
BOP	-	Blow out preventer
BP	-	British Petroleum
BTU	-	BrønnTeknologiUtvikling
CaCO3	-	Calcium Carbonate
CAST-M	-	Circumferential acoustic scanning tool – Monoconductor
CAPEX	-	Capital expenditures
CBL	-	Cement bond log
CIT	-	Cement injection tool
CT	-	Coiled tubing
DHSV	-	Downhole safety valve
DNO	-	Det Norske oljeselskp
DPU	-	Downhole power unit
EZSV	-	Easy Drill Subsurface valve
FCP	-	Minimum formation stress
GLV	-	Gas lift valve
HCL	-	Hydrochloric Acid
HET	-	High Expansion Temperature
HEX	-	High Expansion
HPHT	-	High pressure High temperature
IGIP	-	Initial gas in place
ID	-	Inner diameter
IOIP	-	Initial oil in place
MCT	-	Motorized cutting system

MD	-	Measured depth
NCA	-	Norse cutting & abandonment
NOK	-	Norwegian krone
NORSOK	-	Norsk Sokkel (Norwegian territory)
OBM	-	Oil based mud
OD	-	Outer diameter
P&A	-	plug and abandonment
PDO	-	Petroleum Department of Oman
PJU	-	Pulling and jacking unit
POOH	-	Pull out of hole
PP&A	-	Permanent plug and abandonment
RIH	-	Run in hole
SIBHP	-	Shut in bottom hole pressure
SIWHP	-	Shut in wellhead pressure
TCP	-	Tubing conveyed perforation
TD	-	Target depth
TOC	-	Top of cement
TVD	-	True vertical depth
USIT-CBL	-	Ultrasonic imaging tool-cement bond logging
VMB	-	Velocity model building
WBS	-	Well barrier schematic
WL	-	Wireline
WOC	-	Waiting on cement
XMT	-	X-mas tree

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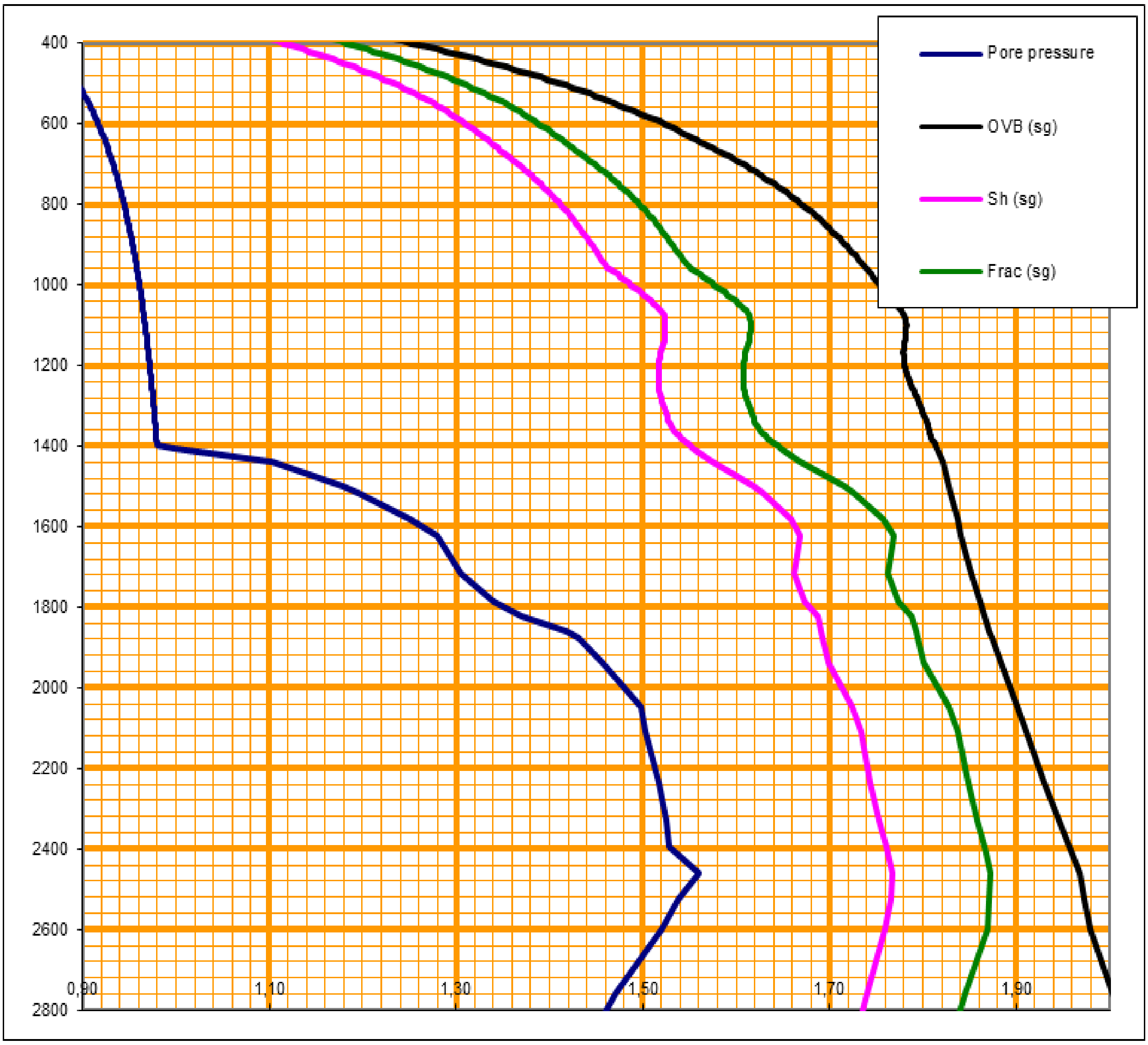
Appendix

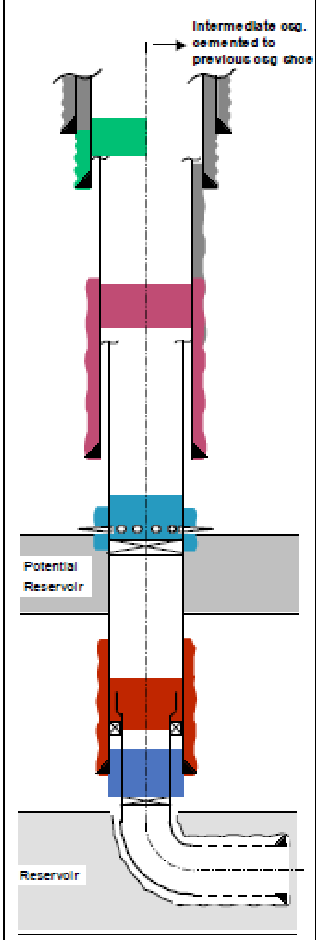
Appendix A: Pore pressure variation A-17 B



Appendix B: PP&A barrier schematic

NORSOK standard D-010 Rev. 3, August 2004

9.8.6 Permanent abandonment - Slotted liners in multiple reservoirs



Well barrier elements	See Table	Comments
Primary well barrier, deep reservoir		
1. Cement plug	24	Through liner and across casing shoe/Open hole transition.
Secondary well barrier		
1. Casing cement	22	
2. Cement plug	24	Across liner top.
Primary well barrier, shallow reservoir		
1. Cement plug	22	Squeezed into perforated casing annulus above potential reservoir.
Secondary well barrier, shallow reservoir		
1. Casing cement	22	
2. Cement plug	24	
Open holes to surface well barrier		
3) Cement plug	24	Cased hole.
4) Casing cement	22	Surface casing.

Notes
1. Secondary well barrier shall not be set higher than the formation integrity at this depth, considering that the design criteria may be initial reservoir pressure, which may develop over time.
2. The case on the right hand side indicates that the intermediate casing string is cemented into surface casing, i.e. with no open annulus to surface. Hence, no open holes to surface well barrier is required.

NORSOK standard Page 73 of 158

Appendix C: Well Status Statfjord A

		Reservoir Plug							Lista Formation Plug						
Well	Type	Plug location	Cemented ok?	CMT logged?	CMT comment	CT Possible	Comment	External job needed?	3 rd Plug location	4th plug location	Cemented ok?	CMT logged?	CMT comment	Comment	External job needed?
A-36 A	Injector	7 liner	job with losses	yes	Reservoir plug set	no	Done	No	13 3/8 casing		n/a	yes	TOC 736 m. but not good below 753 m	Top of cut @ 1232 m. Challenge to Cut & Pull 9 5/8" until 1734 m. or deeper. Then re-log 13 3/8" cement again.	Pending log
A-1	Injector	9 5/8 casing	good job no losses	yes	TOC 2600 m from log	no	Done	No	13 3/8 casing		n/a	no	TOC 378 m from FWR	Cut & Pull 9 5/8" to 1818 m.or deeper. Then log 13 3/8" for annulus cement	Pending log
A-14 A	Injector	7 liner	good job no losses	no	circulate some cement out above liner	yes	Log cmt in 7" liner because 1st and 2nd barrier will be in the same section	Pending log	12 1/4 annulus	12 1/4 annulus	good job no losses	no	TOC 9 5/8" casing 2020 m	Top of liste ~2021 mMD (1800 mTVD) so there is not enough for 200 m cmt. Log 9 5/8" cmt before defining plug interval	Yes
A-4	Injector	7 liner	good job no losses	no	TOC 3960 m from 10 1/2" OH estimation	yes	Log cmt in 7" liner because 1st and 2nd barrier will be in the same section	Pending log	9 5/8 casing	13 3/8 casing	good job no losses	no	9 5/8" TOC (CBL) at 2330 m. 13 3/8" TOC 550 m (DBR) need to be logged.	Top of liste ~2456 mMD (1800 mTVD) so there is 126 m cement which is not enough for	Pending log
A-39	Injector	7 liner	good job no losses	no	Hele liner sementert. Hullstørrelse 8 1/2"	no	Log cmt in 7" liner because 1st and 2nd barrier will be in the same section	Pending log	9 5/8 casing		job with losses	yes	Total loss 1850 bbl. During running and cementing but temp logged TOC @ 2250 m. good cement 2350 m	Top of liste ~2740 mMD (1800 mTVD) so there is enough interval for cement plug	no
A-25 AT3	Injector	7 liner	good job no losses	no	circulate some cement out above liner	yes	Log cmt in 7" liner because 1st and 2nd barrier will be in the same section	Pending log	12 1/4 annulus	12 1/4 annulus	job with losses	no	TOC 2479 m loss during displacement 53,4 m3	Top of liste ~2090 mMD (1800 mTVD) so there is not enough for 200 m cmt. Log 9 5/8" cmt before defining plug interval	Yes
A-8 C	Injector	5 1/2 liner	good job no losses	no		yes	Log cmt in 5,5" liner because 1st and 2nd barrier will be in the same section	Pending log	9 5/8 casing	13 3/8 casing	n/a	no	9 5/8" casing CBL TOC 2650 m but TOC from temp log at 2150 m. No 13 3/8" cement log	Top of liste ~2814 mMD (1800 mTVD) so there is 164 m cement which is not enough for	Pending log
A-38 B	Injector	5 1/2 liner	good job no losses	no	circulate some cement out above liner	yes	Log cmt in 5,5" liner because 1st and 2nd barrier will be in the same section	Pending log	13 3/8 casing		n/a	yes	TOC 13 3/8 600 m.Temp log	Log 13 3/8" casing	Pending log
A-19	Injector	7 liner	good job no losses	yes	CBL from 18 Nov 1981	yes	Log cmt in 7" liner because 1st and 2nd barrier will be in the same section	No	9 5/8 casing	13 3/8 casing	job with losses	no	loss 671 bbl. 9 5/8 TOC 1888 m CBL. No 13 3/8" cement log. Recheck 9 5/8" casing CBL maybe top of good cement at 1950 m	Top of liste ~2027 mMD (1800 mTVD) so there is 139 m. cement which is not enough for 200 m cmt. Log 9 5/8" casing	Pending log
A-3 A	Injector	9 5/8 casing	good job no losses	yes	TOC 2630 m not match with old excel file (3175 m) PBR at 3338 m.	no	May be need to confirm log again and mill PBR to get enough cement interval	No	13 3/8 casing		n/a	no	13 3/8 TOC 2217 m. Top of Liste ~2296m. (1800 m TVD)	log 13 3/8" casing cement before defining plug interval	Pending log
A-42 A	Injector	7 liner	good job no losses	no	liner was roated throughout the job	yes	Log cmt in 7" liner because 1st and 2nd barrier will be in the same section	Pending log	12 1/4 annulus	12 1/4 annulus	job with losses	no	9 5/8 TOC 1870 m, mud loss 47 m3 Pressure in B-annulus	Top of liste ~1924 mMD (1800 mTVD). Log 9 5/8" cmt before defining plug interval	Yes
A-16 BT4	SFLL WI Issues	7 liner	job with losses	no	loss 16 m3 while spacer out	yes	Log cmt in 7" liner because 1st and 2nd barrier will be in the same section	Pending log	12 1/4 annulus	12 1/4 annulus	good job no losses	no	9 5/8 TOC 2200 m, Foam cement downhole density 1,6 sg	Top of liste ~2117 mMD (1800 mTVD). Log 9 5/8" cmt before defining plug interval	Yes

		Reservoir Plug						External job needed?	Lista Formation Plug						External job needed?
Well	Type	Plug location	Cemented ok?	CMT logged?	CMT comment	CT Possible	Comment		3 rd Plug location	4th plug location	Cemented ok?	CMT logged?	CMT comment	Comment	
A-9	Injector	9 5/8 casing	job with losses	yes	loss 22,2 m3 while displacing. TOC 1675 m from log.	no		No	9 5/8 casing		job with losses	yes	9 5/8 CBL TOC = 1675 m	Top Liste at 2088 mMD (1800 mTVD) there is enough interval for 200 m cmt.	no
A-12 A	Producer w/GL	7 liner	good job no losses	no	Cement job was performed with full returns and liner rotation	yes	Log cmt in 7" liner because 1st and 2nd barrier will be in the same section	Pending log	12 1/4 annulus	12 1/4 annulus	good job no losses	no	Theoritical TOC 2300 m	Top of Liste at ~2013 mMD (1800 mMD)	Yes
A-10 A1	Producer w/GL	7 liner	good job no losses	no	TOC at 2469 m from 9 1/2" OH estimation. Plug did not bump with 95% efficiency+0,5 shoe track volume. Circulate out 12m3 of cement above top of liner. Overdisplace?	yes	Log cmt in 7" liner because 1st and 2nd barrier will be in the same section	Pending log	12 1/4 annulus	12 1/4 annulus	good job no losses	no	TOC 2207 m from 14" OH estimation. Theoretical TOC at 2120 m from DBR cement.	Top of Liste at ~1877 mMD (1800 mMD)	Yes
A-13 B	Producer w/GL	7 liner	good job no losses	no	liner was rotated throughout the job but getting negative pressure test of liner packer	yes	Log cmt in 7" liner because 1st and 2nd barrier will be in the same section	Pending log	9 5/8 casing		n/a	yes	TOC from CBL at 2250 m	Top of liste ~2543 mMD (1800 mTVD) so there is enough interval for cement	no
A-26 B	Producer w/GL	5 1/2 liner	good job no losses	no	liner was rotated throughout the job. However plug not bump with 96,2% efficiency.	yes	Log cmt in 5,5" liner because 1st and 2nd barrier will be in the same section	Pending log	12 1/4 annulus	12 1/4 annulus	job with losses	no	Estimate TOC in gauge hole 2217 m (TOC from FWR 2154 mMD). Total loss with pressure build up while cement out of 9 5/8" casing shoe	Top of liste ~1990 mMD (1800 mTVD)	Yes
A-11AY1, AY2	Producer w/GL	9 5/8 casing	good job no losses	yes	SBT TOC at 1808 mMD	no		No	13 3/8 casing		good job no losses	no	TOC from FWR at 1466 m	Top Liste ~1832 mMD (1800 mTVD). Challenge to cut and pull 9 5/8" casing to or deeper than 1507 m in order to get good annulus cement	Pending log
A-29 A	Producer w/GL	7 liner	job with losses	no	Based upon 49m³ cmt pumped, leaving 416 l in shoetrack and loosing 19,6m³ cmt to formation during displacement. Expected OH sizes: 8½" OH between 3839-3790m and between 2982-2445m, 9½" OH between 3790-2982m. TOC 121m over top Ness fm.	yes	Log cmt in 7" liner area because 1st and 2nd barrier will be in the same section	Pending log	9 5/8 casing		good job no losses	no	TOC from 12 1/4" OH at 1869 m.	Top of Liste ~2037 mMD (1800 mTVD)	Pending log
A-41 A	Producer w/GL	7 liner	job with losses	no	loss 10 m3 while displacing. No cement return after circulate above top of liner.	yes	Log cmt in 7" liner area because 1st and 2nd barrier will be in the same section	Pending log	12 1/4 annulus	12 1/4 annulus	good job no losses	no	Estimate TOC in gauge hole 2000 m (TOC from FWR 1917 mMD). Small pressure build up in B annulus. Plug not bump.	Top of liste ~1933 mMD (1800 mTVD)	Yes

		Reservoir Plug							Lista Formation Plug						
Well	**Type**	**Plug location**	**Cemented ok?**	**CMT logged?**	**CMT comment**	**CT Possible**	**Comment**	**External job needed?**	**3 rd Plug location**	**4th plug location**	**Cemented ok?**	**CMT logged?**	**CMT comment**	**Comment**	**External job needed?**
A-30 A	**Producer w/GL**	7 liner	good job no losses	no	liner was roated throughout the job but getting negative pressure test of liner packer. Half of spacer in return. Unable to test well after cmt job due to possible TSP leak.	yes	Log cmt in 7" liner area because 1st and 2nd barrier will be in the same section	Pending log	12 1/4 annulus	12 1/4 annulus	good job no losses	no	FWR TOC 2528 m	Top of Liste ~2158 mMD (1800 mTVD)	Yes
A-35 B	**Producer w/GL**	7 liner	job with losses	no	FWR TOC at 4877 m. (calculated from pressure level off after 18 m3 of cement out of	no	Due to total loss during cement job so the possibility for CT is quite low. Log cement in 7" liner to identify plug	Pending log	9 5/8 casing		good job no losses	no	FWR/Theoretical TOC 2000 m.(12 1/4" OH size TOC = 1732 m)	Top of Liste ~2071mMD (1800 TVD)	Pending log
A-22 A	**Producer w/GL**	7 liner	good job no losses	no	observed cement in return	yes	Log cmt in 7" liner area because 1st and 2nd barrier will be in the same section	Pending log	9 5/8 casing		good job no losses	no	FWR TOC1671 m. Plug was bump with 95% effeciency but pressure leak off.	Top of Liste ~1863mMD (1800 TVD) there is enough interval for cement plug	Pending log
A-7 C	**Producer w/GL**	7 liner	good job no losses	no	liner was roated throughout the job	yes	Log cmt in 7" liner because 1st and 2nd barrier will be in the same section	Pending log	13 3/8 casing		n/a	no	TOC 1300 m	Cut & pull 9 5/8" to 1713 m.or deeper. Then log 13 3/8" for annulus cement	Pending log
A-6 A	**Producer w/GL**	7 liner	good job no losses	no	FWR TOC at 3356 m. No cement in return. Roatate liner through out the job.	yes	Log cmt in 7" liner area because 1st and 2nd barrier will be in the same section	Pending log	13 3/8 casing		n/a	no	FWR TOC 675 m	Cut & pull 9 5/8" to1672 m.or deeper. Then log 13 3/8" for annulus cement(challenge because of 9 5/8" casing TOC from	Pending log
A-23 B	**Producer w/GL**	9 5/8 casing	job with losses	yes	TOC at 3404 m	no	*FWR loss 73 m3 during displacing cement, CBL showed not good cement for all interval. Small pressure build up in B-annulus	Yes	13 3/8 casing		n/a	Yes	Good TOC 1740 m	Top of Liste ~2188mMD (1800 TVD) there is enough interval for cement plug	no
A-40 D	**Producer SFLL**	7 liner	good job no losses	no	Theoretical TOC at 4140 m. No cement in return	yes	Log cmt in 7" liner area because 1st and 2nd barrier will be in the same section	Pending log	12 1/4 annulus	12 1/4 annulus	good job no losses	Yes	Top of fair cement at 3237,5 m Plug not bump	Top of Liste at ~2089 mMD (1800 mMD)	Yes
A-2 B	**Producer SFLL**	7 liner	job with losses	no	cement through EZSV for 2nd attempt	no	Maybe need to log in order to confirm plug location	Yes	12 1/4 annulus	12 1/4 annulus	good job no losses	no	Foam cement with some gain after displacement, Theoretical TOC at 1388 m	Top of Liste at ~1931 mMD (1800 mMD)	Yes
A-17 B	**Producer SFLL**				under								under construction		
A-33	**Producer SFLL**				under								under construction		
A-20 B	**Producer SFLL**	9 5/8 casing	job with losses	yes	Last 10 m3 of slurry was pumped with only 30% returns. USIT/CBL TOC =	no		No	9 5/8 casing	13 3/8 casing	n/a	Yes	9 5/8" USIT/CBL 1730 mMD; 13 3/8 USIT/CBL TOC 326 mMD	Top of Liste at ~1883 mMD (1800 mMD)	no

		Reservoir Plug							Lista Formation Plug						
Well	Type	Plug location	Cemented ok?	CMT logged?	CMT comment	CT Possible	Comment	External job needed?	3 rd Plug location	4th plug location	Cemented ok?	CMT logged?	CMT comment	Comment	External job needed?
A-15 DT	Producer SFLL	7 liner	good job no losses	no	Theoretical TOC at 2384 m. cement in return. Got cement and spacer in return when circulateing clean above liner.	yes	Log cmt in 7" liner area because 1st and 2nd barrier will be in the same section	Pending log	13 3/8 casing		n/a	no	Log 9 5/8" casing for top of good cement. Good cement at bottom part. Recheck 13 3/8" casing log again.	Top of Liste ~1852mMD (1800 TVD)	Pending log
A-18 D	Producer SFLL	7 liner	good job no losses	no	Theoretical TOC at 3375 m. cement in return. Roatde liner through out the job. Got some spacer return.	yes	Log cmt in 7" liner area because 1st and 2nd barrier will be in the same section	Pending log	9 5/8 casing		good job no losses	no	Theoritical TOC 1417 m	Top of Liste ~1898 mMD (1800 TVD)	Pending log
A-24 A	Producer SFLL	7 liner	good job no losses	no	Theoretical TOC at 2605 m. cement in return. Liner was roated through out the job.	yes	Log cmt in 7" liner area because 1st and 2nd barrier will be in the same section	Pending log	13 3/8 casing		job with losses	no	Loss 15 m3 during displacement. TOC 450 m	Top of Liste ~1976 mMD (1800 TVD)	Pending log
A-27 C	Producer SFLL	7 liner	job with losses	no	No cement	no	Do not need log because no cement behind 7" liner	Yes	12 1/4 annulus	12 1/4 annulus	job with losses	Yes	USIT TOC 2890 m loss 50m3 mud during displacement	Top of Liste ~2413 mMD (1800 TVD)	Yes
A-28 A	Producer SFLL	5 1/2 liner	good job no losses	no	Theoretical TOC at 3450 m. Liner: 5.5" x 7" tapered string. Plug did not bump. Flag on cement head confirmed dart was released. Observed no pressure spike when pumping, that indicated the WP has been released. Had full return all through the cementing operation. No losses. got some spacer on top of liner	yes	Log cmt in 7 x 5 1/2" liner area because 1st and 2nd barrier will be in the same section	Pending log	12 1/4 annulus	12 1/4 annulus	good job no losses	no	Theoritical TOC 2300 m	Top of Liste ~2062 mMD (1800 mTVD) Log cement for plug location	Yes
A-31 A	Producer SFLL	7 liner	job with losses	no	loss 22,7 m3 while displacing cement but got back from baloon effect	yes	Log cmt in 7" liner area because 1st and 2nd barrier will be in the same section	Pending log	13 3/8 casing		job with losses	no	Loss 8,2 m3 during displacement. TOC 1618 m	Top of Liste ~1886 mMD (1800 TVD)	Pending log
A-32 B	Producer SFLL	7 liner	good job no losses	no	observed cement in return. Rotated liner during cement job with and for the first 2800 strokes of cement diplacement wit 20 rpm. Torque gradually increased from initially 16 knm to a maximum of 33 knm (max allowed) where string stopped	yes	Log cmt in 7" liner area because 1st and 2nd barrier will be in the same section	Pending log	13 3/8 casing		n/a	Yes	CBL TOC 1125 mMD	Cut and pull 9 5/8" casing deeper than 1605 mMD. Top of Liste ~2169 mMD (1800 TVD)	no
A-34 C	Producer SFLL	9 5/8 casing	good job no losses	no	Top plug was not bump	no	Log cmt in 9 5/8" casing area because 1st and 2nd barrier will be in the same section	Pending log	13 3/8 casing		good job no losses	no	theoretical TOC at 1642 m. Ref. DBR Report 3/8/1996 full return during cement job.	Top of Liste at ~2009 mMD (1800 mTVD)	Pending log

Appendix D: Data sheet

Utstyr								Kjemikalier				
Supplier	Tools	Engineer per day	Operator per day	Day rate	Run charge	Fixed price	Approx tool sum	Supplier	Product	Engineer per day	Price / liter	
Baker	N-1 plug	16 234		2 302				Ramex	RX-72		77	(7,7 GBP)
	ASV punch			1 967		997		SLB	Ultralube		108	
Halliburton	EV0/TR1	14 296		4 063	40 626		300 000	SLB	TEG		11,23	
	CBL/CAST-M			11 156	711 540	164 016	1 000 000	SLB	MEG		9,23	
Interwell	ME plug	14 850		7 500	31 950		300 000					
	Cement retainer (add to plug)			5 000	31 950		280 000					
	Pump open (add to plug)						152 000					
	HEX plug			12 125	68 000	844 100	1 200 000					
	HET plug			11 775	95 000	1 268 700	1 600 000					
	Gauge			3 500	9 500	315 000	350 000					
	Gauge Hanger			12 363	38 800	438 900	650 000					
	HST			9 825	19 500		120 000					
	EST			8 625	19 500		110 000					
	Pulling tool			3 375								
SLB	RST	15 288	9 786	2 874	126 000		200 000					
	Caliper			2 874	100 000		200 000					
	PowerJet			9 000	30 000		150 000					
	PowerCutter			2 328	126 432		150 000					
	Install plug			810	33 000		50 000					
	CBL/USIT			6 612	366 642		600 000					
Aker	DectCutter	13 144		22 500	298 200		550 000					
	RCT cutter			4 368	170 766		220 000					
	Optis kamera			25 200	159 000		420 000					
Archer	SpaceTool	16 128		58 111	377 105		1 000 000					

Appendix E: Weatherford pulling and jacking unit

Weatherford

Weatherford Decommissioning
Intervention & Well Abandonment Product Line

DH-200/600 Generation II Pulling and Jacking Unit 3, 4, 5

The DH-200/600 Generation II Pulling and Jacking Unit represents the third system to address offshore intervention and well abandonment project needs. Unit 3 has been designed to API 4 F specifications and stamped accordingly. The Unit utilizes innovative equipment, technologies and resources to safely and efficiently address the requirements and challenges associated with offshore operations. The design is mobile, has a small footprint, is lightweight compared to the pulling capacity of the hoisting equipment, and utilizes an innovative self-clamping skidding system to access multiple wells without the need to rig down any of the main system components. The DH-200/600 Generation II Pulling and Jacking Unit has incorporated a gantry lifting system to handle and maneuver tubulars.

Pulling System

Pulling Capacity: 220,000 lbs
Pulling Stroke: 60 ft (nominal)
Max Operating Wind: 60 knots

The pulling system utilizes a single 30 ft. stroke hydraulic cylinder encapsulated within a telescoping mast. The hoisting cable system is connected to a load cell and rocker arm leveling system on one end and pass over a crown assembly. A swivel bail is utilized on the other end of the system with conventional links and an elevator. A power swivel can easily be incorporated into the system.

Jacking System

Jacking Capacity: 600,000 lbs
Jacking Stroke: 5 ft

This system consists of a four cylinder jack with upper and lower split bowls and a false rotary jacking floor. The Jack is fully removable from the system to allow for quick repair / replacement if necessary.

Racking System

Drill Pipe Size: up to 3-1/2 in. pipe
Length: up to 10,000 ft. pipe, Range 2
Weight: up to 160,000 lbs (80,000 lbs per side)

The Racking Towers are oriented on either side of the well and are joined by a gantry to help resist environmental loads and provide support during pipe handling. The gantry supports a trolley which can be used to assist the Derrickman in maneuvering tubulars into the storage position. Each row of pipe is contained with locking tabs. If necessary, provisions are included for racking a number of drill collars in the front of the Racking Tower.

Hydraulic Power Unit

Engine: 800 hp Cummings QSK-19
Classification: Class 1, Division 2
Hydraulic Capacity: 1,000 gallons
Diesel Capacity: 300 gallons (12 hour run time)
Pumps: 4 Pumps for Main Lifting System
Fluid: Enviro-Rite 46

The HPU system consists of an engine frame and pump frame which are coupled together on location with a removable driveshaft to minimize shipping weight and facilitate transport.

Riser and Main Beams

Beam Risers: 9 ft. high x 12 ft. wide
Main Beams: 54 ft. long x 51 in. high x 24 in. wide

Two Beam Risers are utilized to support the Main Beams and allow for clearance of the BOP stack. The Main Beams are positioned to provide a 5 ft. opening and allow clearance for the Annular. A Mezzanine Walkway traverses the outer sides of both Main Beams in order to allow easy access to mounting bolts for the above systems.

Power Swivel

Maximum Torque: 8,100 ft-lbs
Maximum Speed: 150 rpm

A Logan PS120 Power Swivel can be supported by the pulling system and utilized for standard downhole operations including cutting, milling, reaming, washover and drilling.

Specification

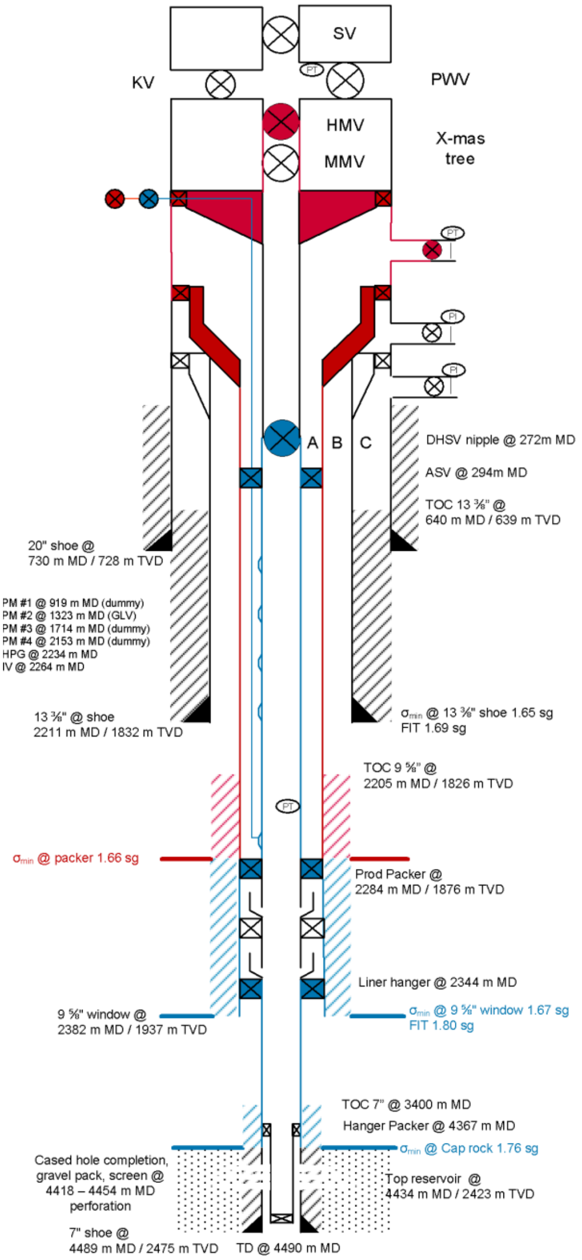
Total Weight of Unit (w/o tubulars) on Platform Beams:	230,000 lbs
Total Weight on Main Beams:	145,000 lbs
Estimated Truck Loads to Transport:	16 each
Assembly / Disassembly Time:	60 hours
Hurricane Evacuation Time:	24 hours

Weatherford Decommissioning
1028 Maurice Road
Broussard, LA. 70518
Tel: (337) 364-3834

Appendix F: Well barrier Schematic A-17-B

WELL BARRIER SCHEMATIC

As built



Well data			
Installation/Field name:		Statfjord A	
Well no:	33/9-A-17 B	Completed date:	10.05.2009
Well type:		Oil producer with gas lift	
Well design pressure:		345 bar	
Revision no:	1.01	Date:	21.02.2011
Well status:		Operating	
Prepared:		Jan Egil Asbjørnsen	
Verified:		Olav Skjæveland	

Well barrier elements	Ref. WBEAC tables	Verification of barrier elements
PRIMARY		
Formation at Cap rock	n/a	σ_{min} 1.76 sg Method: field model
7" liner cement	22	Length: 1034 m MD > top perf Method: see note 1
7" liner	2	PT: 345 bar with 1.50 sg (DBR 16.06.2008)
7" liner top hanger packer	43	PT: 345 bar with 1.50 sg (DBR 16.06.2008)
Formation at 9 5/8" production casing window	n/a	σ_{min} 1.67 sg Method: field model
9 5/8" Production casing cement (below packer)	22	Length: 177 m MD > window Method: USIT, see note 2
9 5/8" Production casing (below packer)	2	PT: 345 bar with 1.52 sg (DBR 23.05.2008)
Production packer	7	PT: 345 bar with 1.03 sg (DBR 31.05.2009)
SPM's (GLV, dummy)	29	PT: 80 bar with 1.03 sg (DBR 02.06.2009)
Production tubing	25	PT: 345 bar with 1.03 sg (DBR 10.05.2009)
Chemical injection line Inner needle valve	8	PT: 345 bar (DBR 09.05.2009) IT: 335 bar (DBR 31.05.2009)
DHSV Control line	8	IT: 83 bar (DBR 03.06.2009) PT: 520 bar (DBR 10.05.2009)
ASV Control line	9	IT: 175 bar (DBR 10.05.2009) PT: 520 bar (DBR 10.05.2009)
SECONDARY		
Formation at Prod packer	n/a	σ_{min} 1.66 sg Method: field model
9 5/8" Production casing cement (above packer)	22	Length: 79 m MD > packer Method: USIT, see note 2
9 5/8" Production casing (above packer)	2	PT: 345 bar with 1.03 sg (DBR 09.05.2009)
9 5/8" Casing hanger with seal assembly	5	PT: 345 bar (DBR 31.05.2009)
WH/Annulus valve	12	PT: 345 bar (DBR 31.05.2009)
Tubing hanger with seals	10	PT: 345 bar (DBR 31.05.2009)
WH/X-mas tree Connector	33	PT: 345 bar (DBR 31.05.2009)
Tubing hanger neck seal	10	PT: 345 bar (DBR 31.05.2009)
X-mas tree valves	33	PT: 345 bar (DBR 31.05.2009)

Notes:

1. 7" TOC Method: Theoretical 3400m MD from DBR 15.06.2008.
2. 9 5/8" TOC Method: Good cement quality from 2205 to 2300m MD according to USIT log 14.03.08.
3. 13 3/8" TOC Method: Old Matrix.

Risk Status Code marked (X):

				X	

Risk code BARREDC:

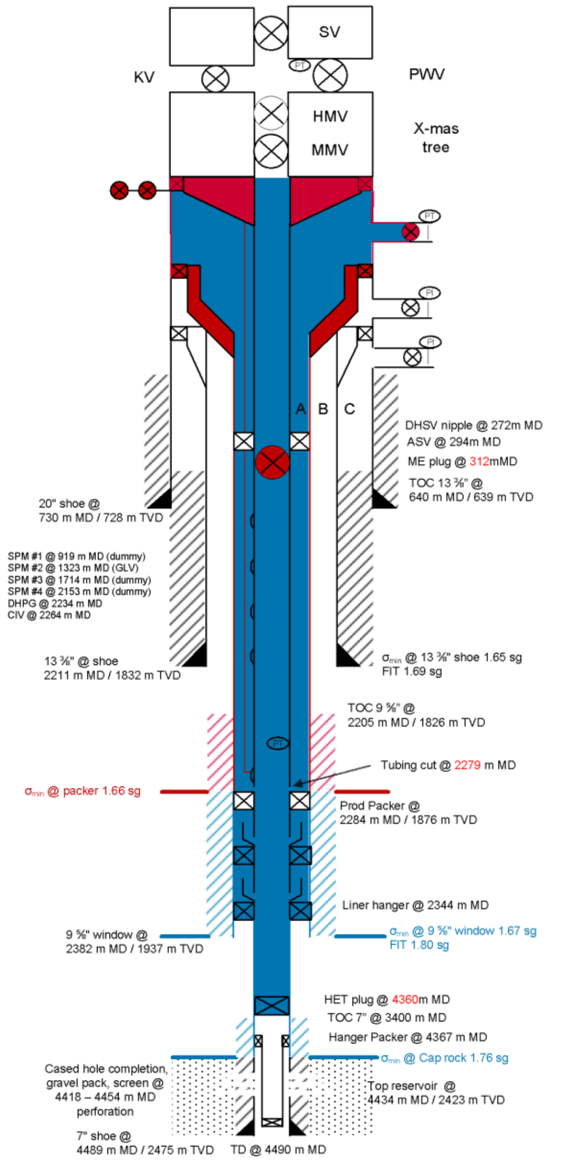
1. Formation at 13 3/8" exit has too low min horizontal stress to sustain Gas Lift Pahh (Pressure annulus high high) with gas gradient.
2. 13 3/8" csg do not have premium threads.
3. Due to gas lift in A-annulus, the primary and secondary barriers are not completely independent.

Disp. no. well integrity	Comment
88698	Automatical shut-down of gas lift is not according to IEC61508 / IEC61511 (valid to 01.02.2012)
90084	Temporary exception from K-11332 (valid to 01.07.2012)
83998	Disp for not using qualified CIV (valid to 31.12.2012)
83983	Disp from offshore testing of chemical inj valve.
83533	Use of NPT instead of BSP in well control hydraulic system.
30924	Disp from simulation of blow out rate.
46874	Disp from 2 relief-well well-paths for each well.
96964	Lekkasje forbi tetninger og testeplugger

Appendix G: Well barrier schematic after preparations

WELL BARRIER SCHEMATIC

After operation



Well data			
Installation/Field name:		Statfjord A	
Well no:	33/9-A-17 B	Completed date:	10.05.2009
Well type:		Oil producer with gas lift	
Well design pressure:		345 bar	
Revision no:	1.01	Date:	10.01.2012
Well status:		Operating	
Prepared:		Ingvar Egeland	
Verified:		Pætur Danielsen	

Well barrier elements	Ref. WBEAC tables	Verification of barrier elements
PRIMARY		
Formation at Cap rock	n/a	σ_{min} 1.76 sg Method: field model
7" liner cement	22	Length: 1034 m MD > top perf Method: see note 1
7" liner	2	PT: 345 bar with 1.50 sg (DBR 16.06.2008)
7" liner top hanger packer	43	PT: 345 bar with 1.50 sg (DBR 16.06.2008)
Formation at 9 5/8" production casing window	n/a	σ_{min} 1.67 sg Method: field model
9 5/8" Production casing cement (below packer)	22	Length: 177 m MD > window Method: USIT, see note 2
9 5/8" Production casing (below packer)	2	PT: 345 bar with 1.52 sg (DBR 23.05.2008)
Production packer	7	PT: 345 bar with 1.03 sg (DBR 31.05.2009)
Inj.water	1	10bar overbalance
HET plug	6	See program
SECONDARY		
Formation at Prod packer	n/a	σ_{min} 1.66 sg Method: field model
9 5/8" Production casing cement (above packer)	22	Length: 79 m MD > packer Method: USIT, see note 2
9 5/8" Production casing (above packer)	2	PT: 345 bar with 1.03 sg (DBR 09.05.2009)
9 5/8" Casing hanger with seal assembly	5	PT: 345 bar (DBR 31.05.2009)
WH/Annulus valve	12	PT: 345 bar (DBR 31.05.2009)
Tubing hanger with seals	10	PT: 345 bar (DBR 31.05.2009)
WH/X-mas tree Connector	33	PT: 345 bar (DBR 31.05.2009)
Tubing hanger neck seal	10	PT: 345 bar (DBR 31.05.2009)
X-mas tree valves	33	PT: 345 bar (DBR 31.05.2009)
DHSV Control line	8	IT: 83 bar (DBR 03.06.2009) PT: 520 bar (DBR 10.05.2009)
ASV Control line	9	IT: 175 bar (DBR 10.05.2009) PT: 520 bar (DBR 10.05.2009)
Production tubing (above DHSV)	25	PT: 345 bar with 1.03 sg (DBR 10.05.2009)
Chemical injection line Inner needle valve	8	PT: 345 bar (DBR 09.05.2009) IT: 335 bar (DBR 31.05.2009)
Tubing hanger	10	PT: 345 bar (DBR 31.05.2009)
ME plug	6	See program

Notes:

1. 7" TOC Method: Theoretical 3400m MD from DBR 15.06.2008.
2. 9 5/8" TOC Method: Good cement quality from 2205 to 2300m MD according to USIT log 14.03.08.
3. 13 3/8" TOC Method: Old Matrix.

Risk Status Code marked (X):

			X	

Risk code BARREDC:

1. Formation at 13 3/8" exit has too low min horizontal stress to sustain Gas Lift Pahh (Pressure annulus high high) with gas gradient.
2. 13 3/8" csg do not have premium threads.
3. Due to gas lift in A-annulus, the primary and secondary barriers are not completely independent.

Disp. no. well integrity	Comment
88698	Automatical shut-down of gas lift is not according to IEC61508 / IEC61511 (valid to 01.02.2012)
90084	Temporary exception from K-11332 (valid to 01.07.2012)
83998	Disp for not using qualified CIV (valid to 31.12.2012)
83983	Disp from offshore testing of chemical inj valve.
83533	Use of NPT instead of BSP in well control hydraulic system.
30924	Disp from simulation of blow out rate.
46874	Disp from 2 relief-well well-paths for each well.
96964	Lekkasje forbi tetninger og testeplugger