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Abstract

The number of wells to be abandoned on the Norwegian Continental Shelf will increase in the forthcoming years. As a consequence, significant expenditures will be required paid by the individual companies, the state and the society. Despite many technological advances in the oil and gas industry the recent years, traditional P&A of platform wells is still particularly performed by using expensive drilling rigs. In an industry characterized by time-consuming, costly, and complex operations, it is especially interesting to investigate the technological potential of P&A and possible cost-savings this may entail. This thesis therefore considers rigless P&A of platform wells, where the use of well intervention equipment is presented as an alternative approach to traditional rig-based P&A.

Three different case studies of P&A are explored and presented: a rig-based approach, a rigless approach, as well as a combination of rig-based and rigless approach. Well intervention equipment such as wireline and a hydraulic jacking unit are involved in the emerging, rigless method. In order to suggest the most appropriate and cost-efficient abandonment approach, three models are built and used in a Monte Carlo simulation to forecast cost and duration of the different P&A operations. By using well intervention equipment, risk and uncertainties related to unpredictability in the rig marked is removed, which simplifies the time and cost forecasting. To achieve accurate estimation of cost and duration, data is collected with awareness. Historical data, particularly from Aker BP, as well as expert opinions and knowledge, are thus used as simulation input to produce realistic forecasts. The simulation output of the different models is compared, discussed and evaluated using the percentile output values. Findings from the case studies identifies that rigless P&A is much more time-consuming than rig-based P&A. However, partly reducing and completely removing the rig scope leads to significant cost-savings. Since the chosen simulation models consider P&A of a single well, this opens an opportunity for further research within time and cost simulation for multiple wells on platforms.

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Abbreviations

BOP	Blowout preventer
CDF	Cumulative distribution function
DDU	Double drilling unit
DP	Drilling platform
HP	High pressure
MAX	Maximum
MIN	Minimum
MINV	Maersk Invincible
ML	Most likely
NCS	Norwegian Continental Shelf
N/D	Nipple-down
NPT	Non-productive time
N/U	Nipple-up
P&A	Plug and abandonment
P&Aed	Plugged and abandoned
PDF	Probability density function
PWC	Perforate, wash, cement
SOI	Source of inflow
WBS	Well barrier schematic
WI	Well intervention
WOW	Waiting on weather
XMT	Christmas tree

1 Introduction

1.1 Motivation

On the Norwegian Continental Shelf (NCS), the first wellbores were drilled in the 1960's and this became the beginning of what is today Norway's largest industry (Norwegian Petroleum, 2021). The production from oil and gas reservoirs is not an infinite process, and a well's life cycle includes planning, drilling, completion, production, and abandonment. All wells reach the end of their life, and the authorities then require the wells to be permanently plugged and abandoned (P&Aed). The definition of plug and abandonment (P&A) implies to seal a well for production and aims to avoid contamination of the environment outside the well, migration and cross-contamination of gas and flow sources in the well, and prevent leakage to surface in and out of the well (Aarlott, 2016).

Today it is clear that the planning and facilitation for future P&A has not been a priority in the planning phase of most wells on the NCS. For instance, there is a lot of missing and valuable information about the geological formations that could have been available if the wellbores had been logged and thoroughly researched in the earliest phases of their life cycle. Without such information, the abandonment phase becomes more complex and expensive.

Another challenge is that the costs of abandonment operations can be challenging to predict and forecast. Traditionally, P&A operations are performed using drilling rigs with high daily rental costs. Rig rates are very sensitive to marked changes, and especially to changes in the oil and gas prices (Osmundsen et al., 2013). Consequently, being dependent and affected by the rig market can lead to big gaps between the planned abandonment costs and the actual abandonment costs. Considering this, P&A operations might become more flexible and predictable without such fluctuations and the need of a drilling rig.

P&A operations are very time consuming, costly and have probably been a slightly neglected focus area in the past. Despite many technological advances in the oil and gas industry in recent years, history shows that traditional P&A methods have had less technological progress. As the oil companies are committed to plug their wellbores, the Norwegian tax regime is regulated in a way that makes the state pay 78% of the P&A

expenses (Jacobsen, 2012). This means that the Norwegian state pays enormous costs every year for abandonment operations, and these costs are covered by the taxpayers in our society. Finding cost-efficient and safe methods for P&A will therefore be of great value and importance to both the industry and the society. The number of wells to be abandoned will increase in the forthcoming years as aging fields reach their economic and productive limits, and the development of more efficient technology that can cut down P&A expenses should therefore be of high priority.

According to Factpages Norwegian Petroleum Directorate (2021) in May 2021, currently a total of 7270 wellbores have been drilled on the NCS. Of these, 5315 are development wellbores, which includes injection, observation, and production wells. Approximately 507 of the development wellbores already have the status "junked" or "P&A", which means that with today's number approximately 4808 wellbores will be P&Aed in the future (Factpages Norwegian Petroleum Directorate, 2021). The development wellbores are divided into platform wellbores and subsea wellbores. As illustrated in figure 1.1, the amount of platform wells that require P&A in the future is greater than subsea wells, and it is therefore decided to focus on P&A approaches for development platform wells in this thesis.

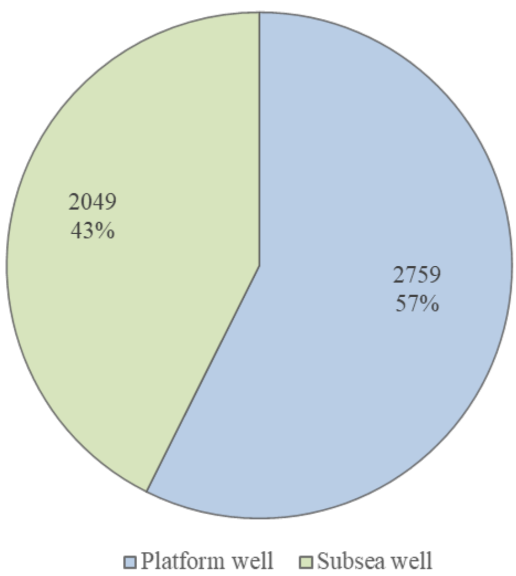


Figure 1.1: Approximate number of subsea and platform wells requiring future P&A. (Factpages Norwegian Petroleum Directorate, 2021)

1.2 Research Question

Based on the above discussion of the need for innovative and cost-efficient solutions for P&A in the industry, the following research question is formulated:

To what extent can well intervention technology reduce rig scope and perform sustainable and cost-efficient platform abandonment operations?

In order to answer this research question, three different platform well abandonment approaches, with associated cost and duration, will be explored throughout this thesis: a rig-based "case A" approach, a rigless "Dream Well" approach, as well as a combination of rig-based and rigless "case B" approach. These will be referred to as case studies, as presented in table 1.1. A new P&A method, where well intervention technology such as wireline will be taking over parts of, and the entire, traditional rig work relating to platform wells will be investigated. Further, a rigless recovery system, called WellRaizer, which is based on a hydraulic jacking principle, will be presented as for the first time in a scientific thesis. In addition to time and cost, environmental and societal factors and impact related to P&A will also form a fundamental part of the discussion.

By using the three abandonment approaches, models will be constructed and used in a Monte Carlo simulation that will produce time distribution curves for the operations. As table 1.1 shows, the P&A operations will be divided into four phases for each case study, and the Monte Carlo simulation outcome will provide details regarding cost and duration for each phase. The specific technology and operational method that is used in each phase will be presented and explained throughout this thesis. All case studies will provide a comparable relationship as the same fictitious well is P&Aed, and the simulation results will therefore be able to suggest the most appropriate approach to platform P&A.

One reason why Monte Carlo simulation is the chosen model to provide estimates for this thesis is that uncertainty and learning effects can be built into the simulation model. The objective of the simulation is to provide a realistic time and cost potential for the various P&A approaches. To achieve as accurate estimates as possible, it is crucial to be critical and aware during data collection. Mainly data and experiences from P&A operations at Aker BP's Valhall Drilling Platform (DP) field will be used throughout the case studies to discuss the performance of the different methods. Abandonment data from

Halliburton's Jotun B field will also be used, as well as expert opinions and knowledge within the industry. With this data as a basis for correct estimation of the operational time and cost, this thesis will try to determine to what extent the different procedures are able to reduce future challenges, rig scope and costs of P&A operations.

Table 1.1: Chosen case studies for P&A of a platform well

Phase	**Case A**	**Case B**	**Dream well**
Phase 0 Preparatory work	Rig	Well Intervention	Well Intervention
Phase 1 Reservoir abandonment	Rig	Rig	Well Intervention
Phase 2 Intermediate abandonment	Rig	Rig	Well Intervention
Phase 3 Conductor and wellhead removal	Rig	Well Intervention	Well Intervention

2 Background

2.1 Definition of Plug and Abandonment

Abandonment of a wellbore implies to isolate the reservoir and other permeable pressure zones by establishing well barriers, where cement is conventionally used for well barrier plugs. P&A of wells is important in order to prevent future leaks of hydrocarbons to the surface and to avoid damaging the environment. This operation is crucial for both the industry, society and environment, and there are high requirements for the operational execution and result. The requirements to P&A are regulated by the Petroleum Act, and simply explain that the well must be completely without any source of leakage when abandoned (Petroleum Safety Authority Norway, 2021). If there is any leakage from the well after the abandonment, then the P&A operation will not be approved by the Petroleum Safety Authority in Norway.

P&A operations require a lot of planning as several factors can affect the productivity of the operations. For instance, an operation can be suspended due to waiting on weather or waiting on equipment. Cost, time and risk estimates and safety measures should therefore always be considered in advance of an operation, as well as a thorough understanding of the wellbore.

There are several sources of inflow (SOI) in a wells overburden, that needs to be isolated. Leakage of gas can lead to sustained casing pressure, which is a pressure that persistently rebuilds after bled-down (Sæby and Shell, 2011). In order to meet the required goals regarding P&A of wells, NORSOK standards developed by the Norwegian petroleum industry must be followed. According to NORSOK D-010 (2013), two qualified barriers must be installed to isolate the SOIs and form a well barrier envelope. The primary barrier is the first barrier against the SOIs, while the secondary barrier acts as a back-up barrier. This establish a double security in case the primary barrier fails. Further, the impermeable formations located above the reservoir and the SOIs will be referred to as seals. A well construction consists of several casing strings that are lowered into the wellbore and cemented in place. At the bottom of the casing string, a casing shoe will be present where the rounded bottom on the casing shoe facilitate running into the hole.

Figure 2.1 illustrates a wellbore with typical casing strings and their corresponding names, which will be referred to in this thesis. The space between two casing strings where fluid can flow, is called "annulus". A complete well is divided into several annuli where each annulus has its own unique name, such as A-annulus and B-annulus.

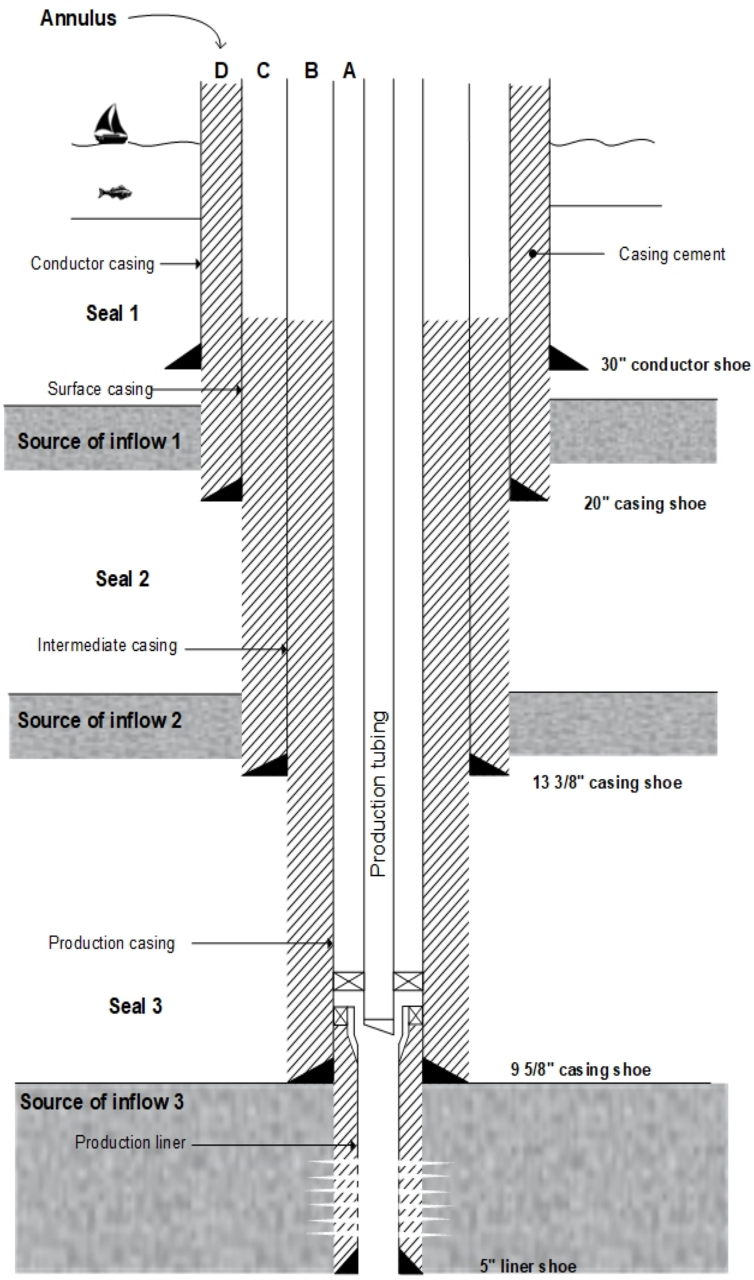


Figure 2.1: Example of a well construction.

We distinguish between two types of abandonment: temporary abandonment and permanent abandonment. In temporary abandonment, the well control equipment is removed and the well has been abandoned for a limited time period, but it shall be possible to re-enter the well after a planned period (NORSOK D-010, 2013). Permanent abandonment is when the well is plugged with an eternal perspective and the well will not be re-used or re-entered again (NORSOK D-010, 2013). This thesis will only consider operations and time and cost analysis for permanent plug and abandonment, and P&A is therefore referred to as permanent P&A.

2.2 Platform Well Design

The execution of P&A operations depends on the well type. When planning for abandonment of a platform well, it is crucial to review and understand the well design. For a platform well, the wellhead, christmas tree (XMT) and well control equipment will be located at surface on the production platform (Khalifeh and Saasen, 2020).

When recovering tubing and casing strings during abandonment operations, it is important to understand the wellhead design and the interaction between all casing strings and the wellhead. Wellhead housings are associated with the following main components: starting casing head, casing hanger, casing spool, tubing head, tubing hanger and tubing spool. Figure 2.2 illustrates some wellhead equipment associated with some casing strings.

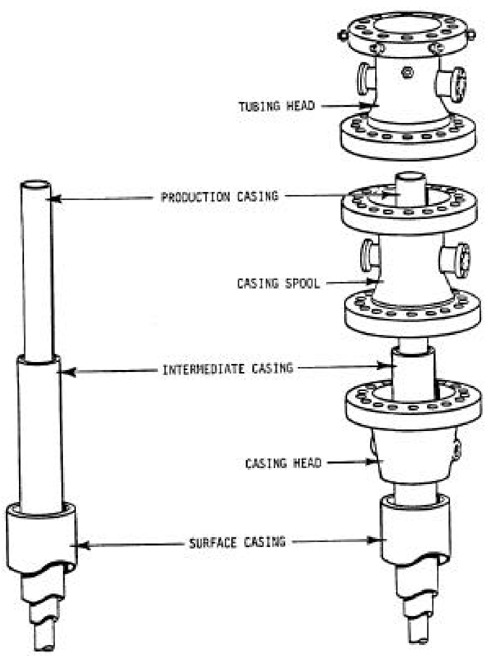


Figure 2.2: Wellhead housings associated with the various casing strings. (ABB Vetco Gray, 2003)

The conductor is the first casing string that is put into the well. A base plate is usually attached to the casing head and placed on top of the conductor (ABB Vetco Gray, 2003). The first wellhead component installed, the starting casing head, is installed on the surface casing, which is the first casing string that is cemented into the well (ABB Vetco Gray, 2003). Above all intermediate casing strings and the production casing, casing spools and tubing spools are installed, respectively. The function of casing spools is to hang off the next casing string, while the tubing spool is used to hang off the production tubing string. The production tubing is not illustrated in figure 2.2, but the tubing is also supported and sealed within the tubing spool inside the wellhead. Each casing string installed on a well is suspended and seal inside of the previously installed wellhead component by means of a casing or tubing hanger (ABB Vetco Gray, 2003). The tubing head supports the tubing string and tubing hanger.

Once the tubing head has been installed in the well, the top connector provides a connector for the XMT. The XMT is installed on top of the tubing head with a tubing head adapter and provides flow control of formation fluids from the well. As discussed earlier, there should always be two well barrier envelopes in place. The XMT will be disassembled several times during an abandonment operation, which means that another well control equipment must be rigged up. Therefore, when the XMT is disassembled, well control equipment, such as a blowout preventer (BOP), is assembled on the wellhead instead. The BOP works as a large valve and can effectively close if flow control from the well is lost. Assembly and disassembly of well control equipment is also referred to as "nipple-up" (N/U) and "nipple-down" (N/D) well control equipment in this thesis.

2.3 Phases of P&A

The operational sequence of P&A is normally divided into three phases, “Reservoir abandonment”, “Intermediate Abandonment” and “Wellhead and Conductor Removal” (Oil & Gas UK, 2015). The following subsections describe each phase reflecting the scope of work and the required equipment.

2.3.1 Phase 0 and 1

The first phase, "Reservoir Abandonment", aims to establish the well status and traditionally prepare for rig-based P&A. This phase also reflects preparatory work which will be referred to as phase 0 (Moeinikia et al., 2014b). Phase 0 is usually done rigless, by investigating the wellhead and rigging up a wireline unit. Chapter 4 provides further information about the wireline unit and how it operates during this phase. In phase 1, primary and secondary barriers are installed and isolates the reservoir sections of the wellbores from potential flow. The goal is to isolate the connection to the reservoir perforations through the inside of the wellbore.

Figure 2.3 illustrates a well barrier schematic (WBS) of a fictitious reservoir abandonment. In this case, a bridge plug is installed in the bottom of the tubing. A definition of bridge plugs will be provided in section 2.4. Further, the production tubing is cut and pulled, which is conventionally performed using a rig with a BOP installed. The tubing may be left in place, partly or fully retrieved (Oil & Gas UK, 2015). Both a primary and a secondary cement plug is then installed as qualified barriers for the reservoir.

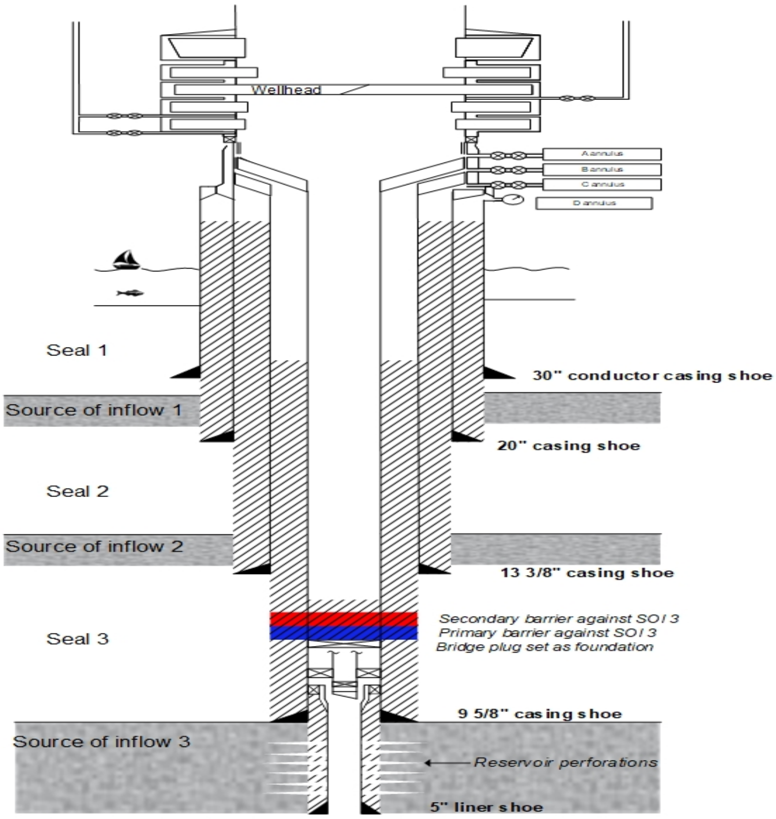


Figure 2.3: WBS with completed phase 0 and 1.

2.3.2 Phase 2

Phase 2 is defined as “Intermediate Abandonment” and aims to install barriers, both primary and secondary, above all the required SOIs to isolate permeable zones in the overburden with flow potential. Conventionally, this phase is rig-based and consists of operations such as casing retrieval and barrier setting. Phase 2 completes isolation of the well by setting an open hole to surface barrier below the seabed.

Figure 2.4 is a continuation of the previous WBS, illustrating a completed intermediate abandonment where no further plugging is required in this phase. A permanent primary and secondary barrier is installed above SOI 2 to ensure cross-sectional sealing, and a surface barrier is also installed.

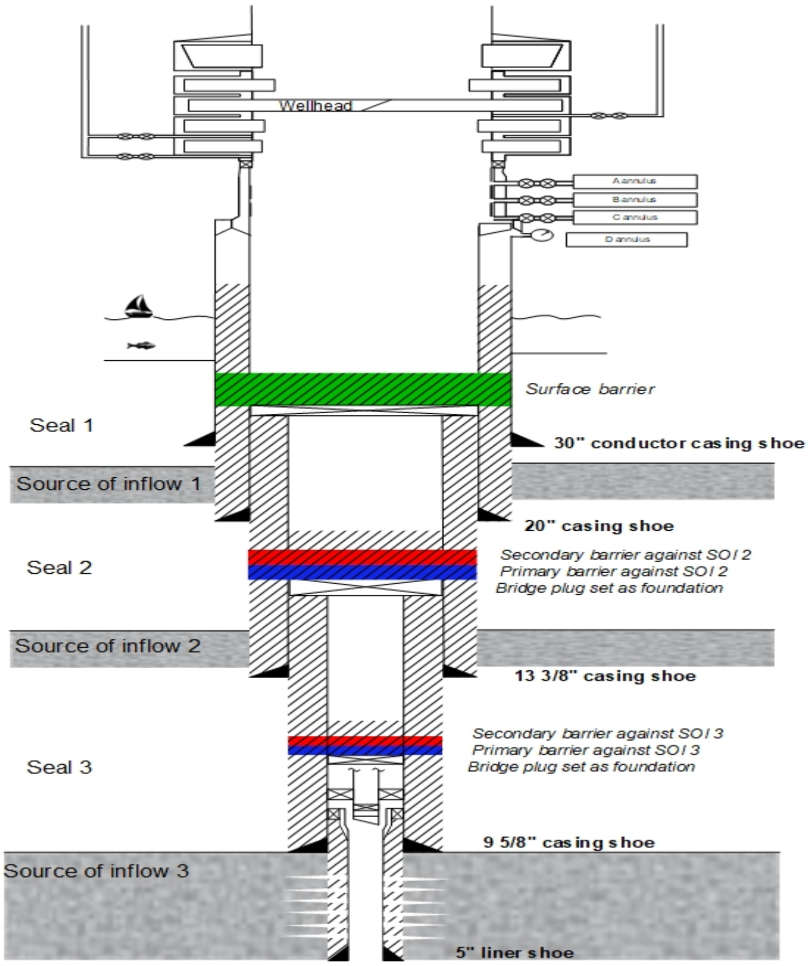


Figure 2.4: WBS with completed phase 2.

2.3.3 Phase 3

The third and last phase is the “Wellhead and Conductor Removal”, which includes cutting and retrieval of casing strings, conductor, and wellhead. Casings and conductors are cut and removed some meters below the seabed. Conventionally, these operations are performed with a rig. When phase 3 is complete, there is no further abandonment activities, and the well is permanently P&Aed, as illustrated in figure 2.5.

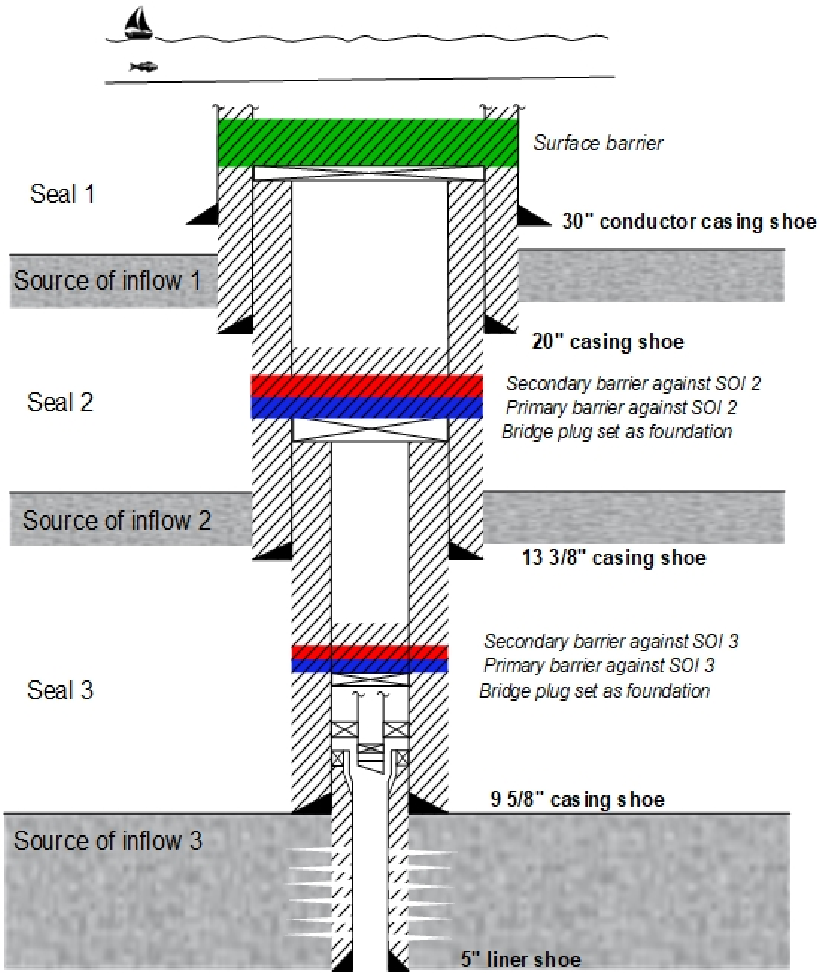


Figure 2.5: WBS with completed phase 3.

2.4 Operational Procedure of P&A

There exists several methods and approaches to well abandonment as the design and composition differs from one well to another, but the goal is to establish well barriers that provides sealing both vertically and horizontally (NORSOK D-010, 2013). The P&A operational procedure is unique for every well, even though there are some general sequences that characterize most operations. The following shortly summarizes a typical P&A procedure where the main operational steps are involved:

Prepare the well for P&A:

Prior to any activity, a vessel or a rig is normally mobilized to the well location. The wellhead and the XMT are investigated to ensure optimal functionality and safety throughout the operation. A wireline unit is rigged up on platform and a wireline functionality test is performed according to safety regulations.

The wireline unit performs a drift run and a caliper run which provides diagnostics and logs that evaluates the wellbore condition and the quality of the equipment down-hole. The log provides information about the tubing diameter and the potential amount of damage, scale and corrosion in the well.

Kill well:

Prior to the abandonment activity, the well must be killed. To kill the well, heavy kill fluid is pumped into the well. The heavy fluid ensures that the hydrostatic pressure is greater than the formation or pore pressure, and this shut off the flow into the wellbore (Halvorsen, 2016).

Cut and pull production tubing:

The tubing is cut with wireline above the production packer. Further, the annulus and tubing is displaced to kill fluid to verify optimal circulation and communication. It is necessary to cut and pull the production tubing in order to access the 9 5/8" production casing. We need fully access to the 9 5/8" casing in order to log and evaluate good or bad cement behind the casing. The information about the cement condition is essential when deciding the placement area of the cement plug barrier. According to NORSOK D-010 (2013), removal of downhole equipment is required as this can cause loss of well integrity, and control lines and cables shall not form part of the permanent well barriers. The tubing has normally control lines attached, and this provides an additional reason why it must be removed.

Platform wells are conventionally equipped with a vertical XMT. These XMTs are secured with primary and secondary barriers and the XMT can therefore be removed before the tubing is pulled (Moeinikia, 2016). To ensure and maintain well integrity and control during the tubing retrieval, a BOP is nippled up after nipple down the XMT.

Retrieval of the production tubing is a heavy lifting operation that requires large pulling force. Normally a rig performs this operation and further operations from this stage. For instance, during the P&A campaign at Valhall DP, a jack-up rig has been utilized to retrieve the tubing (Aker BP, 2017).

Establish primary and secondary barriers

A primary and secondary barrier is installed to ensure that the reservoir is sealed both vertically and horizontally. The number of permanent well barriers that is needed to establish full cross-sectional sealing of a well depends on the number of potential sources of inflow, throughout the well. As each well is unique, the number of SOIs and seals varies. Wells with many permeable, intermediate zones and big flow potential will therefore restore more seals than wells with fewer permeable intermediate zones.

Logging tools are run in order to determine the quality of the cement behind casings. If the logging data can verify good quality casing cement, then an internal cement plug can be installed inside the casing. If the logging data shows cement with poor quality or lack of casing cement, it is necessary to apply section milling or perforate, wash, cement (PWC) technology (Moeinikia, 2016). Figure 2.6 illustrates both a cement plug installed by using the PWC technology, as well as an internal cement plug. During this thesis' case studies, only the PWC method and internal cement barrier method for barrier installation will be used:

- **Internal cement plug:** If the log can verify good quality of the annular cement bond, an internal cement plug can be verified as barrier inside the casing. A common method to install cement barriers is to circulate drilling mud and pump cement through drill pipe or coiled tubing.
- **Perforate, wash, cement:** PWC jobs can be used when the log shows poor quality of the annular cement bond. This involves perforating the casing, cleaning the annulus behind the casing perforations, and pumping cement downhole and out through the perforations to establish a cement plug (Knutsen, 2019).

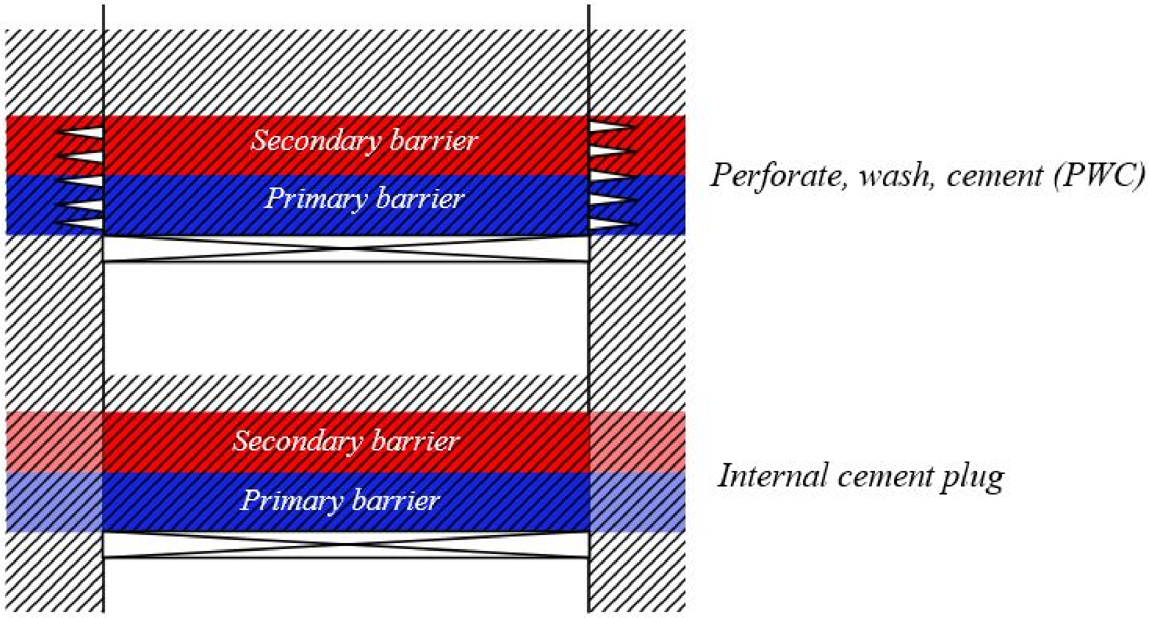


Figure 2.6: Illustration of two different approaches for barrier establishment.

It is not possible with today's technology to log through two casing strings, and it may become necessary to cut and pull the 9 5/8" production casing in order to access and log behind the 13 3/8" intermediate casing. If this is performed and the cement is proven solid, then a plug is installed inside the 13 3/8" intermediate casing. Bridge plugs are used as foundation for upcoming primary cement barrier and reduce the chance for cement contamination, as potential flow and pressure can enter from lower areas in the well (Halvorsen, 2016).

Install surface plug:

If there is no gas and flow potential from the formations via the C or D annulus, then it is sufficient to place a surface plug inside the 13 3/8" casing. If there is sustained casing pressure from C-annulus, it becomes necessary to cut and pull the 13 3/8" intermediate casing in order to log the 20" casing cement, and then establish a full cross-sectional cement barrier inside the 20" surface casing. If there is sustained casing pressure from the D-annulus, it might become necessary to cut and pull the 20" surface casing, in order to establish a full cross-sectional cement barrier inside the 30" conductor casing. The surface cement plug is the final well barrier.

Cut and retrieve conductor, casing strings and wellhead:

The final step of the P&A procedure is to cut and remove the conductor and casing strings, including the wellhead, a few meters below the seabed.

2.5 P&A Cutting Techniques

Cut and pull casing operations are necessary in situations where the annular barrier is poor or non-existent and where the casing strings overlap, as explained in the typical P&A procedure in section 2.4. Pipe retrieval requires large amounts of pulling force, and there exists several cut and pull tools and methodologies that can cut through multiple casing strings and solve challenges associated with this.

As mentioned earlier, it is common to cut production tubing with wireline. Other cutting operations can be performed using explosives, chemicals, mechanical cutters or abrasive cutters (Khalifeh and Saasen, 2020). Mechanical cutting or abrasive cutting is the preferred method for casing cutting (Moeinikia, 2016). Mechanical cutters are power-driven, while abrasive cutters are based on a sand cutting technique or a water jet cutting technique. For sand cutting, a high volume of abrasive particles are injected into a water jet and pumped at low pressure, while for water jet cutting, a low volume of abrasive particles are pumped at high pressure (Khalifeh and Saasen, 2020). To enhance the cutting performance, casing strings are conventionally under tension during the cutting operation.

In today's marked, there are several cutting tools with different functions, specifications, and benefits. Different equipment can perform cutting operations with significant differences in speed, and an example of this will be presented in the case study in section 6.2.

2.6 Literature Review

Currently, there is only a limited amount of information within the field of rigless P&A of platform wells, as most of the literature considers usage of intervention vessels for P&A operations of subsea wells. Searching for "rigless P&A" on Google Scholar only provides 58 search results. Therefore, this section will particularly present a brief overview of literature that is relevant for rigless P&A and have a focus on duration and cost estimation.

Wittberg (2017)'s research stands out by investigating P&A of platform wells, where an alternative approach to rigless P&A using well intervention equipment is presented. He concluded that combining intervention equipment such as wireline and coiled tubing with high energy P&A technology could be utilized for reservoir abandonment, while complex operations in a wells overburden should be plugged using a drilling rig. He further recommended to provide a time and cost analysis where the rigless approach is compared to a conventional P&A approach.

Mikalsen (2012) suggested an approach using a hydraulic pulling and jacking unit together with coiled tubing, instead of using a rig for platform P&A. Time and cost related to the P&A approach was provided and based on historical data, but without explicitly presenting the model used for the estimation. His results showed that the rigless method was less time-consuming, but had a much higher day-rate, than the conventional method. Nevertheless, he concluded that reduced operational time and personal would lead to a major overall cost saving that eventually would make the P&A campaign more cost-efficient using the rigless method.

Raksagati (2012) used Monte Carlo simulations to forecast cost and duration of several P&A approaches of subsea wells, both for single well P&A and for multi-well "batch" P&A. The major differences between his approaches was the application of rig or vessel technology, as well as a combination of rig and vessel technology. However, the results provided an insignificant difference in cost and duration between the rigless or rig-based method. Based on the findings, he nevertheless suggested a vessel-based approach for P&A in order to free rigs to perform drilling operations instead. In addition, he suggested to increase the number of wells in batch operations in order to reduce the cost of P&A per well. There are, to this thesis knowledge, little research and estimates of time and cost for rigless platform P&A. Therefore, to make the contribution of this thesis even more relevant, it could be interesting to perform a similar research approach for platform wells.

The importance of collecting reliable and a sufficient amount of data for accurate simulation and analysis is significant within the oil and gas industry. Moeinikia et al. (2014a) also used a Monte Carlo simulation approach to evaluate cost efficiency of rigless P&A for a subsea multi-well campaign. They used, for the first time, an approach that included learning curves, correlations, and possible risk events to evaluate time and cost of a subsea batch P&A. Findings from their studies showed that these factors had a significantly positive impact on cost and duration of the multi-well campaign. This makes it especially interesting to include expert opinions involving learning curves and risk for time and cost estimation within platform P&A in this thesis.

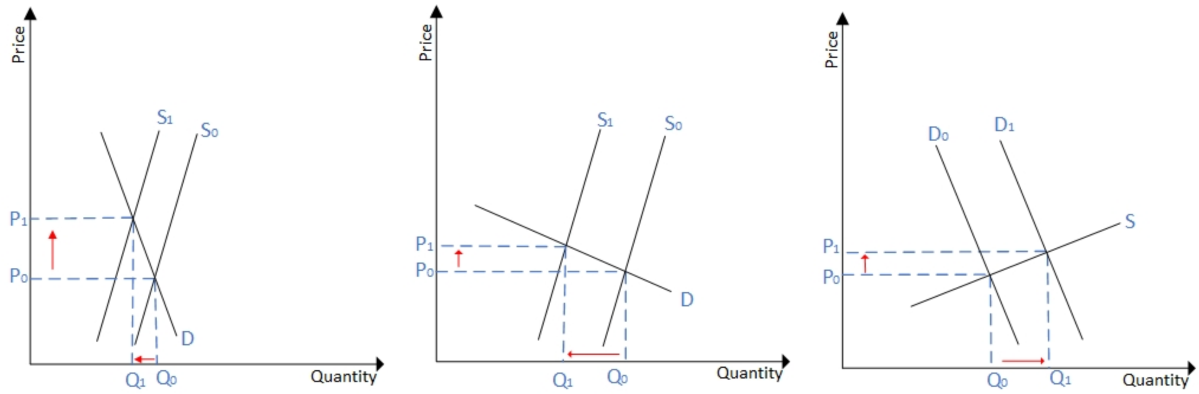
3 Understanding P&A Costs and Impact

3.1 Cost-Influencing Factors

Traditionally, P&A operations are performed using drilling rigs with high daily rates. The rig rates contribute to 40-50 percentage of the total costs of P&A, and thus affect the profitability of abandonment operations (Straume, 2016). Due to both unforeseen and foreseen changes in the oil and gas industry and the rig market, it is a challenge to predict future daily rig rates. For instance, as a response to Covid-19, the Norwegian parliament introduced several measures to secure the financial challenges, and the new tax regime provided incentives to stimulate the production drilling activity (Government.no, 2020). However, weak oil prices and an increased focus on renewable energy are causing cutbacks in exploration drilling activity. When estimating the costs of rig-based abandonment operations, it is crucial to understand the relationship between the rig rates and their influencing drivers, as this can improve budgeting and cost analysis.

The rig rates are sensitive to the oil and gas price in the market, and a change in supply and demand for oil and gas will lead to a shift in the oil and gas price, as shown in figure 3.1. In short terms, increased oil and gas price will not lead to any big change in consumer consumption as today's society is still very dependent on this form of energy supply. The demand for oil and gas is therefore inelastic as shown in figure 3.1a (Hannesson, 1998). This can also be confirmed in Osmundsen et al. (2013)'s study, where their econometric analysis implicated that the current oil and gas price has a weight of 6.9%, while the expected future price, which is assumed to influence the rig market, has a weight of 93.1%.

In long terms it is possible to find substitutes to oil and gas which means that a change in the oil and gas price can lead to a bigger negative shift in the demanded oil quantity. Considering this, the rig rates will probably decrease as a consequence. Meanwhile, increased prices for oil and gas can provide opportunities for new investments that will increase the supplied oil quantity. For instance, investing in new and efficient technology, higher storage and production capacities, and new oil fields can increase the volume of oil and gas. In long terms, both the demand and the supply for oil and gas can therefore be elastic, illustrated in figure 3.1b and 3.1c (Hannesson, 1998). Osmundsen et al. (2013) also provided an analysis for the long run price elasticity, indicating that a 10% permanent increase in the oil and gas price index would increase the rig rates by 12.3%.



(a) Inelastic demand **(b)** Elastic demand **(c)** Elastic supply

Figure 3.1: Graphs showing price elasticity of supply and demand for oil and gas.

Obviously, increased exploration and production in the oil and gas industry, as well as high expected oil and gas prices, will stimulate the rig market and increase the rig demand. Without the need of a rig for P&A operations, one can exclude a lot of uncertain factors related to rig rates and the rig market in the cost estimations. This thoroughly emphasize that it is easier to plan the costs for well abandonment if the operations are performed rigless, and that one probably can reduce the costs significantly by not using a rig.

3.2 Time-Cost Relationship

There is always a relationship between time and cost in a project, and several measures have been performed on the NCS regarding the time-cost relationship for P&A. A common opinion is that working in a time-efficient manner will reduce the total cost of a project. Thorough planning of each operation, to anticipate uncertain events that can increase non-productive time, as well as having a contingency plan in case of bad weather, are just a few examples of many factors that can affect the project efficiency.

For instance, Aker BP has performed platform abandonment operations at Valhall DP in three large P&A campaigns, also known as batch operated P&A. This batch P&A campaign involved the abandonment of 30 well slots on the platform, by using a jack-up rig that could skid between the several well slots. The main advantage of batch P&A is to gain learning outcome, and the risk for uncertainties and surprises can be reduced for each subsequent plugged well slot. This method can largely lead to more effective P&A operations and a reduction in the time spent per well. The graph in figure 3.2 confirm that there has been a steady improvement progress throughout the batch campaign regarding the operational duration per well at Valhall DP. The estimated time and cost of the P&A campaigns at Valhall DP was originally 10 years and NOK 15.5 billion, but instead the work was complete in 4 years at a total cost of NOK 10.1 billion (Aker BP, 2021c). This further supports the statement "time is money". A constant focus on continuous improvement for P&A operations may therefore often lead to shorter operational duration and reduced costs.

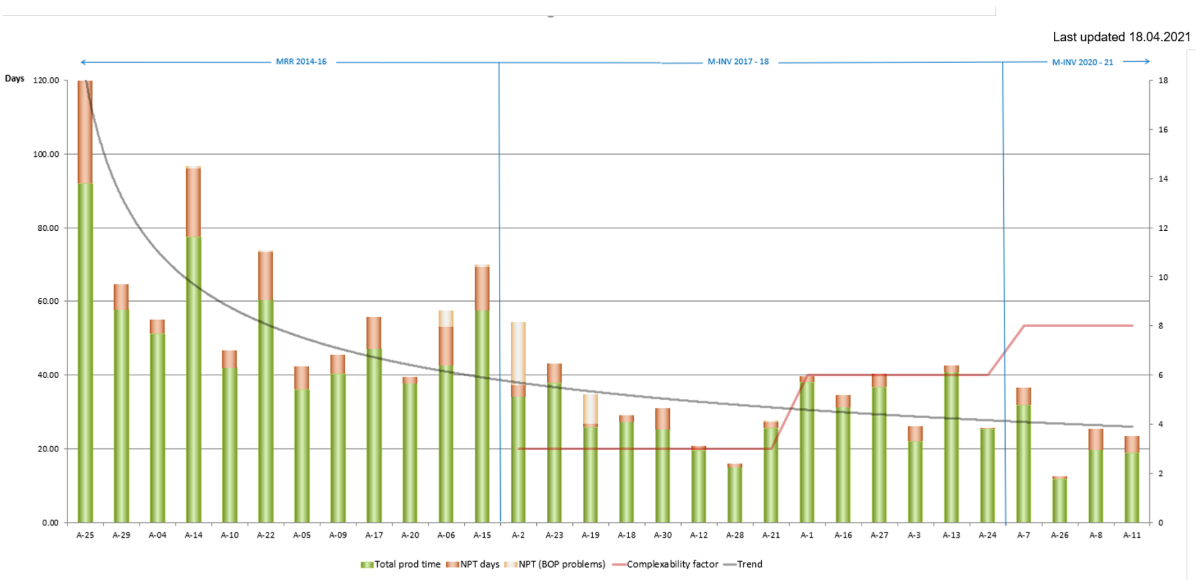


Figure 3.2: Improvement progress and performance of batch P&Aed wells at Valhall DP.

(Aker BP, 2021b)

3.3 Environmental Impact

An integral part of the Norwegian petroleum policy is to take care of the environment and climate. A large part of emissions to air comes from the use of gas turbines that generate electricity (Gavenas et al., 2015). A central source of emissions are the combustion of natural gas and diesel in turbines to produce electricity offshore.

Rig activity is normally very energy-consuming and driven by natural gas and diesel generators, and contributes to emissions such as carbon dioxide (CO_2) and nitrogen oxides (NO_x). A study done by the Norwegian Petroleum Directorate (2019) explains that approximately 14 million tonnes of CO_2 were emitted from the NCS in 2019, and 84.6% of released CO_2 was derived from gas turbines.

There is also a large difference in the amount of emissions coming from the different drilling rigs. For instance, the Maersk Invincible (MINV) jack-up rig has plugged 14 wells on the Valhall DP field. As probably for the first time ever, this drilling rig was powered fully from shore and reduced the annual local emissions by 15200 tonnes of CO_2 and 168 tonnes NO_x (Aker BP, 2018). This thoroughly emphasize a great demand and need for efficient technology that can reduce the environmental footprint, as it is proven to reduce environmental damage.

When using large drilling rigs for P&A operations, potential emissions must be considered, estimated, and calculated. If abandonment activities can be performed without costly and energy-consuming drilling rigs, this can entail significantly lower emissions (Forskningsrådet, 2018). On platforms, this means that the carbon footprint might be remarkably reduced if well abandonment operations can be carried out by using electrically powered well intervention equipment instead of drilling rigs.

4 Well Intervention Technology

Most of the operations described in the typical P&A procedure in section 2.4 are conventionally performed using a rig. In order to take a step towards a rigless P&A procedure, alternative abandonment methods and opportunities by using well intervention equipment will be investigated throughout this chapter.

Well intervention can be described as safely entering a well with well control for the purpose of doing several operations other than drilling (Kratz, 2012). During a well's life cycle from initial production to abandonment, intervention work includes operations related to maintenance, repairing and replacement. Well intervention operations were historically performed with drilling rigs, but with today's technology it is possible to re-entry wells with substitutes to the drilling well control systems and rigs for delivery of non-drilling services (Kratz, 2012). Well intervention equipment is normally diesel powered, but can also be fully electrically driven.

Table 4.1 briefly introduce the well intervention technology that will be deployed in this thesis case studies and time and cost analysis. The table illustrate typical P&A operations and the corresponding intervention technology that can be used instead of a rig. This chapter will mainly present a hydraulic jack and a wireline unit. The wireline intervention equipment, presented in section 4.1.1, has been described several times in the past, and this thesis therefore refer interested readers to the reference literature for a more detailed explanation. A hydraulic jack called WellRaizer is presented in section 4.2. This technology has never been presented in a scientific thesis before and will therefore be emphasized and thoroughly described in this section. A comprehensive explanation of how this technology can perform complex P&A operations will be provided.

Table 4.1: Presentation of typical P&A operations and the well intervention equipment involved in performing the operations.

		Activities	Technology	
			Hydraulic jack	Wireline
Phase 0	Step 1	Well head integrity check	X	X
	Step 2	Drift run	X	X
	Step 3	Caliper run	X	X
	Step 4	Integrity logging	X	X
	Step 5	Injection test/Killing well	X	
	Step 6	Cement squeeze perforations	X	
	Step 7	Install deep set plug	X	
	Step 8	Punch tubing	X	
	Step 9	Circulate heavy fluid (tubing + annulus)	X	
	Step 10	Cut tubing	X	
	Step 11	Displace annulus and tubing to brine or kill fluid	X	
	Step 12	Place tubing hanger plug in production and annulus bore	X	
Phase 1	Step 13	Remove XMT, install BOP	X	
	Step 14	Pull tubing	X	
	Step 15	Log cement	X	X
	Step 16	Clear annulus	X	
	Step 17	Install reservoir barrier	X	
Phase 2	Step 18	Install additional barriers above DPZs	X	
	Step 19	Install surface plug	X	
Phase 3	Step 20	Cut casing, wellhead and conductors	X	
	Step 21	Pull casing, wellhead and conductors	X	

4.1 Conventional Technology

4.1.1 Wireline

The purpose of a wireline unit is to perform well intervention activities and to check the wellbore conditions by lowering equipment down into the well. Examples of equipment that can be attached to the wireline is running tools, logging tools, pulling tools, cutters, and many more. Wireline technology are used for a wide variety of purposes such as logging, removal of scale, fishing operations, casing perforation and retrieval, tubing cutting, and installation of plugs. The preparations for abandonment, the "preparatory phase", normally starts with wireline diagnostics. Wireline investigation and logging can confirm that a wellbore is deformed or collapsed and indicate that a work string is unable to reach the reservoir or the required depths for placement of the final P&A barriers (Aker BP, 2017).

Wireline equipment can be divided into two different cable systems: slick line and braided line. The slickline is a smaller, non-electrical cable, while the braided line can provide electricity and has a higher tensile strength (Steen, 2013). Naturally, the braided line is thus more frequently used during heavier operations. For simplicity, wireline will refer to both slick line and braided line throughout this thesis.

Compared to other well intervention equipment, a wireline unit is rather small and easy to rig up. During wireline operations, pressure control devices are used in order to maintain well control and to prevent leakages and well blowouts. As illustrated in figure 4.1, the pressure control equipment is installed on top of the XMT, and mainly consists of a pressure control head that controls grease injection, lubricators that provides sealing and fluid control, a stuffing box and a BOP. The stuffing box forms the primary barrier and consist of rubber elements that ensures sealing around the wireline (Mikalsen, 2012). The BOP forms the secondary barrier, where a shear ram closing element closes across the wireline when the BOP is closed to provide wellbore sealing. With this setup, it is possible to maintain well control, as well as the two-barrier philosophy while lubricating in and running tool strings down live pressurized wells (Wittberg, 2017).

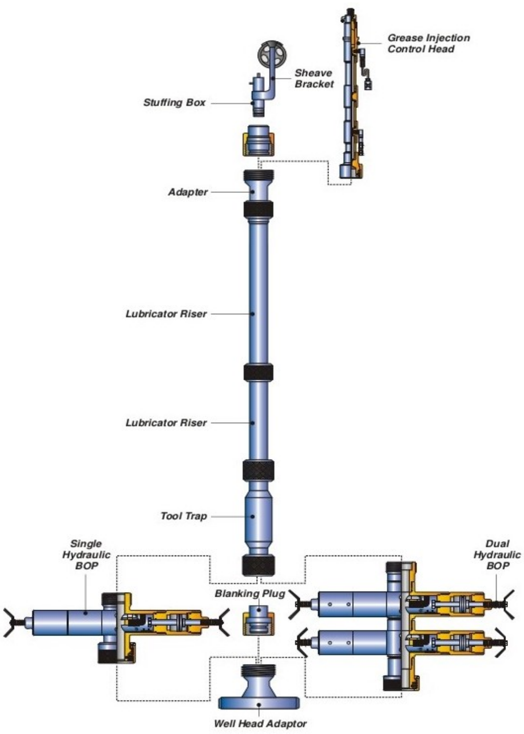


Figure 4.1: Illustration of wireline rig up.
(Parveen Industries Pvt. Ltd., nd)

It is possible to rig up a wireline unit almost anywhere, as it has a high flexibility. If wireline is used on a drilling rig, it is normally run through the rotary table of the drillfloor. For rigless operations, it is possible to run the wireline unit through a wireline mast or through a P&A working unit. For a P&A unit, it may not be necessary with all the available systems that can be found at the drilling rig (Khalifeh and Saasen, 2020). Section 4.2 will explain a hydraulic jacking system which in many ways serves as a drilling rig, where the wireline equipment can be run through the system.

4.2 Emerging Technologies

To pull tubing, casing, and conductor from a well can be extremely difficult to perform without a rig. As big surface forces are needed in such pulling operations, this has been an obstacle to a fully rigless P&A operation, and the "easiest" method has then been to use a drilling rig that ensure sufficient pulling force. In the following subsections, some emerging technologies will be thoroughly described, involving a hydraulic jack/recovery system called WellRaizer, that can retrieve tubing, casing, conductor, and wellhead without a rig. The recovery system can remind of existing modular rig units or P&A units, which is also an alternative to expensive drilling rigs. For instance, the abandonment project Jotun B, executed by Halliburton AS, utilized a cost-efficient modular P&A unit (Helgesen, 2018). Nevertheless, WellRaizer is revolutionary when it comes to abandoning platform wells, as it takes over heavy cut and pull operations that is usually rig dependent scope. The system is designed to provide and facilitate all P&A operations, and can perform pulling operations involved in all phases of the P&A sequence (Claxton Engineering, 2020a). This covers retrieval of production tubing and casing strings in phase 1 and phase 2 respectively, and conductor and wellhead removal in phase 3. Wireline can be run through the WellRaizer unit, and the recovery unit is also compliant with running cement through drill pipe for barrier installation.

4.2.1 WellRaizer

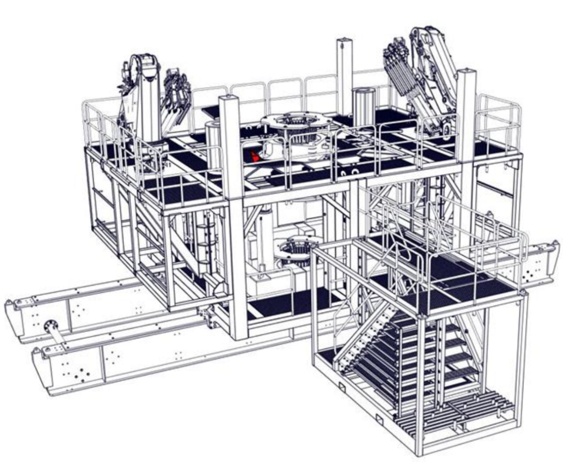
WellRaizer, the heavy duty rigless well recovery system owned by Claxton Engineering Services Ltd, is a hydraulic jacking system that provides the recovery offshore of oil and gas conductor pipes and casings of up to 36” in diameter (Claxton Engineering, 2017).

This technology has been utilized on the NCS to support rigless recovery of abandoned wells, and by using WellRaizer, a jack-up rig or a platform-based drilling derrick is no longer necessary (Claxton Engineering, 2017).

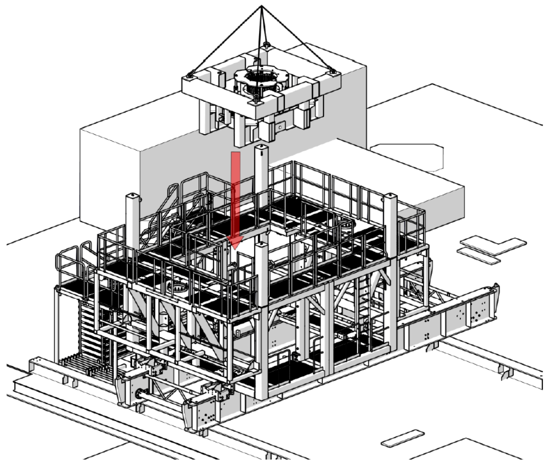
WellRaizer is compliant with NORSOK Z-015 and fulfill the design codes and safety standards for work on the NCS (Claxton Engineering, 2020d). The system is equipped with a safe working load of 300 metric tons and is designed in lightweight modular units minimizing rig-up time and complexity, with no component weighing over 10 metric tons (Claxton Engineering, 2020c). It is a flexible unit that is capable of skidding in both the X and Y axes, which makes it possible to skid between several well slots on platforms. This is especially advantageous in the execution of batch P&A campaigns. The design philosophy of the unit is to be compact and efficient during rig up and operation (Claxton Engineering, 2020a). The compactness is beneficial as the unit becomes more robust against weather, leading to reduced dependency on weather during operations. In addition, the hydraulic jack is smaller and more sustainable compared to a rig and can thus contribute to a reduced carbon footprint. For instance, the WellRaizer is driven by diesel generators, but emits only 20% as much emissions compared to a rig (M. Straume, personal communication, 2021).

The WellRaizer, illustrated in figure 4.2 mainly consists of the following equipment:

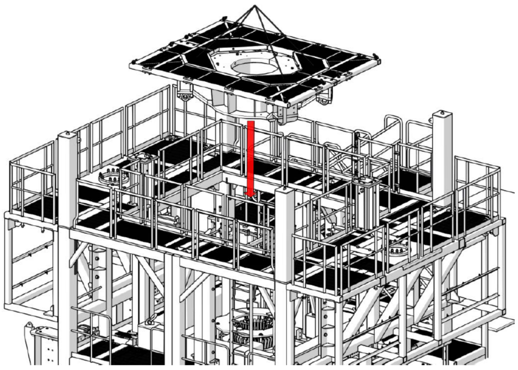
- A lower and upper cassette and a lower and upper pneumatic spider - the pneumatic spiders are designed with slips and utilized to grip the landing string.
- Landing string - provides a main role in the in-riser system and interface with the wellhead, ensuring safety during the jacking operation.
- Four hydraulic jacking cylinders - generates high lifting force and exert linear strength that produce the lifting or pulling action.



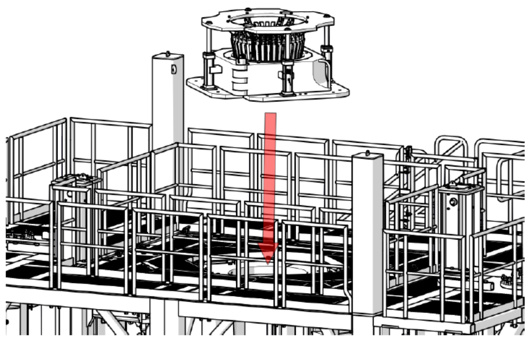
(a) Illustration of the WellRaizer unit.



(b) Placement of the lower pneumatic spider, on top of the lower cassette.



(c) Placement of the upper cassette.



(d) Placement of the upper pneumatic spider.

Figure 4.2: Illustration of WellRaizer rig up.
(Claxton Engineering, 2020a)

In addition, the recovery system consists of service tools such as a double drilling unit (DDU), a multi-string cut bandsaw severance, and a make-and-break system. The following provides a brief introduction to these tools as they form a central part of the conductor recovery system and procedure:

Double Drilling Unit:

When recovering multi-string casings, a drill and pin operation will be executed to ensure a safe simultaneous retrieval. This operation will be performed by a DDU unit mounted on the jacking frame on the hydraulic jack. After drilling the multiple casing strings, it is important to install a pin in the multi-string casing to mitigate the dropped object potential when handling the pipes on deck. Figure 4.3 illustrates a drilled and pinned multi-string casing.

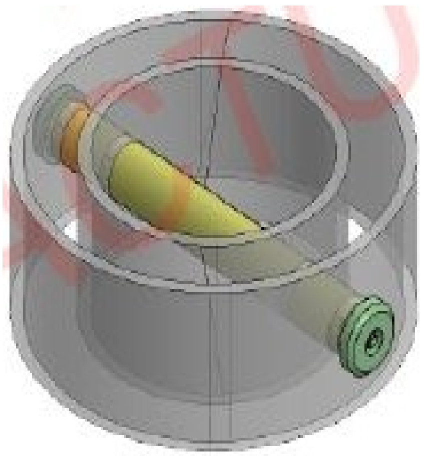


Figure 4.3: Drilled and pinned multi-string casing.
(Aker BP, 2021a)

Bandsaw severance:

The bandsaw can cut through steel conductors and casing with fully cemented and grouted annuli. The bandsaw is lifted and installed around the tubular using an open front and gate clamp system which is manually locked and clamped onto to the tubular. This operation commences once the combined strings have been drilled and pinned. Once the cut is complete, a "debris cap" is installed to the bottom of the cut joint prior to laying out to the pipe deck to ensure that no debris or dropped object hazards are encountered during the lay out operation (Claxton Engineering, 2020b). Figure 4.4 illustrates a bandsaw operation where the bandsaw cut between two installed casing pins.

Figure 4.4: Bandsaw cutting operation.
(Claxton Engineering, 2020a)

Make-and-break system for drill pipe:

A lightweight make-and-break system must be in place and skid in on the WellRaizer jacking frame before drill pipe joints are put in service. The purpose of this system is to ensure that all pipe connections are screwed together and tightened with torque.

4.2.1.1 Conductor and Wellhead Removal

Earlier, the conventional method to install the conductor casing was by conductor driving. This means that the conductor is hammered into the ground and cemented in place. At Valhall DP, the conductors are driven using the hammer technique to drive the pipe into the top-hole formations above SOI 1 (Aker BP, 2017). By using this installation method, the conductor can be considered as an independent part of the wellhead system, and will therefore be handled accordingly during the WellRaizer conductor removal in this thesis.

As explained in section 2.2, the wellhead is placed on top of the conductor. In order to retrieve the conductor, a pulling connection must be established between the conductor and the wellhead. To achieve this, a "drill and pin" operation must be performed below the wellhead to connect the conductor to the surface casing. Without pinning the conductor, the surface casing will be pulled instead during the WellRaizer conductor removal operation. The cement around the conductor creates friction between the conductor and the surface casing when the pin is installed, and this further contributes the conductor to be pulled upwards.

Prior to the start of the conductor and wellhead pulling operations, all SOIs must be isolated and the barrier envelope tested. An environmental plug must also be installed and tested for leakage. The first step in the drill and pin operation is to attach the drilling unit to the conductor. The purpose of the drilling unit is to drill through the conductor and surface casing until the drilling head penetrates the opposite side. A pulling pin is then inserted to the conductor before cleaning the area with vacuum pump. When the pinning work is complete, the conductor and wellhead removal can start as per Claxton's WellRaizer instructions.

The following procedure is provided by Claxton Engineering and guides us through the conductor and wellhead removal procedure using WellRaizer (C. Wetton, personal communication, 2021):

1. The pneumatic spiders are split, and the 30" landing string is run through the recovery tower to interface with the wellhead, as illustrated in figure 4.5 and figure 4.6. The landing string is designed with a pre-drilled hole, which will be of importance in step 3. Further, the upper spider is engaged onto the landing string and the overshot to the wellhead is fully engaged, as shown in figure 4.7.

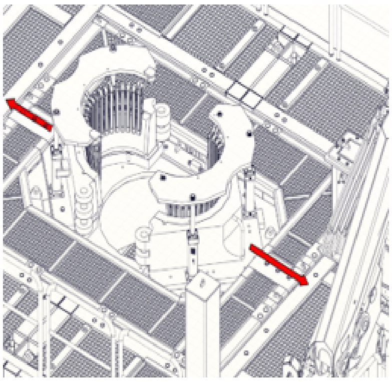


Figure 4.5: Splitted pneumatic spiders and prepared for the landing string.
(Claxton Engineering, 2020c)

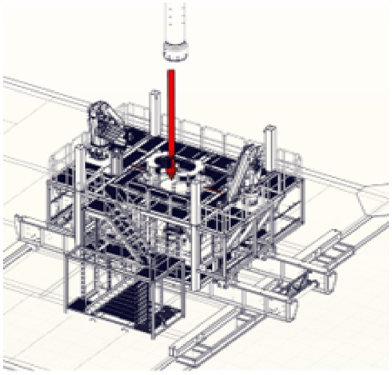


Figure 4.6: Landing string running through the recovery tower.
(Claxton Engineering, 2020c)

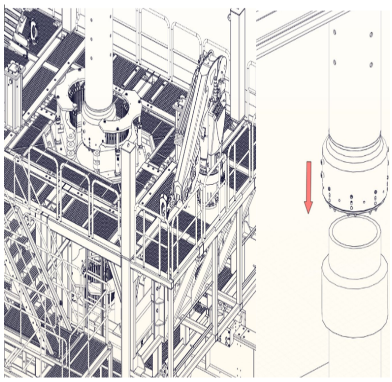


Figure 4.7: Landing string interface with the wellhead.
(Claxton Engineering, 2020c)

2. A drift run is performed to identify the wellbore condition and to determine the cutting depth, before starting the conductor cutting operations. When the conductor cutting is complete, a 4" load pin is attached to the 30" landing string in the pre-drilled holes. The platform main crane will be attached to the landing string to support any lateral movement, and therefore the load pin equipment is necessary.
3. The lower slips at the lower pneumatic spiders are released, and power is raised up the jacking cylinder to the required elevation. Further, the lower slips are engaged, and the conductor is set into slips, before releasing the upper slips. Then the jacking system is retracted. Figure 4.8 illustrates the concept of the WellRaizer jacking cylinders.

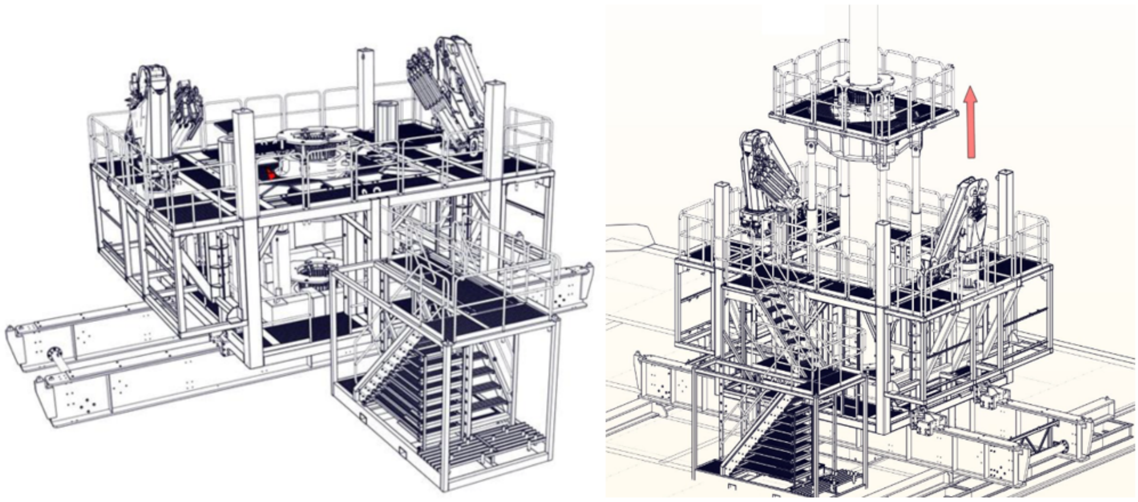


Figure 4.8: Elevation principle of the jacking cylinders.
(Claxton Engineering, 2020c)

4. Both pneumatic spiders must be engaged in preparation for surface pinning and severance operations. The DDU is positioned around the casing 1.5 meters below the wellhead and the multi-string casing is then drilled, as shown in figure 4.9. Once drilled, a 4" load pin is installed. Further, the DDU is re-positioned 0.75 meters above the previously drilled holes, before drilling through the dual strings. These holes are for the "sacrificial pin" that is used with debris caps in a later stage. The debris cap aims to protect the pipe. The bandsaw unit is then positioned around the casing and cut between the already installed pins, as illustrated in figure 4.10 and 4.11. When the casing is cut, a debris cap is installed to the first wellhead section in order to reduce the risk of dropped objects. The first cut casing section is then transferred away from the well center.

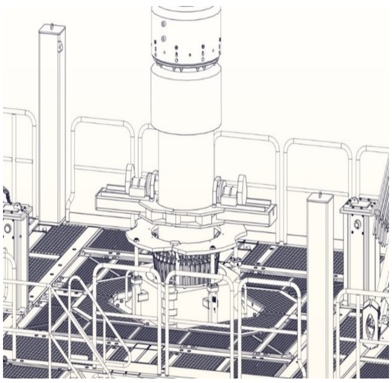


Figure 4.9: DDU operation.
(Claxton Engineering, 2020c)

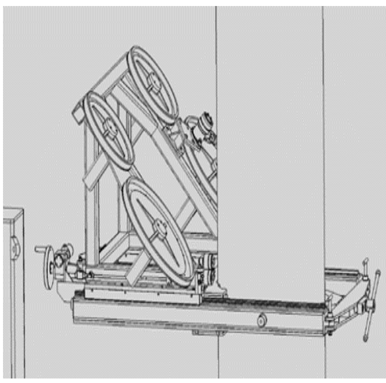


Figure 4.10: Bandsaw operation.
(Claxton Engineering, 2020c)

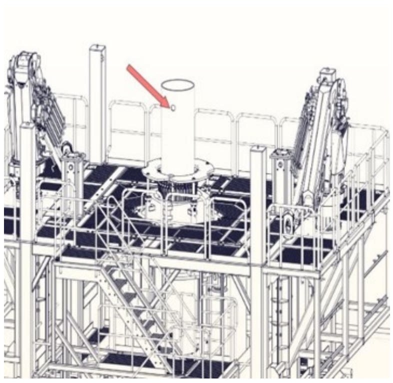


Figure 4.11: Cut casing and drilled 4" hole.
(Claxton Engineering, 2020c)

5. The sequence of the upper and lower slips operation to raise the conductor to the next required cut elevation is then repeated. The DDU is again positioned around the 30" conductor casing, this time 0.75 meters below the first casing coupling. Once drilled, a 4" load pin is installed. The DDU is then re-positioned 0.75 meters above the first casing coupling and drills through the dual strings, before installing a sacrificial pin for use with the debris cap. The bandsaw unit is then positioned around the casing and can start cut between the already installed pins. Once the cut is complete, the cut casing section can be removed. This procedure is repeated until the entire casing unit is retrieved.

4.2.1.2 Tubing Recovery

The production tubing is cut and pulled during the first phase of a P&A operation. This operation also requires high surface pulling forces in order to pull the entire tubing unit, and has therefore been a challenge regarding rigless abandonment methods. Using the WellRaizer recovery system is therefore suggested as a new method to pull out the tubing. Unlike the conductor and wellhead removal, there is no barrier envelope in place prior to this operation. The pulling structure is therefore slightly different as a BOP must be installed together with the WellRaizer unit in order to ensure well control during the tubing recovery.

Tubing recovery requires a low-weight jacking system and a platform crane, meanwhile the WellRaizer will provide a stable structure of the system. This low-weight equipment is easy to transport and install on platforms. During tubing recovery, the XMT will be removed and a high pressure (HP) riser will be run on top of the wellhead. Further, a BOP will be installed on top of the HP riser system. The HP riser acts as a conduit between the wellhead and the BOP and provides structural and global integrity (Oil States, 2019). In that way, well control is maintained during tubing recovery operations. Figure 4.12 illustrates the design of this suggested tubing recovery system.

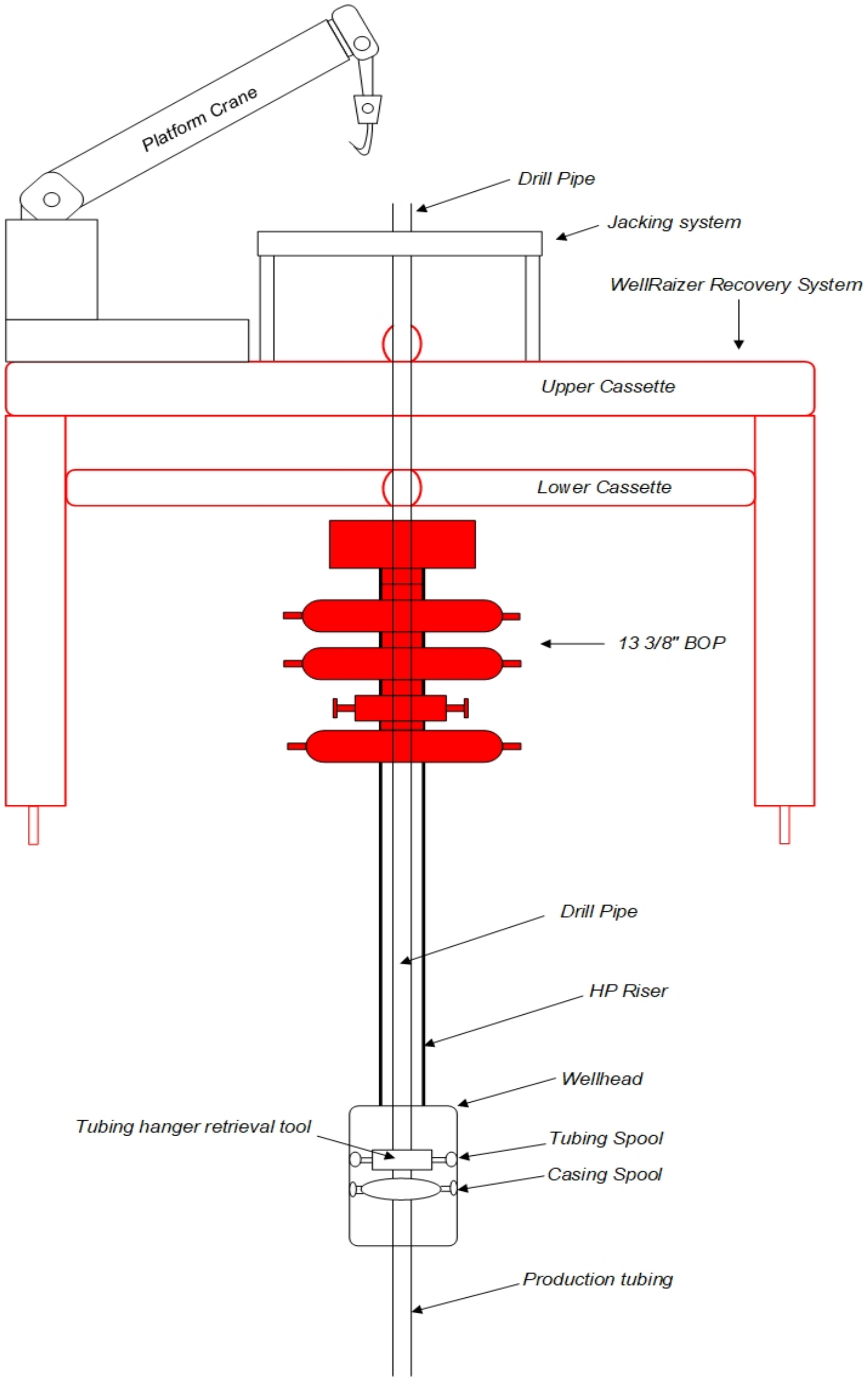


Figure 4.12: Suggested tubing recovery rig up.

As mentioned in section 2.2, the top of the production tubing is attached to the tubing spool on the wellhead. Drill pipe connections are properly broken in as per the make-and-break system through the WellRaizer recovery tower. A hanger retrieval tool will be run on drill pipe through the recovery system and attach to the tubing spool in the wellhead. This ensures an interaction between the cut tubing and the drill pipe. With such a recovery system in place, the jacking system and the platform crane can commence the pulling activity. As for the conductor and wellhead recovery, the tubing recovery is based on the same principles where the tubing is pulled and cut in several sections. It is not necessary to perform drill, pin and cut operations with DDU and bandsaw during tubing recovery as the tubing is a low-weight, single string. When the tubing is jacked up with the jacking system to the selected length, the make-and-break system then breaks the tubing in its connections.

4.2.1.3 Casing Recovery

Phase 2 of the abandonment procedure normally involves pulling operations of casings. Therefore, a method for casing recovery performed with the WellRaizer is suggested. Casing recovery requires bigger pulling forces than tubing recovery, as the casing strings have higher weight and are cemented in place. As for the tubing recovery, a BOP will be in installed together with the WellRaizer unit also during casing recovery.

The XMT will be removed and a HP riser will be run on top of the wellhead. Further, a BOP will be installed on top of the HP riser system. A recovery string, illustrated in figure 4.13, will then be run with a casing spear attached. This allows to run the recovery string to the area where the casing spool is placed to engage the recovery string to the casing. The tubing spool must be removed in order to access the casing spool, but this issue is already solved during tubing recovery. The casing spear ensures an interaction between the casing and the recovery string and makes it possible to pull the casing.

The WellRaizer casing recovery is based on the same procedure as presented in section 4.2.1.1. When the casing string is jacked up with the hydraulic jacking system to the selected length, it is broken in its connections. A 9 5/8" casing may just require a simple casing tong for the break-operation, while a 13 3/8" casing may require usage of the bandsaw unit as it is more massive.

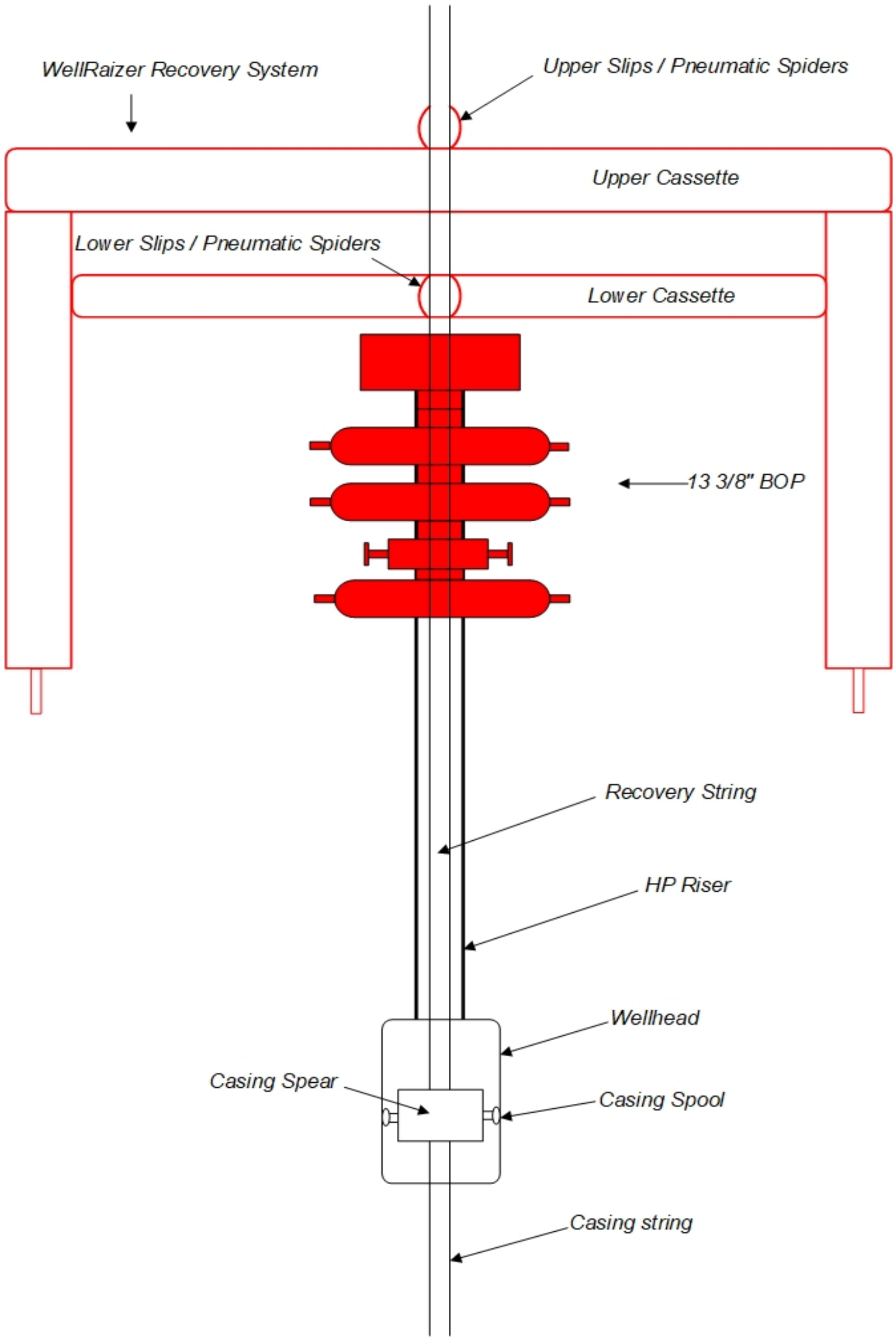


Figure 4.13: Suggested casing recovery rig up.

4.3 Limitations

It will not constitute a large part of this thesis, but it is however worth to mention some issues related to the rigless approach. Rigless P&A requires the same surface equipment that is positioned at drilling rigs. Platforms on the NCS have varied size and deck space, and the smallest platforms might face some issues related to the deck space on board for surface equipment. Limited deck space can therefore be an obstacle for rigless P&A as big infrastructure packages must be transported and placed on board the platform, containing for instance a hydraulic jacking unit, wireline, cementing systems, mud systems, pumping services and many more. To solve issues related to limited deck space, equipment must be rigged down and removed in order to obtain deck space, before new equipment can be rigged up. When using well intervention equipment on platforms, accommodation of P&A crew must be considered as well. Some platforms are unmanned, which means that the P&A crew must be transported to and from the platform installations. It is therefore crucial to consider and investigate the deck space and crew capacity when planning for rigless P&A operations on platforms. Limited deck space and unmanned platforms that require crew transfers will probably lead to a less effective operation.

5 Estimation Method and Data Collection

For the purpose of this thesis, Aker BP has provided with internal data for P&A operations. To understand the scope of rig-based and rigless P&A regarding time and cost, a simulation model is built based on this data. This chapter briefly present the simulation methodology used to estimate the abandonment duration and cost for this thesis' three case studies.

The modeling procedure will be explained, as well as the chosen uncertainties that will be included. Further, data collection reflecting parameters like cost and duration are given in section 5.2.

5.1 Methodology

In order to carry out time and cost estimations for the P&A operations, the probabilistic application iQx P1, produced by AGR Software, is used. P1 is a probabilistic simulation tool used to estimate operational time and cost where potential risks are considered and included. This tool applies Monte Carlo simulations where each time and cost output is the result of thousands of simulations. P1 runs 10000 iterations by default and provides an unbiased representative group of samples based on a large group of possibilities. By using this simulation method, it is possible to predict the chances of achieving objectives within any given time or cost output.

5.1.1 Monte Carlo Simulation

The Monte Carlo simulation technique is a numerical model that obtains statistics of output variables, given the statistics of the input variables (Al-aboodi, 2014). The input data might be defined as random or uncertain values. In each trial, the input values are sampled based on their distributions, while the output variables are calculated using the computational model (Cruse, 1997). The output is given as a range of numbers with associated probabilities of occurrence for all the possible outcomes within that range. The simulation model must be defined when applying P1 for Monte Carlo simulation. In this thesis' case studies, the duration will be forecasted and presented as output of the model. Further, proper data must be gathered and used as model inputs. Data gathering is the most time-consuming process of the simulation method, and should be thoroughly executed to provide the most accurate outcome possible.

The probability distribution shape that is used for the input data is the PERT distribution, which is based on the following input parameters: minimum (MIN), maximum (MAX) and most likely (ML) values. The distribution provides a smooth curve where the "ML" estimate is favored over the MIN and MAX estimate. By this, it is trusted that even if the ML value is not exactly accurate, there is an expectation that the resulting value will be close to that estimate (Structured Data LLC, nd). The simulation tool then generates the input by taking random sample according to the defined PERT distribution.

The output of the Monte Carlo simulation will be given as histograms and distribution curves, presented as a cumulative distribution function (CDF) and a probability density function (PDF) where percentiles will be obtained. Figure 5.1 provides an example of these two distributions. The X-axis in both functions will be representing the possible output values. The Y-axis in the PDF curve presents the occurrence probability corresponding to the value on the X-axis, while the Y-axis in the CDF curve presents the probability that the outcome takes a value that is equal or less than the corresponding value on the X-axis (Moeinikia et al., 2015).

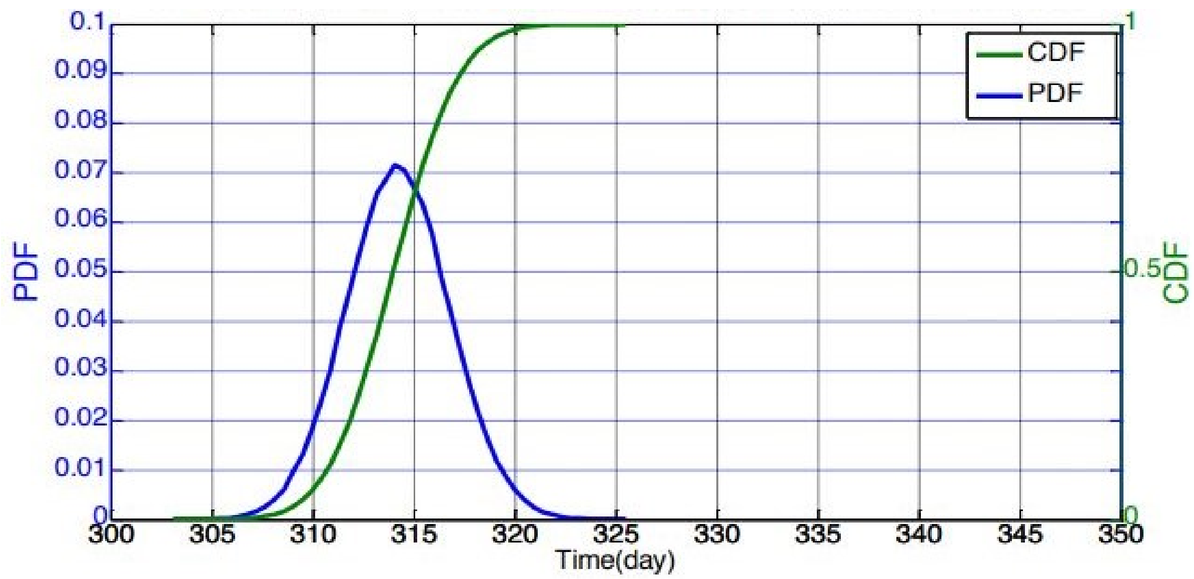


Figure 5.1: Example of a CDF and PDF distribution curve. (Moeinikia et al., 2014b)

Harsh weather can interrupt and force huge delays in operations, and thus have great impact on cost and duration of P&A activities. Also unexpected events often occur during operations and must be considered when planning for abandonment. Both the weather and unexpected events can lead to a less effective operation and can increase the total P&A time and costs, and is referred to as "waiting on weather" (WOW) and "non-productive time" (NPT). When estimating the total duration of P&A-operations, it is assumed that there will be some uncertainty and risk related to the MIN, MAX and ML values. Risk related to WOW and NPT is therefore incorporated as input parameters in the simulation model. A WOW factor of 6% and an NPT factor of 10% is used for the simulation. These risk factors are based on experiences from earlier operations, as well as recommendations and requirements from Aker BP.

5.2 Data Collection

5.2.1 Duration

When fitting Monte Carlo models for the simulation, data from a set of historical wells at Valhall DP that are similar to the well being P&Aed in this thesis' case studies, has been used. Inputs to the simulation regarding duration are collected based on historical data, expert judgement, and fundamental principles. Experiences and historical data for the 30 wells in the P&A Campaign at Valhall DP, reflecting operational duration, has thus been used for the time simulations. Figure 3.2 presented in section 3.2 provides a brief overview of the 30 wells and the duration spent on each well.

In parallel with writing this master thesis, Aker BP have conducted a conductor pulling campaign at Valhall DP, using the WellRaizer technology. Aker BP has thus provided with new data reflecting rig up time and time spent on each well from this campaign, which has been valuable information during the simulation of Case B and the Dream Well. In addition, forecasts concerning duration of WellRaizer operations, delivered by Claxton Engineering, has also been used to enhance the reliability of the simulation input.

For the purpose of input to the rigless P&A operations, Halliburton has provided with data from their Jotun B P&A project. This project used a rigless approach for abandonment, using equipment with low daily spread rate such as wireline and a modular P&A unit.

The project scope was split into several phases and has been used as inspiration for this thesis' rigless approach. Operational, historical data regarding time has thus been used as input for the operational rigless phases in the simulation model.

Both the selected MIN, MAX and ML values for duration have been experienced in the past, and standard deviations have also been taken into account during the selection. It is necessary to emphasize that historical data might not perfectly represent all possible outcomes as all wells are unique. By collecting as much data, experiences, and expert opinions as possible, the simulation becomes more reliable. Therefore, to increase the validity of the input, experts from companies such as Aker BP, Claxton Engineering, Halliburton, and Control Cutter, have been incorporated in this study.

5.2.2 Cost

Data regarding costs of P&A operations has been collected from Aker BP's database and expert engineers. The Strategy & Portfolio Management department develops Corporate Assumptions and has provided the thesis with data reflecting daily rates, service rates and upgrade rates for rigs, platforms, and technology equipment. All their forecasts are based on mean percentile values. As daily rig rates fluctuate and are affected by marked trends and demand, the forecasts are updated quarterly. As an example, Appendix A1 shows a three-year change of forecasted daily rate for the MINV jack-up rig and the forecasted daily rate for rigless platform P&A for the period 2017-2025. This graph emphasizes that there are uncertainties related to rig rates due to changing market trends, which is important information to consider when forecasting cost of rig-based operations.

A summary of the cost input used for estimating the total P&A cost for the case studies in this thesis is provided in Appendix A2. This thesis aims to use this data in the simulation model as Aker BP has a lean approach to corporate assumptions, where cost forecasts regarding the technology are regularly updated. To preserve confidential information in Aker BP, the cost input cannot be provided with all details.

6 Case Studies

In this chapter, three case studies that is incorporated into the Monte Carlo simulation model will be provided. As there exists thousands of wells, where all has their own unique design and face different challenges, it is impossible to cover all methods and technologies. Due to this, three different platform abandonment approaches will be discussed, and the cases will cover typical P&A operations and scenarios that often occur for different wells. A cost and duration forecast for the P&A operation will be performed for each case using the iQx P1 application. The cases will be compared with respect to the use of a rig-based approach, a rigless approach, and a combined approach.

Appendix A3 provides the fictitious platform well schematic that is planned to be abandoned in the three case studies. The schematic is developed based on work experience from Aker BP and has 4 potential SOIs. The 20" casing is cemented to surface, while the 9 5/8" casing and 13 3/8" casing is not cemented to top. The well is specified with the depths of the casing shoes. Information about depth is relevant when simulating duration, as different technological tools are run in and out to different depths of the well. Even though the well is identical for each abandonment case, the Monte Carlo simulation will provide different results for the duration and cost forecast. This can be explained as different technologies has been used, and the operational input has a unique probability distribution possibility for each case. One should remark that the operational procedure and input values are provided by experts and historical data, but to some extent may not cover all possible operations.

Case A and B will reflect today's scenarios, where there is typically poor annular bonding leading to several sources of inflow in the well. Therefore, the 13 3/8" casing is cut and pulled in order to log the 20" casing cement. It is further assumed that the 20" casing log shows good quality cement and no sustained casing pressure. The operations in phase 1 and 2 is rig-based and identical for case A and B.

The Dream Well case will reflect a "dream well", assuming access to historical data that confirm no gas migration from D-annulus and annular bonding with good quality. The 20" casing cement is therefore not logged. The purpose of the Dream Well case is to provide an innovative solution to a completely rigless abandonment operation. Compared with case A and B, some simplifications and assumptions for the dream well has been made to decrease the complexity of barrier installation. This can be explained by the fact that the thesis wants to focus on the cut-and-pull operations that are very different from the conventional method in all phases of case A and phase 1 and 2 of case B. The operations in phase 0 and 3 is identical for case B and the Dream Well.

- **Case A:** Rig-based scope in phase 0, 1, 2 and 3.
- **Case B:** Rig-based scope in phase 1 and 2, and rigless scope in phase 0 and 3.
- **Dream Well:** Rigless scope in phase 0, 1, 2 and 3.

6.1 Cost Analysis

To calculate the total cost of the P&A operation for each case study, spread rates and costs of the different technologies are multiplied with forecasted operational time. The spread rate reflects daily rental costs and daily service costs. The daily service cost includes planning, formation evaluation and logging, fluid and fluid services, waste and cuttings, cementing, pipe running and service, fuel, and logistic base labor and objects. Each operation also includes a tangible cost reflecting the cost of wellhead, XMT, casings, liners, casing and liner hangers, tubing, and completion accessories. Appendix A2 provides an overview of the cost of the technology used in the case studies.

6.2 Case A

Each phase of the P&A operation of the fictitious well is rig-based, where a jack-up rig is used during the entire abandonment operation. Table 6.1 presents the operational sequence for Case A, as well as a brief review of the Monte Carlo simulation input. The "phase name" represents the operational main step, while the "event name" represents sub-operations within the main step. Logging operations are performed with wireline that is rigged up on the platform rig. Input to these operations are based on calculations in relation to the depth of the well and the logging speed. PWC technology, explained in chapter 2.4, is applied to restore seal 3 due to poor annular cement behind the 20" casing.

The duration of conductor cutting, drilling, and pinning, which has been explained in previous sections, will be the same regardless of whether the operation is rigless or rig-based, if the same conventional technology is used. Factors that can provide a difference in duration and cost are therefore the technology that is used for these particular operations, as explained in section 2.5. Conventional cut and pin operations is calculated approximately 2 hours each. More effective technology provided by for instance ControlCutter AS provides 4 minutes and 3 minutes for conductor cutting and pinning, respectively (P. Birkeland, personal communication, 2021). In order to provide a realistic example of a rig-based phase 3 approach, duration reflecting the best and most effective conductor cutting and pinning technology that exists in today's market has been used for case A. This can provide an interesting perspective when comparing the several cases later in this thesis. Efficient and new technology will reduce the days of operation and thus reduce the rig-time. For case A, it is interesting to investigate if the difference in cost and duration is significant compared to case B, even when technology that reduces the rig-time considerably has been used in case A.

Table 6.1: Operational sequence and input to the Monte Carlo simulation model for case A.

	Phase Name	Event Name	Variable unit	Variable			
				Distribution Type	A	B	C
PHASE 0	**Prepare well for P&A and cut tubing**						
		Drift run and caliper run	Trip(Mt/Hr)	PERT (Min, ML, Max)	200,00	400,00	600,00
		Integrity logging	Trip(Mt/Hr)	PERT (Min, ML, Max)	200,00	400,00	540,00
		Kill well, bullhead cement	Hours	PERT (Min, ML, Max)	6,00	9,00	12,00
		Install deep set bridge plug and test plug	Hours	PERT (Min, ML, Max)	8,00	14,00	20,00
		Punch tubing above production packer	Hours	PERT (Min, ML, Max)	6,00	7,00	8,00
		Circulate heavy fluid (tubing+annulus)	Hours	PERT (Min, ML, Max)	1,00	2,25	3,50
		Cut tubing above the production packer	Hours	PERT (Min, ML, Max)	5,00	6,00	7,00
		Displace annulus and tubing to kill fluid/brine	Hours	PERT (Min, ML, Max)	1,00	3,50	6,00
		Install downhole safety valve protection sleeve	Hours	PERT (Min, ML, Max)	6,00	10,00	12,00
		Place tubing hanger plug in production and annulus bore	Hours	PERT (Min, ML, Max)	15,00	17,00	20,00
PHASE 1	**Pull vertical XMT and N/U BOP**						
		Pull vertical XMT to surface	Hours	PERT (Min, ML, Max)	12,00	15,50	19,00
		Install BOP	Hours	PERT (Min, ML, Max)	11,51	17,60	23,69
	Recover Production Tubing						
		Pull tubing hanger and tubing	Hours	PERT (Min, ML, Max)	24,12	31,15	38,18
	Cleanout and log 9 5/8" casing						
		Clean 9 5/8" casing	Hours	PERT (Min, ML, Max)	15,85	32,50	49,15
		Log 9 5/8" casing	Trip(Mt/Hr)	PERT (Min, ML, Max)	200,00	400,00	540,00
	Set reservoir plug inside 9 5/8" casing (seal 4)						
		Set 9 5/8" bridge plug	Hours	PERT (Min, ML, Max)	7,73	13,50	19,27
		Set primary cement plug inside 9 5/8" casing	Hours	PERT (Min, ML, Max)	15,51	17,92	20,32
		Wait on cement and test plug	Hours	PERT (Min, ML, Max)	3,00	7,75	14,00
		Set secondary plug inside 9 5/8" casing	Hours	PERT (Min, ML, Max)	15,51	17,92	20,32
		Wait on cement and test plug	Hours	PERT (Min, ML, Max)	3,00	7,75	14,00
PHASE 2	**Restore seal 3**						
		PWC - Primary plug	Hours	PERT (Min, ML, Max)	36,50	49,00	73,00
		Wait on cement and test cement plug	Hours	PERT (Min, ML, Max)	3,00	7,75	14,00
		PWC - Secondary plug	Hours	PERT (Min, ML, Max)	36,50	49,00	73,00
		Wait on cement and test plug	Hours	PERT (Min, ML, Max)	3,00	7,75	14,00
	Cut and pull 9 5/8" casing & cleanout and log 13 3/8" casing						
		Cut and pull 9 5/8" casing	Hours	PERT (Min, ML, Max)	16,75	29,25	41,75
		Cleanout 13 3/8" casing	Hours	PERT (Min, ML, Max)	4,87	10,90	17,00
		Log 13 3/8" casing	Trip(Mt/Hr)	PERT (Min, ML, Max)	200,00	400,00	540,00
	Restore seal 2						
		Install 13 3/8" bridge plug	Hours	PERT (Min, ML, Max)	6,73	11,65	16,57
		Set primary cement plug inside 13 3/8" casing	Hours	PERT (Min, ML, Max)	15,51	17,92	20,32
		Wait on cement and test plug	Hours	PERT (Min, ML, Max)	3,00	7,75	14,00
		Set secondary cement plug inside 13 3/8" casing	Hours	PERT (Min, ML, Max)	15,51	17,92	20,32
		Wait on cement and test plug	Hours	PERT (Min, ML, Max)	3,00	7,75	14,00
	Cut and pull 13 3/8" casing						
		Cut and pull 13 3/8" casing	Hours	PERT (Min, ML, Max)	18,18	40,58	62,99
	Cleanout and log 20" casing						
		Cleanout 20" casing	Hours	PERT (Min, ML, Max)	5,63	10,88	16,20
		Log 20" casing	Trip(Mt/Hr)	PERT (Min, ML, Max)	200,00	400,00	540,00
	Restore seal 1 - Install surface barrier						
		Set 20" EZSV	Hours	PERT (Min, ML, Max)	4,70	6,25	14,28
		Install environmental cement plug	Hours	PERT (Min, ML, Max)	5,00	6,85	8,70
		Wait on cement and test plug	Hours	PERT (Min, ML, Max)	3,00	7,75	14,00
	N/D BOP						
		N/D BOP	Hours	PERT (Min, ML, Max)	1,00	2,00	3,00
PHASE 3	**Cut casing and conductor**						
		Drill and pin conductor and casings	Hours	PERT (Min, ML, Max)	0,06	0,06	0,07
		Conduct cut	Hours	PERT (Min, ML, Max)	0,05	0,05	0,06
	Retrieve wellhead, surface casing and conductor						
		Retrieve Wellhead and conductor casing	Hours	PERT (Min, ML, Max)	25,00	30,00	35,00

For the purpose of cost estimation for case A, the following technology expenses are included: daily rig rate, daily rig service rate, daily wireline rate, BOP rate, cutting equipment rates and tangible costs.

6.3 Case B

For this case, the P&A procedure provides a combination of rig-based and rigless operations. The rig scope has been remarkably reduced compared to case A, as phase 0 and phase 3 is performed completely rigless by using well intervention equipment. The WellRaizer unit is rigged up on the platform in phase 3. Phase 1 and 2 for this case is rig-based and identical case A.

Table 6.2 presents the operational sequence for case B, and the associated MIN, ML and MAX duration input to the Monte Carlo simulation model. This study provides a very similar abandonment approach as Aker BP's P&A campaign at Valhall DP. Spring 2021, Aker BP performed phase 3 with the WellRaizer technology, and this has been the source of inspiration when making this case study. Operations involving cutting, pulling, drilling, and pinning using the WellRaizer technology are based on real experiences and data. Rigging up the WellRaizer unit is expected to take approximately a week and explains why this event has a different distribution type than the other events. Operations involving logging and barrier installation are based on experiences and data from the rigless Jotun B project, delivered by Halliburton AS.

Daily rental of jack-up rig, WellRaizer, wireline, drill pipe, cutting equipment, rigless equipment package, as well as the tangible costs are included in the cost estimate.

Table 6.2: Operational sequence and input to the Monte Carlo simulation model for case B.

	Phase Name	Event Name	Variable unit	Variable			
				Distribution Type	A	B	C
PHASE 0	**Prepare well for P&A and cut tubing**						
		Drift run and caliper run	Trip(Mt/Hr)	PERT (Min, ML, Max)	200,00	400,00	600,00
		Integrity logging	Trip(Mt/Hr)	PERT (Min, ML, Max)	200,00	400,00	540,00
		Kill well, bullhead cement	Hours	PERT (Min, ML, Max)	6,00	9,00	12,00
		Install deep set bridge plug and test plug	Hours	PERT (Min, ML, Max)	6,50	9,00	11,50
		Punch tubing above production packer	Hours	PERT (Min, ML, Max)	6,00	7,00	8,00
		Circulate heavy fluid (tubing+annulus)	Hours	PERT (Min, ML, Max)	1,00	2,25	3,50
		Cut tubing above the production packer	Hours	PERT (Min, ML, Max)	12,00	14,00	30,00
		Displace annulus and tubing to kill fluid/brine	Hours	PERT (Min, ML, Max)	3,00	4,50	7,90
		Install downhole safety valve protection sleeve	Hours	PERT (Min, ML, Max)	6,00	10,00	12,00
		Place tubing hanger plug in production and annulus bore	Hours	PERT (Min, ML, Max)	12,70	16,50	20,00
PHASE 1	**Pull vertical XMT and N/U BOP**						
		Pull vertical XMT to surface	Hours	PERT (Min, ML, Max)	7,00	12,00	17,00
		Install BOP	Hours	PERT (Min, ML, Max)	11,51	17,60	23,69
	Recover Production Tubing						
		Pull tubing hanger and tubing	Hours	PERT (Min, ML, Max)	24,12	31,15	38,18
	Cleanout and log 9 5/8" casing						
		Clean 9 5/8" casing	Hours	PERT (Min, ML, Max)	15,85	32,50	49,15
		Log 9 5/8" casing	Trip(Mt/Hr)	PERT (Min, ML, Max)	200,00	400,00	540,00
	Set reservoir plug inside 9 5/8" casing (seal 4)						
		Set 9 5/8" bridge plug	Hours	PERT (Min, ML, Max)	7,73	13,50	19,27
		Set primary cement plug inside 9 5/8" casing	Hours	PERT (Min, ML, Max)	15,51	17,92	20,32
		Wait on cement and test plug	Hours	PERT (Min, ML, Max)	3,00	7,75	14,00
		Set secondary plug inside 9 5/8" casing	Hours	PERT (Min, ML, Max)	15,51	17,92	20,32
		Wait on cement and test plug	Hours	PERT (Min, ML, Max)	3,00	7,75	14,00
PHASE 2	**Restore seal 3**						
		PWC - Primary plug	Hours	PERT (Min, ML, Max)	36,50	49,00	73,00
		Wait on cement and test cement plug	Hours	PERT (Min, ML, Max)	3,00	7,50	14,00
		PWC - Secondary plug	Hours	PERT (Min, ML, Max)	36,50	49,00	73,00
		Wait on cement and test plug	Hours	PERT (Min, ML, Max)	3,00	7,75	14,00
	Cut and pull 9 5/8" casing & cleanout and log 13 3/8" casing						
		Cut and pull 9 5/8" casing	Hours	PERT (Min, ML, Max)	16,75	29,25	41,75
		Cleanout 13 3/8" casing	Hours	PERT (Min, ML, Max)	4,87	10,90	17,00
		Log 13 3/8" casing	Trip(Mt/Hr)	PERT (Min, ML, Max)	200,00	400,00	540,00
	Restore seal 2						
		Install 13 3/8" bridge plug	Hours	PERT (Min, ML, Max)	6,73	11,65	16,57
		Set primary cement plug inside 13 3/8" casing	Hours	PERT (Min, ML, Max)	15,51	17,92	20,32
		Wait on cement and test plug	Hours	PERT (Min, ML, Max)	3,00	7,75	14,00
		Set secondary cement plug inside 13 3/8" casing	Hours	PERT (Min, ML, Max)	15,51	17,92	20,32
		Wait on cement and test plug	Hours	PERT (Min, ML, Max)	3,00	7,75	14,00
	Cut and pull 13 3/8" casing						
		Cut and pull 13 3/8" casing	Hours	PERT (Min, ML, Max)	18,18	40,58	62,99
	Cleanout and log 20" casing						
		Cleanout 20" casing	Hours	PERT (Min, ML, Max)	5,63	10,88	16,20
		Log 20" casing	Trip(Mt/Hr)	PERT (Min, ML, Max)	200,00	400,00	540,00
	Restore seal 1 - Install surface barrier						
		Set 20" EZSV	Hours	PERT (Min, ML, Max)	4,70	6,25	14,28
		Install environmental cement plug	Hours	PERT (Min, ML, Max)	5,00	6,85	8,70
		Wait on cement and test plug	Hours	PERT (Min, ML, Max)	3,00	7,75	14,00
	N/D BOP						
PHASE 3		N/D BOP	Hours	PERT (Min, ML, Max)	1,00	2,00	3,00
	Rig up Claxton WellRaizer						
		Rig up Claxton WellRaizer	Hours	Spike (ML)		170,00	
	Cut casing and conductor						
		Drill and pin conductor	Hours	PERT (Min, ML, Max)	0,50	0,66	1,00
		Cut casings and conductor	Hours	PERT (Min, ML, Max)	14,40	17,50	20,50
	Retrieve wellhead, surface casing and conductor						
		Pull up and run landing string	Hours	PERT (Min, ML, Max)	10,00	12,00	13,00
		Engage to wellhead and surface	Hours	PERT (Min, ML, Max)	10,00	12,00	12,00
		Pull wellhead to surface	Hours	PERT (Min, ML, Max)	3,50	4,00	5,00
		Bore and pin below overshot	Hours	PERT (Min, ML, Max)	1,50	2,00	3,00
		Cut, pin and lay down sections	Hours	PERT (Min, ML, Max)	23,50	24,00	25,00
		Secure deck openings	Hours	PERT (Min, ML, Max)	1,50	2,00	3,00

6.4 Dream Well

For the dream well, it is assumed that the 20" casing cement was logged after cementing and that the historical logging data show good quality cement. Even though there is no sustained casing pressure in D-annulus, it is decided to cut and pull the 13 3/8" casing and install an internal 20" cross-sectional surface barrier. This further emphasize the opportunities and solutions with the rigless technology, even though a 13 3/8" cross-sectional surface barrier would be sufficient in this case. This also constitutes a fully comparative relationship between the Dream Well and case A and B regarding operations, and thus time and cost.

The rigless recovery system, WellRaizer, is planned to have interface with the platform system in addition to other well intervention equipment to complete the entire P&A operation of the Dream Well-case. The WellRaizer unit is rigged up in phase 1 of the abandonment operation. Equipment such as wireline, drill pipe, recovery strings and several service and operating tools are run through the WellRaizer. The recovery system has many of the same features as a drilling rig, especially when it comes to pulling and surface forces. As drill pipe is already used during the tubing recovery, it will also be used through the WellRaizer to pump and establish permanent cement barriers above the required SOIs.

Wireline is run in hole to perform well diagnostics and to cut the production tubing. The tubing is then recovered as per WellRaizer tubing recovery procedure explained in previous sections. All logging operations are performed with wireline. For the fictitious well, it is assumed that the 9 5/8" annular cement log shows good quality, and two cross-sectional internal cement plugs are set with drill pipe above SOI 4 and SOI 3. The 9 5/8" casing is cut and pulled with the WellRaizer, as per the casing recovery procedure. It is assumed that the 13 3/8" logging results shows good annular cement quality and no source of inflow. Two cross-sectional internal cement plugs are then set with drill pipe above SOI 2. The 13 3/8" casing is then pulled with the WellRaizer. As this case describes the abandonment of a "dream well", it is reasonable to assume that D-annulus has sufficient bonding and that the well is killed when seal 2 is restored. The 13 3/8" BOP can thus be safely removed from the well, and the 13 3/8" casing can be cut and pulled with the WellRaizer unit. A 20" internal cement plug is set with drill pipe and verified as surface plug. Table 6.3 presents the operational sequence for the Dream Well, and the associated MIN, ML and MAX duration input to the Monte Carlo simulation model.

A rigless P&A operation relies on infrastructure which normally exist on drilling rigs, as explained in section 4.3. Infrastructure packages including cementing systems, mud systems, pumping services such as tanks, silos, pumps, shakers, and blenders must be transported on board the platform. The cost of such an equipment package depends on the infrastructure available on the platform. Otherwise, tangible costs and daily rental of WellRaizer, wireline, drill pipe, BOP and HP riser, pipe handling equipment, cutting equipment and a small jacking system are included in the cost estimate.

Table 6.3: Operational sequence and input to the Monte Carlo simulation model for the Dream Well.

	Phase Name	Event Name	Variable unit	Variable			
				Distribution Type	A	B	C
PHASE 0	**Prepare well for P&A and cut tubing**						
		Drift run and caliper run	Trip(Mt/Hr)	PERT (Min, ML, Max)	200,00	400,00	600,00
		Integrity logging	Trip(Mt/Hr)	PERT (Min, ML, Max)	200,00	400,00	540,00
		Kill well, bullhead cement	Hours	PERT (Min, ML, Max)	6,00	9,00	12,00
		Install deep set bridge plug and test plug	Hours	PERT (Min, ML, Max)	6,50	9,00	11,50
		Punch tubing above production packer	Hours	PERT (Min, ML, Max)	6,00	7,00	8,00
		Circulate heavy fluid (tubing+annulus)	Hours	PERT (Min, ML, Max)	1,00	2,25	3,50
		Cut tubing above the production packer	Hours	PERT (Min, ML, Max)	12,00	14,00	30,00
		Displace annulus and tubing to kill fluid/brine	Hours	PERT (Min, ML, Max)	3,00	4,50	7,90
		Install downhole safety valve protection sleeve	Hours	PERT (Min, ML, Max)	6,00	10,00	12,00
		Place tubing hanger plug in production and annulus bore	Hours	PERT (Min, ML, Max)	12,70	16,50	20,00
PHASE 1	**Rig up Claxton WellRaizer**						
		Rig up Claxton WellRaizer	Hours	Spike (ML)		170,00	
	Pull vertical XMT and N/U BOP						
		Pull vertical XMT to surface	Hours	PERT (Min, ML, Max)	12,00	15,50	19,00
		Install BOP	Hours	PERT (Min, ML, Max)	11,51	17,60	23,69
	Recover Production Tubing						
		Pull up and run landing string	Hours	PERT (Min, ML, Max)	10,00	12,00	13,00
		Engage to wellhead	Hours	PERT (Min, ML, Max)	10,00	12,00	13,00
		RIH with tubing hanger retrieval tool & engage tubing hanger	Hours	PERT (Min, ML, Max)	1,50	1,75	2,00
		Pull tubing hanger and tubing	Hours	PERT (Min, ML, Max)	49,50	66,00	132,00
	Cleanout and log 9 5/8" casing						
		Clean 9 5/8" casing	Hours	PERT (Min, ML, Max)	47,40	61,00	64,70
		Log 9 5/8" casing	Trip(Mt/Hr)	PERT (Min, ML, Max)	170,00	180,00	190,00
	Set reservoir plug inside 9 5/8" casing (seal 4)						
		Install 9 5/8" Bridge plug	Hours	PERT (Min, ML, Max)	20,00	25,00	30,00
		Set primary reservoir plug inside 9 5/8" casing	Hours	PERT (Min, ML, Max)	22,00	28,00	35,00
		Wait on cement and test plug	Hours	PERT (Min, ML, Max)	12,00	14,00	16,00
		Set secondary reservoir plug inside 9 5/8" casing	Hours	PERT (Min, ML, Max)	22,00	28,00	35,00
		Wait on cement and test plug	Hours	PERT (Min, ML, Max)	12,00	14,00	16,00
PHASE 2	**Restore seal 3**						
		Install 9 5/8" Bridge plug	Hours	PERT (Min, ML, Max)	15,00	17,00	20,00
		Primary internal cement plug	Hours	PERT (Min, ML, Max)	22,00	28,00	35,00
		Wait on cement and test cement plug	Hours	PERT (Min, ML, Max)	12,00	14,00	16,00
		Secondary internal cement plug	Hours	PERT (Min, ML, Max)	42,50	46,00	49,50
		Wait on cement and test plug	Hours	PERT (Min, ML, Max)	12,00	14,00	16,00
	Cut and pull 9 5/8" casing & cleanout and log 13 3/8" casing						
		Cut 9 5/8" casing	Hours	PERT (Min, ML, Max)	9,00	12,00	15,00
		RIH with casing hanger retrieval tool and engage casing hanger	Hours	PERT (Min, ML, Max)	2,65	3,25	3,80
		Pull 9 5/8" casing	Hours	PERT (Min, ML, Max)	52,00	79,00	105,00
		Cleanout 13 3/8" casing	Hours	PERT (Min, ML, Max)	9,00	9,70	10,00
		Log 13 3/8" casing	Trip(Mt/Hr)	PERT (Min, ML, Max)	170,00	180,00	190,00
	Restore seal 2						
		Install 13 3/8" Bridge plug	Hours	PERT (Min, ML, Max)	6,00	8,00	10,00
		Primary internal cement plug	Hours	PERT (Min, ML, Max)	22,00	28,00	35,00
		Wait on cement and test cement plug	Hours	PERT (Min, ML, Max)	12,00	14,00	16,00
		Secondary internal cement plug	Hours	PERT (Min, ML, Max)	22,00	28,00	35,00
		Wait on cement and test cement plug	Hours	PERT (Min, ML, Max)	12,00	14,00	16,00
	N/D BOP						
		N/D BOP	Hours	PERT (Min, ML, Max)	1,00	2,00	3,00
	Cut and pull 13 3/8" Casing						
		Cut 13 3/8" casing	Hours	PERT (Min, ML, Max)	9,00	12,00	15,00
		Pull 13 3/8" casing using WellRaizer	Hours	PERT (Min, ML, Max)	13,00	18,00	26,00
	Restore seal 1 - surface barrier						
		Install 20" bridge plug	Hours	PERT (Min, ML, Max)	5,40	5,80	7,20
		Mix and pump cement	Hours	PERT (Min, ML, Max)	4,15	4,75	5,35
		Install environmental cement plug	Hours	PERT (Min, ML, Max)	1,10	1,75	2,40
		Wait on cement	Hours	PERT (Min, ML, Max)	2,00	6,00	12,00
		Verify surface plug	Hours	PERT (Min, ML, Max)	1,50	3,30	5,00
PHASE 3	**Cut casing and conductor**						
		Drill and pin conductor	Hours	PERT (Min, ML, Max)	0,50	0,66	1,00
		Cut casings and conductor	Hours	PERT (Min, ML, Max)	14,40	17,50	20,50
	Retrieve wellhead, surface casing and conductor						
		Pull up and run landing string	Hours	PERT (Min, ML, Max)	10,00	12,00	13,00
		Engage to wellhead and conductor	Hours	PERT (Min, ML, Max)	10,00	12,00	12,00
		Pull wellhead to surface	Hours	PERT (Min, ML, Max)	3,50	4,00	5,00
		Bore and pin below overshot	Hours	PERT (Min, ML, Max)	1,50	2,00	3,00
		Cut, pin and lay down sections	Hours	PERT (Min, ML, Max)	23,50	24,00	25,00
		Secure deck openings	Hours	PERT (Min, ML, Max)	1,50	2,00	3,00

7 Estimation Results

In this chapter, the simulation results reflecting the operational duration will be presented in graphs, histograms, and tables for each case study. Further, the cost estimates will be presented, as well as a comparison of time and cost between the case studies.

7.1 Case A

A report of the time CDF plot is presented in figure 7.1 and shows the probability of being less than or equal the duration on the X-axis. For instance, the P90 value is 32.17 days, which means that there is a 90% probability that the well can be P&Aed within 32.17 days or less. At the same time, it also means that there is a 10% probability that the well can be P&Aed within 32.17 days or more. The P10 value shows 23.99 days, which provides a 10% probability to abandon the well within 23.99 days or less, and a 90% probability to abandon the well within 23.99 days or more. In addition, Appendix A4 provides the simulation results for the mean percentile, P10, P50 and P90, as well as a detailed operational breakdown with all phases and events.

The mean value of the time CDF explains that the average of the simulations that are run with all percentiles in the model involved, will be equal or less than 28.05 days. The time PDF, shown in figure 7.2, illustrate that the time ranges with the highest occurrence probability and likelihood is approximately 27 to 28 days or 28 to 29 days. This means that the probability that a random variable in the simulation model will fall within one of these two time intervals is 12% each.

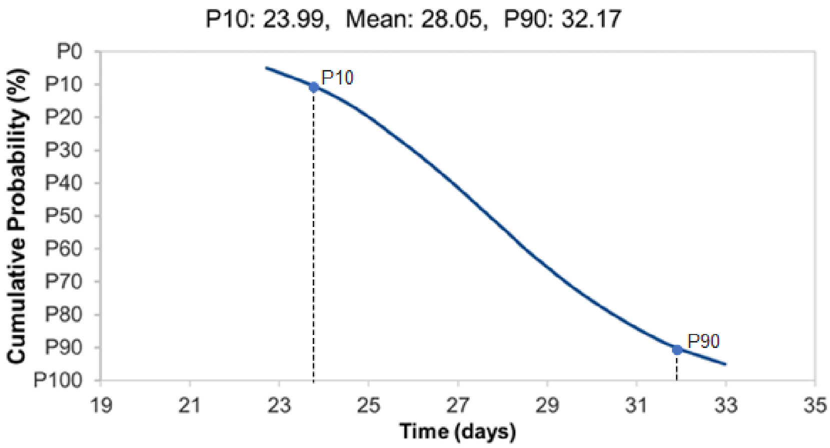


Figure 7.1: Time Cumulative Distribution Function for case A.

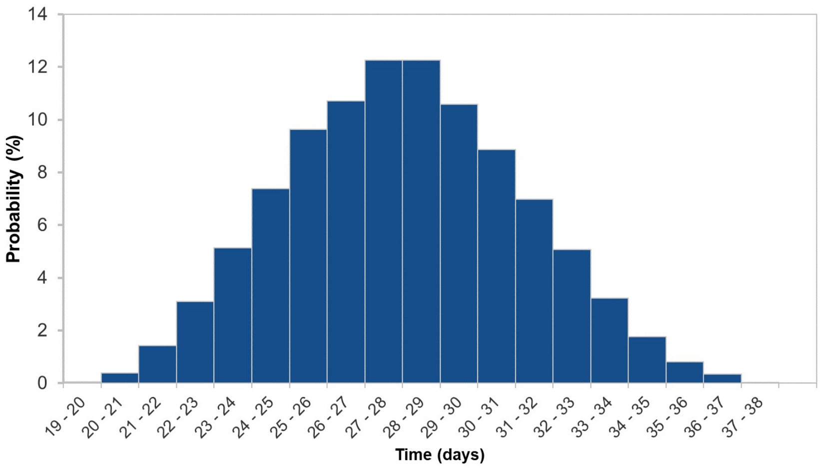


Figure 7.2: Time Probability Density Function for case A.

Figure 7.3 provides the individual phase duration, and easily illustrates that restoring seal 3 is the most time-consuming operation, with an estimated average duration of 5.69 days. The least time-consuming operation is the "cut casing and conductor"-phase. To cut the conductor and casing provides an average duration of approximately 14 minutes with the casing/conductor cutting technology, in addition to some extra time to run the cutting tool in and out of the well. Once the casing/conductor is cut downhole, it is pulled and cut in several sections using the ControlCutter technology, as explained in section 6.2.

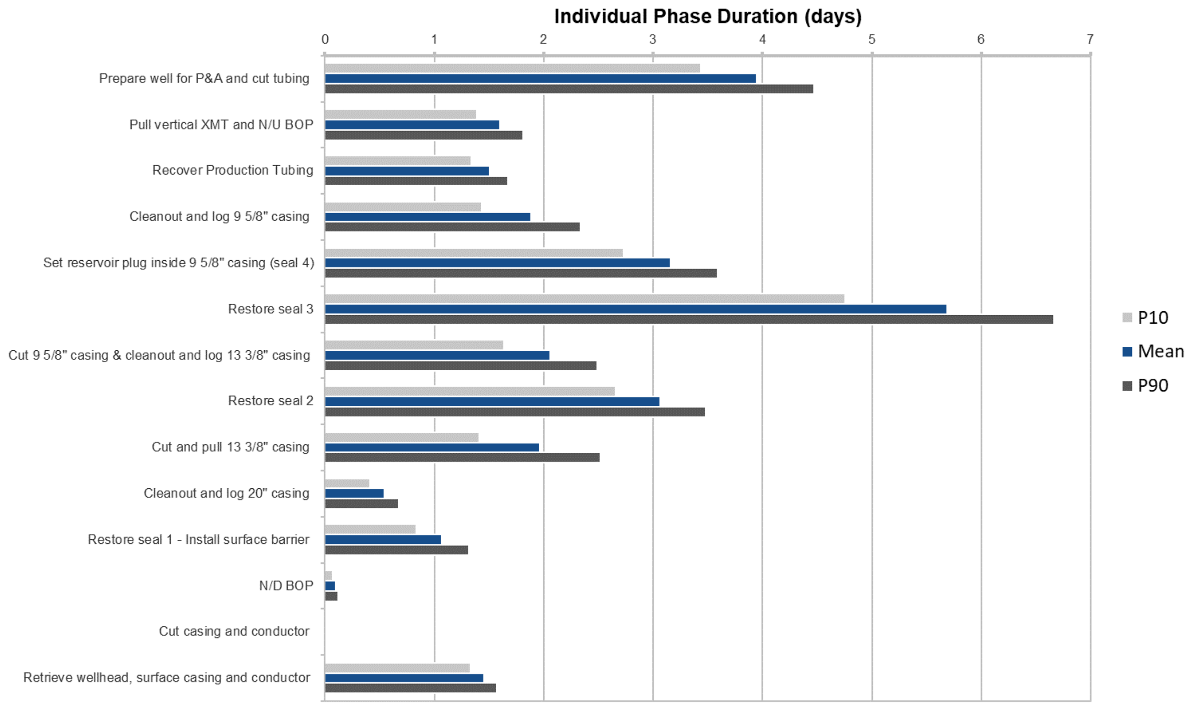


Figure 7.3: Simulated phase duration of case A.

The operational phases that provides the greatest effect on the variability of the project duration are the ones that show the greatest variance between the percentile bars. This information is essential when considering risk related to the model and the simulations. For case A, "Restore seal 3", "Cut and pull 13 3/8" casing" and "Prepare well for P&A and cut tubing" have thus the highest variance between the P10 and P90 percentile bars.

7.2 Case B

Seen by the CDF curve in figure 7.5, the estimated mean duration to complete the P&A operation for case B is 38.07 days. The P10 and P90 value is 33.86 days and 42.39 days, respectively. Detailed simulation results for the mean percentile, P10, P50 and P90, as well as a detailed operational breakdown with all phases and events can be found in appendix A5. In addition, the PDF curve explains that the number of days with the highest occurrence probability to complete the P&A operation is approximately 37 to 38 days, as shown in figure 7.5.

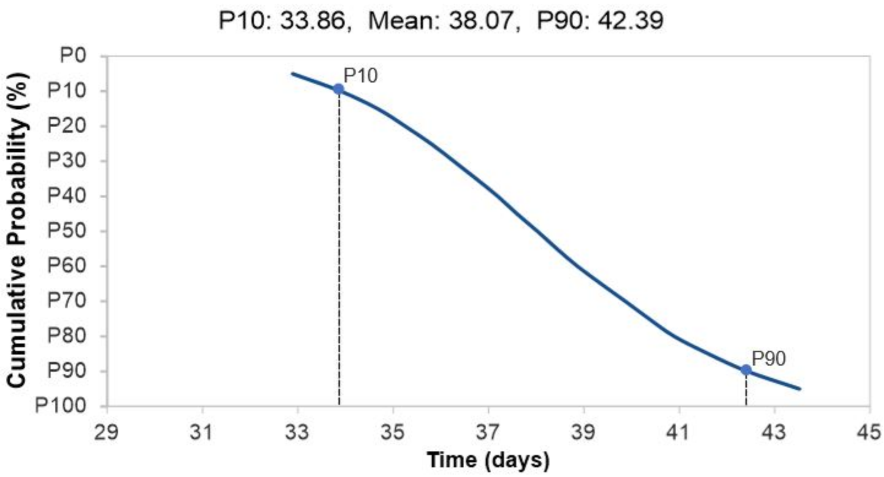


Figure 7.4: Time Cumulative Distribution Function for case B.

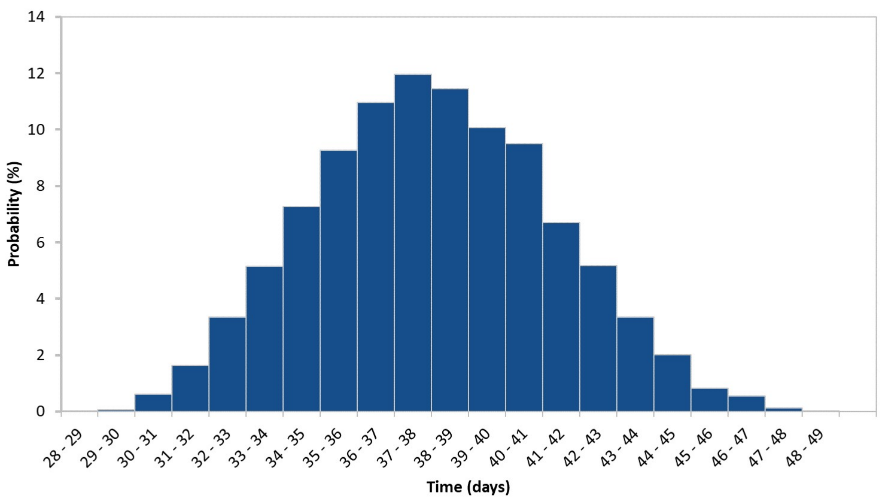


Figure 7.5: Time Probability Density Function for case B.

Except for the "Rig up Claxton WellRaizer"-phase name, the graphs in figure 7.6 illustrates that restoring seal 3 is the most time-consuming operation with an average duration of 5.68 days. In this case, the phase name with the absolute highest duration variance between the P10 and P90 percentile bars is "Restore seal 3".

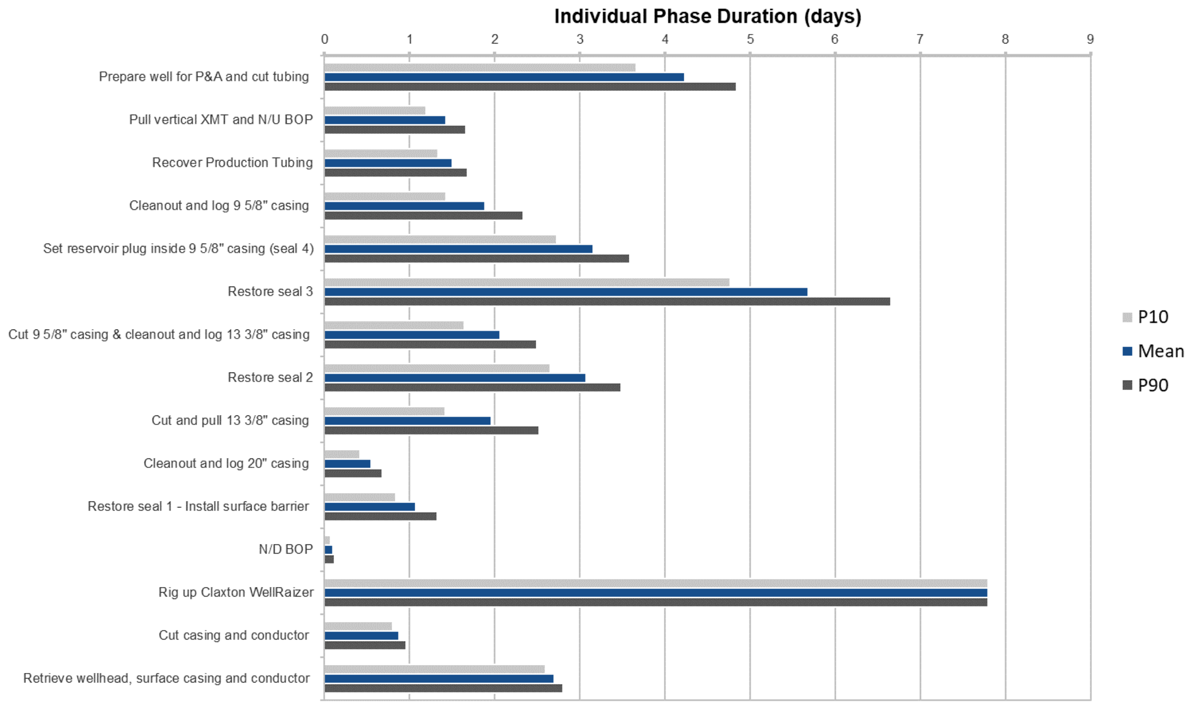


Figure 7.6: Simulated phase duration of case B.

7.3 Dream Well

Figure 7.7 and 7.8 displays the CDF and PDF curve of the Dream Well-case. The CDF curve illustrates a mean duration to complete the P&A operation of approximately 49.31 days, while the PDF curve explains that the time range with the highest occurrence probability is approximately 48 to 49 days. The P10 and P90 value of the CDF curve is 45.52 days and 53.29 days, respectively. Detailed simulation results for the mean percentile, P10, P50 and P90, as well as a detailed operational breakdown with all phases and events can be found in appendix A6.

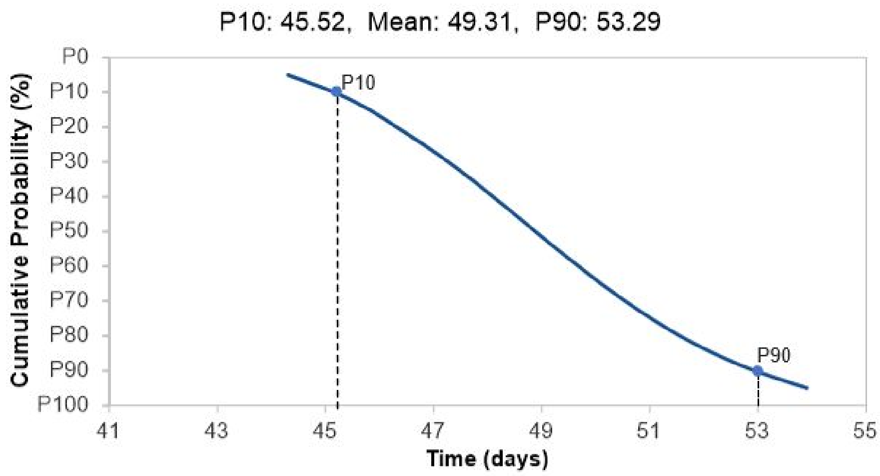


Figure 7.7: Time Cumulative Distribution Function for Dream Well.

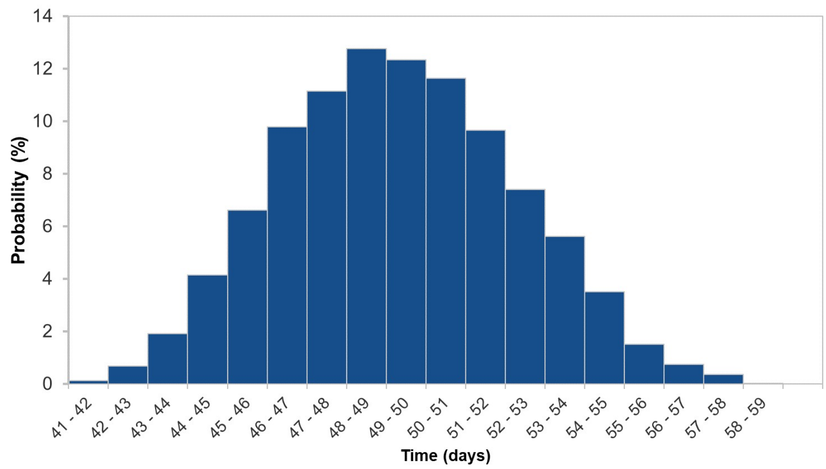


Figure 7.8: Time Probability Density Function for Dream Well.

The phase names with the highest mean time interval is "Restore seal 3", displayed by figure 7.9. The following phase names, "Recover Production Tubing" and "Cut 9 5/8" casing & cleanout and log 13 3/8" casing", have the highest variance between the P10 and P90 percentile bars in this case.

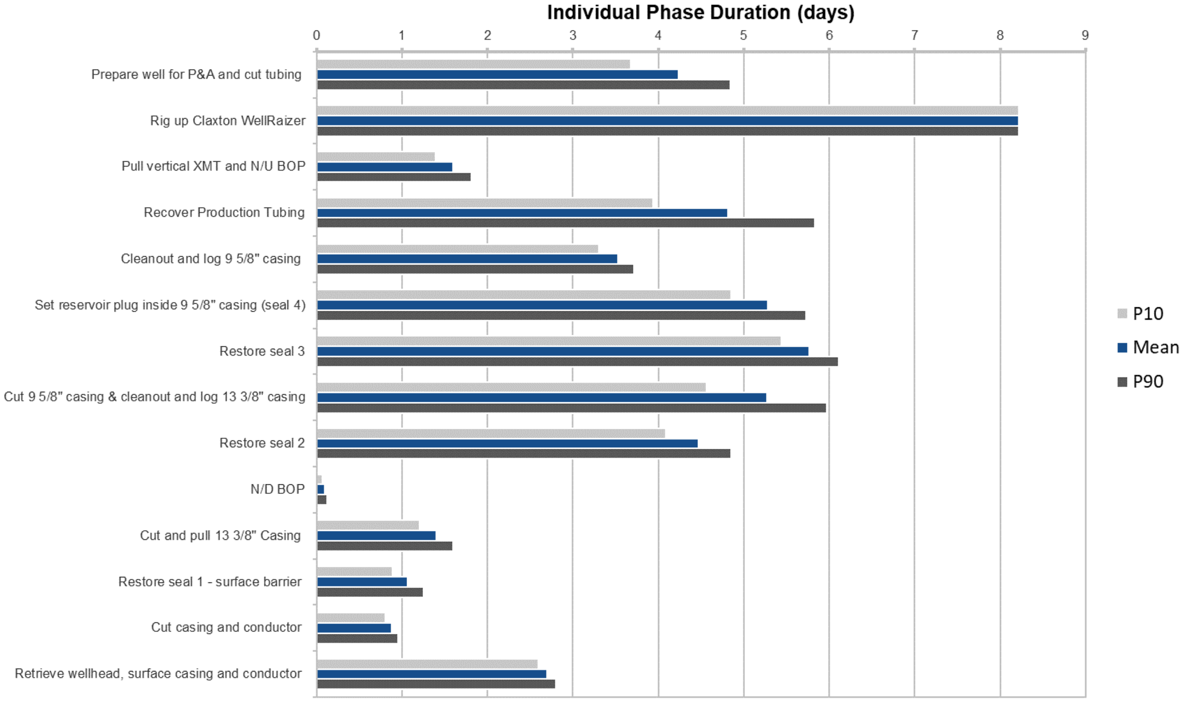


Figure 7.9: Simulated phase duration of Dream Well.

7.4 Time and Cost Comparison

The simulation results and statistical values of each case study are displayed in table 7.1. The statistical values represent the P10, P50, P90 and mean of the distribution. A summary of mean cost and duration for each case is also provided in figure 7.10. The graphs give an indication of which scenario that is most efficient regarding time and cost. As explained in section 6.1, the cost estimation is a result of multiplying the cost and spread rate of the involved technology with the forecasted operational time.

Table 7.1: Summary of all simulation results.

	Duration [days]				Cost [MNOK]			
	P10	P90	P50	Mean	P10	P90	P50	Mean
Case A: Rig-Rig-Rig-Rig	23.99	32.17	27.99	28.05	126.5	183.6	154.4	154.7
Case B: WI-Rig-Rig-WI	33.86	37.98	42.39	38.07	109.9	161.8	135.1	135.4
Dream Well: WI-WI-WI-WI	45.52	53.29	49.23	49.31	76.2	96.8	86.1	86.3

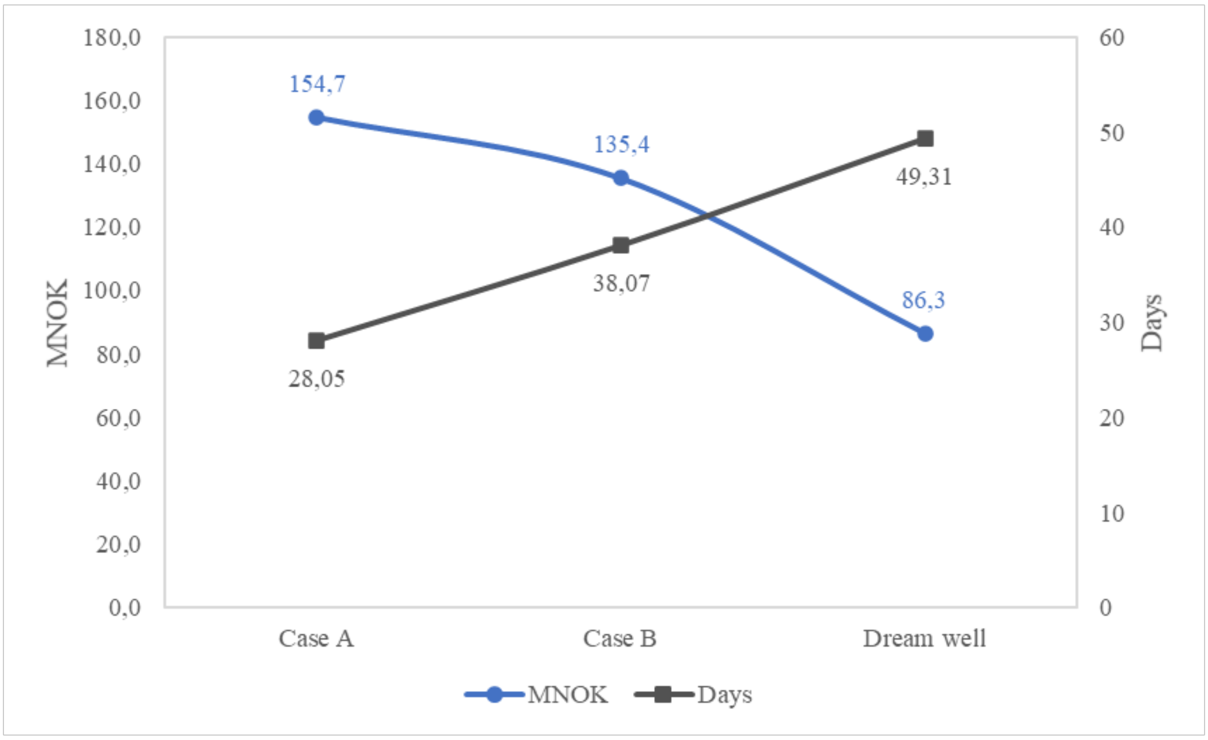


Figure 7.10: Mean total cost and duration of each case study.

For the Dream Well, the P50 value is approximately 49.23 days, which means that there is a 50% probability or chance that the operation can be delivered in 49.23 days or less. For case A and case B, P50 is 27.99 and 37.98 days, respectively. The distribution has a small degree of positive skewness, making P50 slightly smaller than the mean value. However, as this difference is not significant, this thesis will continue to operate with the mean output values in the further discussion.

Table 7.2 illustrates the removal/reduction in rig time for case B and Dream Well relative to case A. This is calculated from the values simulated for each operational phase. For case B, the rig time is reduced by approximately 19% relative to case A. For the Dream Well, the rig time is completely removed.

Table 7.2: Summary of removed/reduced rig time.

	Reduction in rig time relative to case A
Case A: Rig-Rig-Rig-Rig	0%
Case B: WI-Rig-Rig-WI	19%
Dream Well: WI-WI-WI-WI	100%

The total mean P&A cost for the Dream Well is approximately 86.3 MNOK, which is a decrease of 49.1 MNOK and 68.4 MNOK relative to case B and case A, respectively. As seen in figure 7.11, the biggest cost savings can be obtained in phase 1 and phase 2 of the P&A procedure. Meanwhile, phase 1 and 2 is also the most time-consuming phases. As figure 7.12 illustrates, there is an increase of approximately 15 days and 4 days when using well intervention equipment in phase 1 and 2, respectively. Rigging up the WellRaizer unit in case B and the Dream Well provides approximately 8 days.

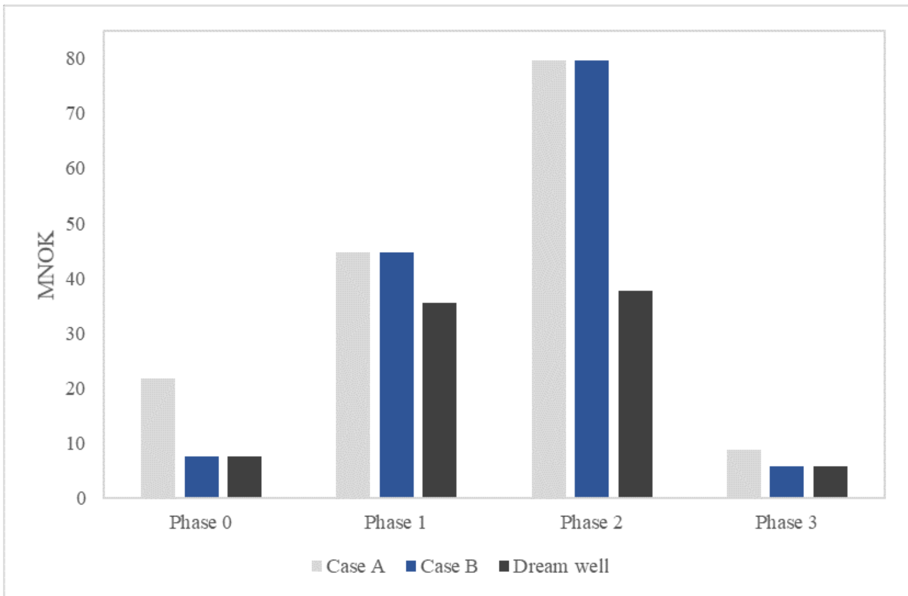


Figure 7.11: Mean total cost of each P&A phase.

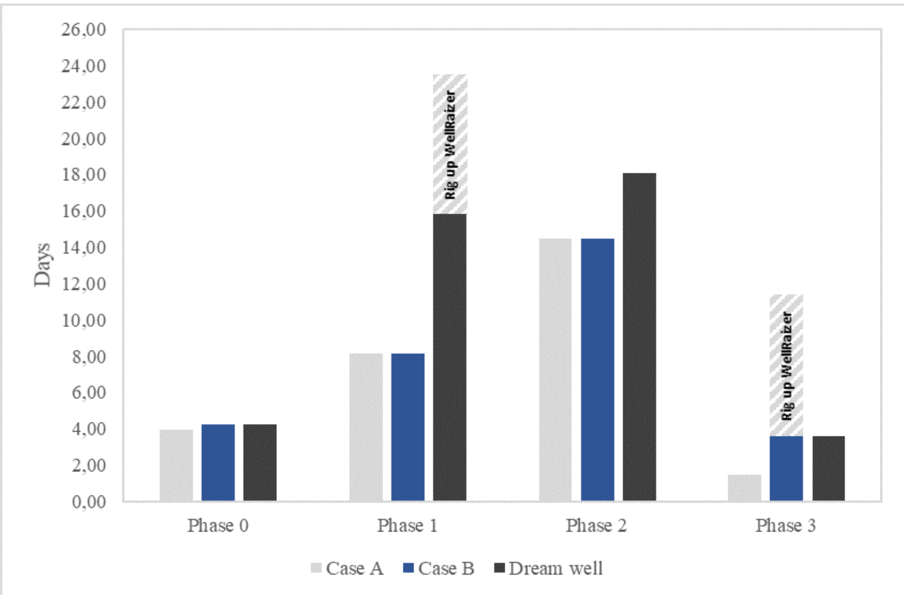


Figure 7.12: Mean duration of each P&A phase.

8 Discussion

The main goal of forecasting cost and duration of P&A operations is to predict an uncertain future and minimize risk. The results in this thesis shows that this can be done by using Monte Carlo simulations and constructing a suitable model based on historical data, expert opinions, and fundamental principles. Three different platform well abandonment approaches have been explored in this thesis: a rig-based approach, a rigless approach, as well as a combination of rig-based and rigless approach. The comparison between the case studies in chapter 6 is an attempt to suggest the most appropriate approach to platform P&A regarding cost and duration. Considering this, this chapter will discuss benefits and challenges related to the different approaches from a duration, cost, environmental and societal point of view, as well as limitations related to the simulation model.

8.1 Value Interpretation

The simulation results from the case studies have provided interesting observations. There are several ways to interpret the value of rigless P&A. The value perspective can be divided into the value of saved operational duration, and the value of saved rig-time. As observed from the simulation results, a rigless P&A approach increase the operational duration. With today's technology, it is more time-consuming to use well intervention equipment, rather than a rig, when the P&A complexity increase. The level of success of P&A operations should be measured in efficiency, which involves several factors other than only time spent. The operational efficiency is also based on how well the operation is performed regarding how cheaply it can be done, and thus the social benefits it can provide.

By operating completely rigless, the case studies show that the mean duration increases with 21.26 days relative to a rig-based approach, while operating with a combined rig-based and rigless approach increases the mean duration by 9.87 days. However, the mean removed rig time is 28.05 days for the Dream Well and the mean removed/reduced rig time is 5.41 days for case B, relative to case A. Even though the combined approach in case B reduce the rig time by only 5.41 days, a significant mean saving of 19.3 MNOK is obtained. Subject to a rough estimate, using this value for estimating a platform with 10 well slots to be P&Aed, a total of 193 MNOK could have been saved using this approach. Most people would naturally think that the less days spent on P&A of a well, the better and cheaper. This in itself is true when considering rig-based P&A, and the vast majority of other projects nowadays, as discussed in section 3.2. Compared to rigs, well intervention equipment is smaller and cheaper, and both results from case B and the Dream Well confirm that the total cost will be less even when the number of operational days increase significantly. The graphs in figure 7.10 in section 7.4 illustrates that even though the P&A duration increase by 75.8%, it will still become 55.8% cheaper if the P&A operation changes from completely rig-based to completely rigless. This thesis shows that when considering cost-savings, results from the case studies emphasize that time is not always money.

8.2 Phase Interpretation

As phase 1 and 2 is rig-based and identical in case A and B, and phase 0 and 3 is rigless and identical in case B and Dream Well, this provides a good overall picture of where the biggest savings can be obtained, and which operations that is the most time-consuming. Most time during the P&A operation is spent on phase 1 and 2 for all the three case studies. Hydraulic jacking units, such as the WellRaizer unit, has a less efficient operation speed than a rig, and this can be easily confirmed as phase 1 and 2 has increased with approximately 15 days and 4 days, respectively, for the Dream Well. These phases involve, for instance, cutting and pulling of tubing and casing strings, which is considered as complex operations. Hydraulic jacking units with the same properties as the WellRaizer, is very much smaller than a rig, but has nevertheless the ability to perform such operations. It is therefore conceivable that hydraulic jacks spend more time on these operations as they have a lower weight and less surface pulling force than a rig. In addition, as explained in section 4.2.1, the WellRaizer pulling operations are driven by a hydraulic jacking principle where each casing string is pulled in several sections. This procedure might increase the duration compared to a rig, which may have a more established workflow. However, performing phase 1 and 2 with well intervention equipment reduces the mean total cost by 9 MNOK and 42 MNOK, respectively, relative to the rig. Findings from Moeinikia (2016)'s study of rigless P&A on subsea wells, explained that substantial cost savings and released rig time could be obtained by using cost effective technologies and light weight intervention vessels instead of rigs in several phases. Wittberg (2017) suggested a rigless approach for reservoir abandonment on platforms that released six days of operational rig time and provided significant savings. This indicates that others' research and observations, even though they are based on a different basis, are definitely compliant with the results and findings of this thesis' case studies. There is a remarkably large difference in duration and cost by using substitutes to rig technology.

The difference in duration is less significant between the three case studies in phase 0, with a mean duration of approximately 4 days each. A rigless phase 0 turns out to be almost just as time efficient as a rig-based phase 0, which indicates that operators have invested in more knowledge and experience regarding a rigless phase 0. This can also explain why preparatory work for P&A is normally performed rigless on platform wells today, as mentioned in section 2.3. With this in mind, this emphasize the importance of investing in innovative solutions and substitutes to rigs, which in a long-term perspective can save the operators for large expenses. To highlight this point, a mean cost of 14 MNOK was saved by performing phase 0 without a rig in the case studies of this thesis.

As mentioned in section 6.2, the most efficient cutting technology on today's marked, delivered by ControlCutter, is used in phase 3 for case A. The cost of this technology is remarkably higher than the cost of conventional cutting technology, as the company must be compensated for saving the operation for a lot of rig time. If conventional cutting technology had been used in phase 3 in case A, the rig time would increased further. In the development of P&A operations, it is crucial to discuss and calculate whether it is ultimately cheaper to use expensive and effective technology rather than "cheap" and less effective conventional technology. As the simulation results clearly highlight in this thesis, large expenses can be saved by reducing the rig scope as high and often unpredictable rig rates can be neglected. The hydraulic jack spends almost three times longer performing phase 3 compared to the rig. Despite this, a mean cost of 3 MNOK is saved. This price difference is not as significant as in phase 0, 1 and 2, and this is due to the time-efficient cutting technology used in case A. This provides however an interesting fact, as the rigless approach is still cheaper although it is much more time-consuming in phase 3.

8.3 Overall Benefits

8.3.1 Social Profit

Another important aspect of the cost in this thesis is that 78% of the P&A expenses are paid by the Norwegian society through tax, as discussed in section 1.1. Using case B as an example, as this case represents a typical P&A scenario today, the mean total cost of abandoning one single well was estimated to 135.4 MNOK, as shown in section 7.4. 78% of this cost represents approximately 105 MNOK, which is thus required to be paid by the Norwegian state through tax regulations. For further discussion, one can assume that abandoning 10 wells at this cost implies NOK 1.3 billion, where approximately NOK 1 billion represents 78%. As explained in section 1.1, approximately 4808 wellbores on the NCS will be P&A'ed in the future. By using the mean total P&A cost from case B, a rough estimate indicates a total cost of approximately NOK 650 billion to abandon all these wells. If this number can be reduced, this will lead to a great gain for the state, as well as providing the opportunity for the saved expenses to benefit elsewhere in the state. This further strengthens the motivation to establish new approaches and better P&A technology that can reduce the costs. To compare, a rough cost estimate of abandoning one single well, 10 wells and 4808 wells gives approximately 86 MNOK, 863 MNOK and NOK 414 billion, respectively, by using the rigless Dream Well-approach and its mean total cost of 86 MNOK, given in section 7.4. 78% of these expenses indicate approximately 67 MNOK, 673 MNOK and NOK 322 billion, respectively, which will be paid by the state.

Noticeably, the cost results and the assumed long-term P&A costs indicate that the state and the society should be strongly involved in the development of P&A technology and rigless P&A. As this thesis has proven through comprehensive analysis, large expenses can be saved by releasing drilling rigs from the P&A scope, and the economic benefit to society is in fact greater than the economic benefit to the individual company. As a result of this, the development of rigless P&A approaches will be both useful to the industry and operators, and provide significant societal benefits and value.

8.3.2 Environmental Perspective

As explained in section 3.3, the MINV rig used in the P&A campaign at Valhall DP, was one of the first rigs that has been powered fully from shore. This indicates that the world is facing an extensive development potential in terms of making offshore operations, including P&A activities, more environmentally friendly. Well intervention equipment, presented in chapter 4, is suggested as more sustainable alternatives to rigs in order to meet the present and future environmental challenges. For instance, the WellRaizer technology emits only 20% as much emissions compared to a rig, as discussed in section 4.2.1. Even though well intervention equipment is often driven by diesel engine packages and generates its own power, this implies a step in the right direction towards the green shift. One interesting aspect for future research could be to investigate the opportunities of electrification of well intervention equipment such as hydraulic jacking units and wireline units. As the annual emissions was remarkably reduced by using the onshore powered MINV rig, it is reasonable to assume that electrified well intervention equipment will reduce the emissions to a further level. Rig activity can impose serious environmental consequences for our planet, and therefore investing in well intervention technology that can provide a positive effect on the environment should be highly appreciated.

8.3.3 The Power of Flexibility

In section 3.1, it was discussed that drilling rigs are traditionally used during P&A operations on platforms. In addition to save the total cost of P&A per well, rigless P&A is also advantageous as it avoid conflicts with other operations which depends on the use of a rig, such as drilling of exploration and production wells. Operators will achieve a greater degree of flexibility by releasing the rig from abandonment operations. This makes is possible to save time and cost as it is no longer necessary to be a part of the rig market and its fluctuations regarding supply and demand. This means that factors related to rig, which has previously been able to affect the productivity of P&A operations, will become absent. For operators, this will reduce the unpredictability of the total P&A cost and make it easier to plan and predict the total expense.

8.4 Model Limitations and Improvements

8.4.1 Scarce Data

First of all, this thesis examined a limited amount of data from wells at the Valhall DP field and Jotun B field. To raise quality and credibility, knowledge, and experiences from experts within the industry was incorporated into the simulation model, and this has been a major factor for mitigating risk and uncertainty related to the model output. Nevertheless, scarce data may have led to increased variance in the simulation output of the case studies. On the other hand, a main focus for the analysis and simulations in this thesis was to use input data from real wells with the same characteristics and qualities as the fictitious well. As the case studies covers operations which are considered complex and frequent in the various fields today, the data input used in this thesis represent a diversity that is believed to produce good forecasts and indications.

8.4.2 Percentile Variance

The operational phases that provides the greatest effect on the viability of the project duration are the ones with the greatest variance between the percentile bars, as described for each case study in chapter 7. The biggest time difference between P10 and P90 is for the individual phase "Restore seal 3", in case A and case B. This may indicate that additional engineering effort should be required in order to eliminate or mitigate risk identified in these phases to reduce this difference. It is not unlikely that the historical wells, as data in this thesis is retrieved from, has encountered uncertainties during this individual phase and has thus generated some deviations in the simulation model. For the Dream Well-case, cut-and-pull operations such as recovery of the production tubing and the 9 5/8" casing provided the greatest variance in duration, as figure 7.9 in section 7.3 shows. This might be a consequence of the fact that only a scarce amount of data currently exists for rigless pulling operations, and this makes it more challenging to estimate good simulation results. In the future, there will hopefully exist more data and knowledge related to completely rigless P&A, which can mitigate hazards and risk and provide better forecasts. In that way, one interesting aspect for future research could be to attempt to reduce the variance between the percentiles for the rigless operations in this thesis.

Even though variance occurs at different levels between P10 and P90 for the several individual phases, they are overall small compared to the total cost and duration for the case studies. For instance, the difference between P10 and P90 for the entire P&A operation is 8.18 days for case A, 4.12 days for case B and 7.77 days for the Dream Well. However, the difference between P10 and P90 regarding cost is only 21 MNOK for the dream well, while it is 57 MNOK and 53 MNOK for case A and B, respectively. This clearly reinforce that a rigless approach can withstand greater variation and uncertainty in terms of operational duration than rig-based approaches. One explanation for this is that exceeding the planned rig time will place a significant burden on the cost plan.

8.4.3 Reliability Appraisal

As discussed in section 5.2, several unforeseen events can occur and affect the duration of P&A operations. Figure 3.2 in section 3.2 reflects the duration of abandonment operations of wells at Valhall DP, using the same P&A approach as in case B. As shown in this figure, NPT and other uncertainty factors have been included in the time estimates. As a consequence, these factors are also incorporated into the simulation models in this thesis' case studies, as historical data from these wells has been used as explained in section 5.2. By including learnings from earlier P&A operations, it is reasonable to believe that this contributes to increase the reliability of the simulation output. The average operational duration per well in the P&A campaign at Valhall DP was approximately 40 days, and this also corresponds to the mean duration of 38.07 days in case B. This further indicates that the simulation models made in this thesis is suitable and provides realistic scenarios.

On another note, the mean total cost of the entire P&A operation for the Dream Well has been reduced by 55.8% relative to case A. This outcome corresponds to earlier studies, such as Straume (2016) research, explaining that the rig cost constitutes about 40-50% of the total P&A costs. It therefore makes sense that such large savings has been obtained for the Dream Well-case, as the rig activity has been removed. Considering this, it amplifies a high reliability of the estimation results of the Dream Well. Even though there has been a limited amount of available operational data regarding rigless P&A, this indicates that the collected data has been realistic and convenient for the case study.

8.5 Thesis Potential

This thesis chose to simulate the time and cost for abandoning one single well. A reason for this was to provide an indication of the P&A duration used per well with the different approaches, as well as to present the cost differences and where the biggest savings could be made during the operations. Raksagati (2012) modeled, simulated, and compared the cost and duration of batch P&A operations and single well operations using vessel technology on subsea wells. His study identified that increasing the number of wells in a batch operation would reduce the P&A cost per well. To build a similar simulation model could be interesting for this thesis as well, in order to investigate the effects on cost by performing P&A activities in a multi-well batch campaign. Since platform wells often have several well slots, it could also be relevant to estimate the potential savings in a rigless P&A batch campaign. Instead, this thesis chose to focus on the capabilities of well intervention equipment and the following savings this entail, with subject to the proviso that the "batch P&A" topic could be brought up for discussion in a later stage. For instance, as explained in section 4.2.1, the WellRaizer unit has the ability to skid between several well slots. A batch P&A campaign on platform wells based on the Dream Well approach and by using a hydraulic jacking technology can therefore be highly relevant and effective in the future. Based on the simulation results provided by this thesis, it is very likely that rigless P&A operations on multiple wells in a batch campaign will be a cost-effective approach. This also corresponds to the information given in section 3.2, which proved a continuous improvement progress of operational duration for the P&A batch campaign at Valhall DP due to a learning effect on the outcome and effective technology. Compared with subsea fields with multiple wells, the advantage of doing a P&A batch on platform wells with several slots is that it does not require any transit time of technology between the wells. All the involved operational equipment will be on board the platform and available for use on each well slot, which will thus improve both the time and cost efficiency per well.

9 Conclusion

9.1 Conclusive Summary

As the number of wells to be abandoned will increase in the forthcoming years, there will be a great need and a high demand within the industry to develop cost-efficient, and sustainable methods to perform P&A operations on wells. Throughout this thesis, three case studies with different platform well abandonment approaches have been explored: a rig-based approach, a rigless approach, and a combination of rig-based and rigless approach. The rigless approach for platform P&A has been investigated and presented as an alternative to the conventional rig-based P&A operation. By using data collected from P&A operations at Valhall DP and Jotun B, as well as experience input from experts, three Monte Carlo simulation models has been derived to forecast cost and duration of a fictitious platform well. As a result, the simulation output has shown a significant difference in cost and duration between the three P&A case studies. Relative to the rig-based approach, a mean cost of 68.4 MNOK was saved using the rigless approach.

One main finding of this thesis is that it is technically possible for well intervention equipment to perform a complete platform P&A operation in a reliable, cost-efficient, and sustainable manner, for a large number of well designs. The rigless approach was found to be very time-consuming compared to the rig-based approach, and phase 1 and 2 of the general P&A procedure turned out to be the most complex, time-consuming, and expensive part of the operational scope. This could indicate that an increased focus on optimizing rigless technology within these phases can lead to even greater cost savings. It is clear that removing and reducing the rig scope for P&A and investing time in developing solutions and knowledge within the field of rigless P&A would be beneficial for both the society and the industry in a cost perspective.

Even by only partially reducing the rig scope, as in case B, significant cost-savings were made. The partly rigless approach reduced the rig scope by 19% and the mean total cost by approximately 19.3 MNOK. Lastly, several factors which cause uncertainties and fluctuations in time and cost can be neglected by removing and reducing the rig scope. After analyzing the simulation results, one can conclude that well intervention equipment obviously defends the viability of rigless P&A, as it has the ability to do P&A at a significantly lower cost than a rig.

9.2 Recommendation for Further Research

As a result of this thesis, some points of recommendations for future work can be conducted in order to further improve time and cost efficiency of rigless P&A operations:

- This thesis has forecasted cost and duration for P&A of one single well. In reality, a platform often has several well slots. Future research should investigate the potential effects on cost and duration a rigless batch P&A campaign can provide. This way, one can identify an even greater extent of possible cost reductions per well for P&A operations.

- Hopefully, highlights from this thesis can contribute to further motivation and drive for the development of rigless P&A on platforms. One of the main challenges experienced when writing this thesis was to collect a sufficient amount of relevant data and information. An increase in rigless performed activities using well intervention equipment on the NCS will provide more available data, experience, and strength of knowledge regarding risk and uncertainties. For further studies, a more complex database can become valuable when forecasting and analyzing cost and duration for rigless P&A, and reduce today's operational percentile range.

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Appendix

A1 MINV - Daily Rate Forecast

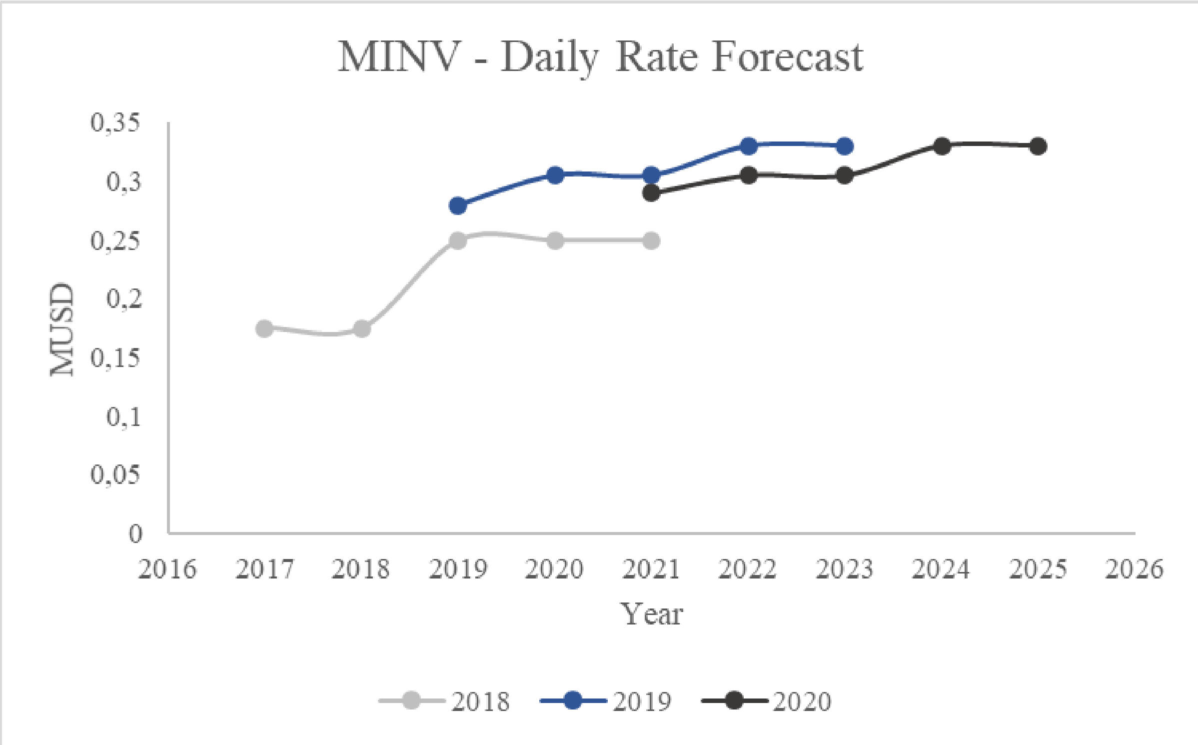

Figure A1.1: MINV - Development of forecasted daily rental cost

A2 Cost of Equipment and Technology

Table A2.1: Cost input used for cost estimation in case studies.
Data provided by internal resources in Aker BP.

	Daily Spread rate [MNOK]
Wireline	0.50
WellRaizer	0.37
Jack-up Rig	4.99
BOP + HP riser	0.10
Drill pipe	0.10
Jacking system	0.10
Control cutter	0.46
Norse cutter	0.15
Rigless platform service rate	0.83
Equipment package	0.35
Pipe handling system	0.05
Tangible cost	0.05

A3 Well Schematic for Case Studies

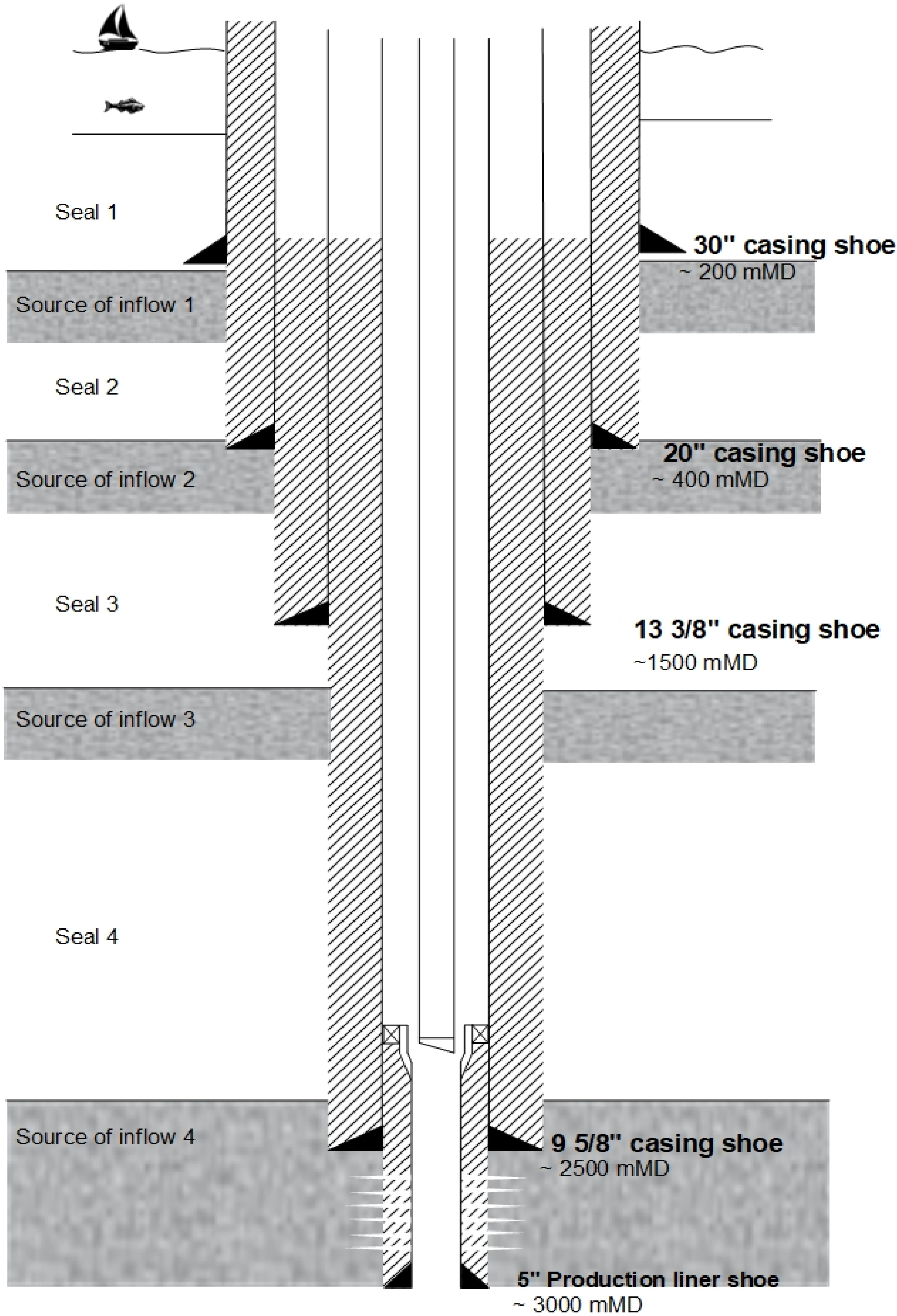

Figure A3.1: Well Schematic for Case Studies

A4 Simulation Results for Case A

Table A4.1: Detailed analysis results for case A.

Name	Example Scenario (Hours)											
	Mean			P10			P50			P90		
Prepare well for P&A and cut tubing												
Events	Duration	Project Risk	Sum	Duration	Project Risk	Sum	Duration	Project Risk	Sum	Duration	Project Risk	Sum
Drift run and caliper run	6,28	1,01	7,29	5,23	0,84	6,07	6,27	1,00	7,27	7,79	1,25	9,03
Integrity logging	6,40	1,02	7,42	5,49	0,88	6,36	6,39	1,02	7,41	7,73	1,24	8,97
Kill well, bullhead cement	9,03	1,45	10,48	7,83	1,25	9,08	9,02	1,44	10,46	10,18	1,63	11,81
Install deep set bridge plug and test plug	14,06	2,25	16,31	11,66	1,87	13,53	14,03	2,24	16,28	16,37	2,62	18,99
Punch tubing above production packer	7,01	1,12	8,13	6,61	1,06	7,67	7,01	1,12	8,13	7,39	1,18	8,58
Circulate heavy fluid (tubing+annulus)	2,26	0,36	2,63	1,76	0,28	2,04	2,26	0,36	2,62	2,74	0,44	3,18
Cut tubing above the production packer	6,01	0,96	6,97	5,61	0,90	6,51	6,01	0,96	6,97	6,39	1,02	7,42
Displace annulus and tubing to kill fluid/brine	3,53	0,56	4,09	2,53	0,40	2,93	3,51	0,56	4,08	4,49	0,72	5,20
Install downhole safety valve protection sleeve	9,78	1,56	11,34	8,53	1,37	9,90	9,76	1,56	11,32	10,81	1,73	12,54
Place tubing hanger plug in production and annulus bore	17,15	2,74	19,90	16,20	2,59	18,80	17,14	2,74	19,88	18,14	2,90	21,05
Risks												
NPT - WOW	4,89			4,29			4,88			5,52		
NPT - P&A risk	8,15			7,15			8,14			9,20		
Pull vertical XMT and N/U BOP												
Events	Duration	Project Risk	Sum	Duration	Project Risk	Sum	Duration	Project Risk	Sum	Duration	Project Risk	Sum
Pull vertical XMT to surface	15,54	2,49	18,02	14,14	2,26	16,40	15,52	2,48	18,00	16,88	2,70	19,58
Install BOP	17,66	2,83	20,49	15,23	2,44	17,66	17,63	2,82	20,45	20,00	3,20	23,20
Risks												
NPT - WOW	1,99			1,76			1,99			2,21		
NPT - P&A risk	3,32			2,94			3,31			3,69		
Recover Production Tubing												
Events	Duration	Project Risk	Sum	Duration	Project Risk	Sum	Duration	Project Risk	Sum	Duration	Project Risk	Sum
Pull tubing hanger and tubing	31,22	5,00	36,22	28,41	4,55	32,96	31,19	4,99	36,18	33,92	5,43	39,35
Risks												
NPT - WOW	1,87			1,70			1,87			2,04		
NPT - P&A risk	3,12			2,84			3,12			3,39		
Cleanout and log 9 5/8" casing												
Events	Duration	Project Risk	Sum	Duration	Project Risk	Sum	Duration	Project Risk	Sum	Duration	Project Risk	Sum
Clean 9 5/8" casing	32,67	5,23	37,90	26,01	4,16	30,17	32,59	5,21	37,80	39,07	6,25	45,32
Log 9 5/8" casing	6,27	1,00	7,28	5,38	0,86	6,24	6,26	1,00	7,26	7,58	1,21	8,79
Risks												
NPT - WOW	2,34			1,88			2,33			2,80		
NPT - P&A risk	3,89			3,14			3,88			4,66		
Set reservoir plug inside 9 5/8" casing (seal 4)												
Events	Duration	Project Risk	Sum	Duration	Project Risk	Sum	Duration	Project Risk	Sum	Duration	Project Risk	Sum
Set 9 5/8" bridge plug	13,56	2,17	15,73	11,25	1,80	13,05	13,53	2,16	15,69	15,78	2,52	18,30
Set primary cement plug inside 9 5/8" casing	17,94	2,87	20,81	16,98	2,72	19,70	17,93	2,87	20,80	18,87	3,02	21,89
Wait on cement and test plug	8,00	1,28	9,28	5,87	0,94	6,81	7,97	1,28	9,24	10,16	1,63	11,79
Set secondary plug inside 9 5/8" casing	17,94	2,87	20,81	16,98	2,72	19,70	17,93	2,87	20,80	18,87	3,02	21,89
Wait on cement and test plug	8,00	1,28	9,28	5,87	0,94	6,81	7,97	1,28	9,24	10,16	1,63	11,79
Risks												
NPT - WOW	3,93			3,42			3,92			4,43		
NPT - P&A risk	6,54			5,70			6,53			7,38		
Restore seal 3												
Events	Duration	Project Risk	Sum	Duration	Project Risk	Sum	Duration	Project Risk	Sum	Duration	Project Risk	Sum
PWC - Primary plug	50,65	8,10	58,75	44,01	7,04	51,05	50,56	8,09	58,65	57,93	9,27	67,20
Wait on cement and test cement plug	8,00	1,28	9,28	5,87	0,94	6,81	7,97	1,28	9,24	10,16	1,63	11,79
PWC - Secondary plug	50,65	8,10	58,75	44,01	7,04	51,05	50,56	8,09	58,65	57,93	9,27	67,20
Wait on cement and test plug	8,00	1,28	9,28	5,87	0,94	6,81	7,97	1,28	9,24	10,16	1,63	11,79
Risks												
NPT - WOW	7,04			5,99			7,02			8,17		
NPT - P&A risk	11,73			9,98			11,71			13,62		
Cut 9 5/8" casing & cleanout and log 13 3/8" casing												
Events	Duration	Project Risk	Sum	Duration	Project Risk	Sum	Duration	Project Risk	Sum	Duration	Project Risk	Sum
Cut and pull 9 5/8" casing	29,38	4,70	34,08	24,38	3,90	28,28	29,31	4,69	34,01	34,18	5,47	39,65
Cleanout 13 3/8" casing	10,97	1,76	12,73	8,55	1,37	9,92	10,94	1,75	12,69	13,30	2,13	15,43
Log 13 3/8" casing	2,43	0,39	2,82	2,08	0,33	2,42	2,43	0,39	2,81	2,94	0,47	3,41
Risks												
NPT - WOW	2,57			2,10			2,56			3,03		
NPT - P&A risk	4,28			3,50			4,27			5,04		
Restore seal 2												
Events	Duration	Project Risk	Sum	Duration	Project Risk	Sum	Duration	Project Risk	Sum	Duration	Project Risk	Sum
Install 13 3/8" bridge plug	11,70	1,87	13,57	9,73	1,56	11,29	11,68	1,87	13,54	13,59	2,17	15,77
Set primary cement plug inside 13 3/8" casing	17,94	2,87	20,81	16,98	2,72	19,70	17,93	2,87	20,80	18,87	3,02	21,89
Wait on cement and test plug	8,00	1,28	9,28	5,87	0,94	6,81	7,97	1,28	9,24	10,16	1,63	11,79
Set secondary cement plug inside 13 3/8" casing	17,94	2,87	20,81	16,98	2,72	19,70	17,93	2,87	20,80	18,87	3,02	21,89
Wait on cement and test plug	8,00	1,28	9,28	5,87	0,94	6,81	7,97	1,28	9,24	10,16	1,63	11,79
Risks												
NPT - WOW	3,82			3,33			3,81			4,30		
NPT - P&A risk	6,36			5,54			6,35			7,16		
Cut and pull 13 3/8" casing												
Events	Duration	Project Risk	Sum	Duration	Project Risk	Sum	Duration	Project Risk	Sum	Duration	Project Risk	Sum
Cut and pull 13 3/8" casing	40,81	6,53	47,35	31,85	5,10	36,95	40,70	6,51	47,21	49,42	7,91	57,33
Risks												
NPT - WOW	2,45			1,91			2,44			2,97		
NPT - P&A risk	4,08			3,19			4,07			4,94		
Cleanout and log 20" casing												
Events	Duration	Project Risk	Sum	Duration	Project Risk	Sum	Duration	Project Risk	Sum	Duration	Project Risk	Sum
Cleanout 20" casing	10,94	1,75	12,69	8,83	1,41	10,24	10,91	1,75	12,66	12,97	2,08	15,05
Log 20" casing	0,38	0,06	0,45	0,33	0,05	0,38	0,38	0,06	0,44	0,46	0,07	0,54
Risks												
NPT - WOW	0,68			0,55			0,68			0,81		
NPT - P&A risk	1,13			0,92			1,13			1,34		
Restore seal 1 - Install surface barrier												
Events	Duration	Project Risk	Sum	Duration	Project Risk	Sum	Duration	Project Risk	Sum	Duration	Project Risk	Sum
Set 20" EZSV	7,12	1,14	8,26	5,72	0,92	6,64	7,10	1,14	8,24	8,97	1,44	10,41
Install environmental cement plug	6,87	1,10	7,97	6,13	0,98	7,11	6,86	1,10	7,96	7,58	1,21	8,79
Wait on cement and test plug	8,00	1,28	9,28	5,87	0,94	6,81	7,97	1,28	9,24	10,16	1,63	11,79
Risks												
NPT - WOW	1,32			1,06			1,32			1,60		
NPT - P&A risk	2,20			1,77			2,19			2,67		
N/D BOP												
Events	Duration	Project Risk	Sum	Duration	Project Risk	Sum	Duration	Project Risk	Sum	Duration	Project Risk	Sum
N/D BOP	2,01	0,32	2,33	1,61	0,26	1,87	2,01	0,32	2,33	2,39	0,38	2,78
Risks												
NPT - WOW	0,12			0,10			0,12			0,14		
NPT - P&A risk	0,20			0,16			0,20			0,24		
Cut casing and conductor												
Events	Duration	Project Risk	Sum	Duration	Project Risk	Sum	Duration	Project Risk	Sum	Duration	Project Risk	Sum
Drill and pin conductor and casings	0,06	0,01	0,07	0,06	0,01	0,07	0,06	0,01	0,07	0,06	0,01	0,07
Conduct cut	0,05	0,01	0,06	0,05	0,01	0,06	0,05	0,01	0,06	0,05	0,01	0,06
Risks												
NPT - WOW	0,01			0,01			0,01			0,01		
NPT - P&A risk	0,01			0,01			0,01			0,01		
Retrieve wellhead, surface casing and conductor												
Events	Duration	Project Risk	Sum	Duration	Project Risk	Sum	Duration	Project Risk	Sum	Duration	Project Risk	Sum
Retrieve Wellhead and conductor casing	30,05	4,81	34,86	28,05	4,49	32,54	30,03	4,80	34,83	31,97	5,12	37,09
Risks												
NPT - WOW	1,80			1,68			1,80			1,92		
NPT - P&A risk	3,01			2,81			3,00			3,20		
Total (hours)	**673,15**			**575,68**			**671,84**			**772,15**		
Total (days)	**28,05**			**23,99**			**27,99**			**32,17**		

A5 Simulation Results for Case B

Table A5.1: Detailed analysis results for case B.

Name	Example Scenario (Hours)											
	Mean			P10			P50			P90		
Prepare well for P&A and cut tubing												
Events	Duration	Project Risk	Sum	Duration	Project Risk	Sum	Duration	Project Risk	Sum	Duration	Project Risk	Sum
Drift run and caliper run	6,29	1,01	7,29	5,23	0,84	6,07	6,26	1,00	7,27	7,80	1,25	9,04
Integrity logging	6,40	1,02	7,43	5,49	0,88	6,37	6,38	1,02	7,40	7,74	1,24	8,98
Kill well, bullhead cement	9,04	1,45	10,48	7,83	1,25	9,09	9,01	1,44	10,45	10,19	1,63	11,82
Install deep set bridge plug and test plug	9,03	1,44	10,47	8,03	1,28	9,31	9,01	1,44	10,45	9,99	1,60	11,59
Punch tubing above production packer	7,01	1,12	8,13	6,61	1,06	7,67	7,00	1,12	8,12	7,40	1,18	8,58
Circulate heavy fluid (tubing+annulus)	2,27	0,36	2,63	1,76	0,28	2,05	2,26	0,36	2,62	2,75	0,44	3,18
Cut tubing above the production packer	15,88	2,54	18,42	13,49	2,16	15,64	15,83	2,53	18,36	19,28	3,08	22,36
Displace annulus and tubing to kill fluid/brine	4,77	0,76	5,53	3,91	0,62	4,53	4,75	0,76	5,51	5,75	0,92	6,67
Install downhole safety valve protection sleeve	9,78	1,56	11,34	8,54	1,37	9,90	9,76	1,56	11,32	10,82	1,73	12,55
Place tubing hanger plug in production and annulus bore	16,51	2,64	19,15	15,03	2,41	17,44	16,48	2,64	19,11	17,90	2,86	20,76
Risks												
NPT - WOW	5,22			4,55			5,20			5,98		
NPT - P&A risk	8,70			7,59			8,67			9,96		
Pull vertical XMT and N/U BOP												
Events	Duration	Project Risk	Sum	Duration	Project Risk	Sum	Duration	Project Risk	Sum	Duration	Project Risk	Sum
Pull vertical XMT to surface	12,06	1,93	13,99	10,06	1,61	11,66	12,02	1,92	13,94	13,98	2,24	16,22
Install BOP	17,67	2,83	20,50	15,23	2,44	17,67	17,63	2,82	20,45	20,01	3,20	23,22
Risks												
NPT - WOW	1,78			1,52			1,78			2,04		
NPT - P&A risk	2,97			2,53			2,96			3,40		
Recover Production Tubing												
Events	Duration	Project Risk	Sum	Duration	Project Risk	Sum	Duration	Project Risk	Sum	Duration	Project Risk	Sum
Pull tubing hanger and tubing	31,23	5,00	36,23	28,42	4,55	32,96	31,18	4,99	36,17	33,94	5,43	39,37
Risks												
NPT - WOW	1,87			1,70			1,87			2,04		
NPT - P&A risk	3,12			2,84			3,12			3,39		
Cleanout and log 9 5/8" casing												
Events	Duration	Project Risk	Sum	Duration	Project Risk	Sum	Duration	Project Risk	Sum	Duration	Project Risk	Sum
Clean 9 5/8" casing	32,70	5,23	37,93	26,03	4,16	30,19	32,57	5,21	37,78	39,10	6,26	45,36
Log 9 5/8" casing	6,28	1,00	7,28	5,38	0,86	6,24	6,26	1,00	7,26	7,58	1,21	8,80
Risks												
NPT - WOW	2,34			1,88			2,33			2,80		
NPT - P&A risk	3,90			3,14			3,88			4,67		
Set reservoir plug inside 9 5/8" casing (seal 4)												
Events	Duration	Project Risk	Sum	Duration	Project Risk	Sum	Duration	Project Risk	Sum	Duration	Project Risk	Sum
Set 9 5/8" bridge plug	13,57	2,17	15,74	11,26	1,80	13,06	13,52	2,16	15,69	15,79	2,53	18,31
Set primary cement plug inside 9 5/8" casing	17,95	2,87	20,82	16,98	2,72	19,70	17,93	2,87	20,80	18,87	3,02	21,89
Wait on cement and test plug	8,01	1,28	9,29	5,87	0,94	6,81	7,96	1,27	9,24	10,17	1,63	11,80
Set secondary plug inside 9 5/8" casing	17,95	2,87	20,82	16,98	2,72	19,70	17,93	2,87	20,80	18,87	3,02	21,89
Wait on cement and test plug	8,01	1,28	9,29	5,87	0,94	6,81	7,96	1,27	9,24	10,17	1,63	11,80
Risks												
NPT - WOW	3,93			3,42			3,92			4,43		
NPT - P&A risk	6,55			5,70			6,53			7,39		
Restore seal 3												
Events	Duration	Project Risk	Sum	Duration	Project Risk	Sum	Duration	Project Risk	Sum	Duration	Project Risk	Sum
PWC - Primary plug	50,68	8,11	58,79	44,02	7,04	51,07	50,54	8,09	58,63	57,97	9,28	67,25
Wait on cement and test cement plug	7,82	1,25	9,07	5,72	0,91	6,63	7,78	1,24	9,02	10,00	1,60	11,60
PWC - Secondary plug	50,68	8,11	58,79	44,02	7,04	51,07	50,54	8,09	58,63	57,97	9,28	67,25
Wait on cement and test plug	8,01	1,28	9,29	5,87	0,94	6,81	7,96	1,27	9,24	10,17	1,63	11,80
Risks												
NPT - WOW	7,03			5,98			7,01			8,17		
NPT - P&A risk	11,72			9,96			11,68			13,61		
Cut and pull9 5/8" casing & cleanout and log 13 3/8" casing												
Events	Duration	Project Risk	Sum	Duration	Project Risk	Sum	Duration	Project Risk	Sum	Duration	Project Risk	Sum
Cut and pull 9 5/8" casing	29,40	4,70	34,10	24,39	3,90	28,29	29,30	4,69	33,99	34,21	5,47	39,68
Cleanout 13 3/8" casing	10,98	1,76	12,74	8,55	1,37	9,92	10,93	1,75	12,68	13,32	2,13	15,45
Log 13 3/8" casing	2,43	0,39	2,82	2,09	0,33	2,42	2,43	0,39	2,81	2,94	0,47	3,41
Risks												
NPT - WOW	2,57			2,10			2,56			3,03		
NPT - P&A risk	4,28			3,50			4,27			5,05		
Restore seal 2												
Events	Duration	Project Risk	Sum	Duration	Project Risk	Sum	Duration	Project Risk	Sum	Duration	Project Risk	Sum
Install 13 3/8" bridge plug	11,71	1,87	13,58	9,74	1,56	11,29	11,67	1,87	13,54	13,60	2,18	15,78
Set primary cement plug inside 13 3/8" casing	17,95	2,87	20,82	16,98	2,72	19,70	17,93	2,87	20,80	18,87	3,02	21,89
Wait on cement and test plug	8,01	1,28	9,29	5,87	0,94	6,81	7,96	1,27	9,24	10,17	1,63	11,80
Set secondary cement plug inside 13 3/8" casing	17,95	2,87	20,82	16,98	2,72	19,70	17,93	2,87	20,80	18,87	3,02	21,89
Wait on cement and test plug	8,01	1,28	9,29	5,87	0,94	6,81	7,96	1,27	9,24	10,17	1,63	11,80
Risks												
NPT - WOW	3,82			3,33			3,81			4,30		
NPT - P&A risk	6,36			5,54			6,35			7,17		
Cut and pull 13 3/8" casing												
Events	Duration	Project Risk	Sum	Duration	Project Risk	Sum	Duration	Project Risk	Sum	Duration	Project Risk	Sum
Cut and pull 13 3/8" casing	40,85	6,54	47,39	31,87	5,10	36,97	40,68	6,51	47,18	49,47	7,91	57,38
Risks												
NPT - WOW	2,45			1,91			2,44			2,97		
NPT - P&A risk	4,09			3,19			4,07			4,95		
Cleanout and log 20" casing												
Events	Duration	Project Risk	Sum	Duration	Project Risk	Sum	Duration	Project Risk	Sum	Duration	Project Risk	Sum
Cleanout 20" casing	10,95	1,75	12,70	8,83	1,41	10,25	10,91	1,75	12,65	12,98	2,08	15,06
Log 20" casing	0,38	0,06	0,45	0,33	0,05	0,38	0,38	0,06	0,44	0,46	0,07	0,54
Risks												
NPT - WOW	0,68			0,55			0,68			0,81		
NPT - P&A risk	1,13			0,92			1,13			1,34		
Restore seal 1 - Install surface barrier												
Events	Duration	Project Risk	Sum	Duration	Project Risk	Sum	Duration	Project Risk	Sum	Duration	Project Risk	Sum
Set 20" EZSV	7,13	1,14	8,27	5,72	0,92	6,64	7,10	1,14	8,23	8,99	1,44	10,42
Install environmental cement plug	6,87	1,10	7,97	6,13	0,98	7,11	6,86	1,10	7,96	7,58	1,21	8,80
Wait on cement and test plug	8,01	1,28	9,29	5,87	0,94	6,81	7,96	1,27	9,24	10,17	1,63	11,80
Risks												
NPT - WOW	1,32			1,06			1,32			1,60		
NPT - P&A risk	2,20			1,77			2,19			2,67		
N/D BOP												
Events	Duration	Project Risk	Sum	Duration	Project Risk	Sum	Duration	Project Risk	Sum	Duration	Project Risk	Sum
N/D BOP	2,01	0,32	2,33	1,61	0,26	1,87	2,00	0,32	2,32	2,40	0,38	2,78
Risks												
NPT - WOW	0,12			0,10			0,12			0,14		
NPT - P&A risk	0,20			0,16			0,20			0,24		
Rig up Claxton WellRaizer												
Events	Duration	Project Risk	Sum	Duration	Project Risk	Sum	Duration	Project Risk	Sum	Duration	Project Risk	Sum
Rig up Claxton WellRaizer	170,00	17,00	187,00	170,00	17,00	187,00	170,00	17,00	187,00	170,00	17,00	187,00
Risks												
NPT - P&A risk	17,00			17,00			17,00			17,00		
Cut casing and conductor												
Events	Duration	Project Risk	Sum	Duration	Project Risk	Sum	Duration	Project Risk	Sum	Duration	Project Risk	Sum
Drill and pin conductor	0,69	0,11	0,80	0,60	0,10	0,69	0,68	0,11	0,79	0,79	0,13	0,91
Cut casings and conductor	17,52	2,80	20,33	16,30	2,61	18,91	17,50	2,80	20,30	18,69	2,99	21,68
Risks												
NPT - WOW	1,09			1,01			1,09			1,17		
NPT - P&A risk	1,82			1,69			1,82			1,95		
Retrieve wellhead, surface casing and conductor												
Events	Duration	Project Risk	Sum	Duration	Project Risk	Sum	Duration	Project Risk	Sum	Duration	Project Risk	Sum
Pull up and run landing string	11,89	1,90	13,79	11,27	1,80	13,07	11,88	1,90	13,78	12,41	1,99	14,39
Engage to wellhead and surface	11,75	1,88	13,63	11,40	1,82	13,23	11,74	1,88	13,62	11,93	1,91	13,84
Pull wellhead to surface	4,07	0,65	4,72	3,80	0,61	4,41	4,07	0,65	4,72	4,37	0,70	5,07
Bore and pin below overshot	2,07	0,33	2,40	1,80	0,29	2,09	2,07	0,33	2,40	2,37	0,38	2,75
Cut, pin and lay down sections	24,07	3,85	27,92	23,80	3,81	27,61	24,07	3,85	27,92	24,37	3,90	28,27
Secure deck openings	2,07	0,33	2,40	1,80	0,29	2,09	2,07	0,33	2,40	2,37	0,38	2,75
Risks												
NPT - WOW	3,36			3,23			3,35			3,47		
NPT - P&A risk	5,59			5,39			5,59			5,78		
Total (hours)	913,59			812,53			911,54			1017,24		
Total (days)	38,07			33,86			37,98			42,39		

A6 Simulation Results for Dream Well

Table A6.1: Detailed analysis results for Dream Well.

Name	Example Scenario (Hours)											
	Mean			P10			P50			P90		
Prepare well for P&A and cut tubing												
Events	Duration	Project Risk	Sum	Duration	Project Risk	Sum	Duration	Project Risk	Sum	Duration	Project Risk	Sum
Drift run and caliper run	6,29	1,01	7,30	5,24	0,84	6,08	6,27	1,00	7,27	7,82	1,25	9,08
Integrity logging	6,41	1,03	7,44	5,49	0,88	6,37	6,39	1,02	7,41	7,76	1,24	9,01
Kill well, bullhead cement	9,04	1,45	10,49	7,84	1,25	9,10	9,02	1,44	10,46	10,21	1,63	11,84
Install deep set bridge plug and test plug	9,03	1,45	10,48	8,03	1,29	9,32	9,01	1,44	10,46	10,01	1,60	11,61
Punch tubing above production packer	7,01	1,12	8,14	6,61	1,06	7,67	7,01	1,12	8,13	7,40	1,18	8,59
Circulate heavy fluid (tubing+annulus)	2,27	0,36	2,63	1,77	0,28	2,05	2,26	0,36	2,62	2,75	0,44	3,19
Cut tubing above the production packer	15,90	2,54	18,44	13,50	2,16	15,66	15,84	2,53	18,37	19,34	3,09	22,43
Displace annulus and tubing to kill fluid/brine	4,77	0,76	5,54	3,91	0,63	4,54	4,75	0,76	5,52	5,77	0,92	6,69
Install downhole safety valve protection sleeve	9,78	1,57	11,35	8,55	1,37	9,91	9,76	1,56	11,32	10,83	1,73	12,56
Place tubing hanger plug in production and annulus bore	16,51	2,64	19,15	15,04	2,41	17,45	16,48	2,64	19,12	17,92	2,87	20,78
Risks												
NPT - WOW	5,22			4,56			5,21			5,99		
NPT - P&A risk	8,70			7,60			8,68			9,98		
Rig up Claxton WellRaizer												
Events	Duration	Project Risk	Sum	Duration	Project Risk	Sum	Duration	Project Risk	Sum	Duration	Project Risk	Sum
Rig up Claxton WellRaizer	170,00	27,20	197,20	170,00	27,20	197,20	170,00	27,20	197,20	170,00	27,20	197,20
Risks												
NPT - WOW	10,20			10,20			10,20			10,20		
NPT - P&A risk	17,00			17,00			17,00			17,00		
Pull vertical XMT and N/U BOP												
Events	Duration	Project Risk	Sum	Duration	Project Risk	Sum	Duration	Project Risk	Sum	Duration	Project Risk	Sum
Pull vertical XMT to surface	15,55	2,49	18,04	14,15	2,26	16,41	15,52	2,48	18,00	16,91	2,71	19,61
Install BOP	17,68	2,83	20,51	15,25	2,44	17,69	17,63	2,82	20,45	20,05	3,21	23,26
Risks												
NPT - WOW	1,99			1,76			1,99			2,22		
NPT - P&A risk	3,32			2,94			3,32			3,70		
Recover Production Tubing												
Events	Duration	Project Risk	Sum	Duration	Project Risk	Sum	Duration	Project Risk	Sum	Duration	Project Risk	Sum
Pull up and run landing string	11,89	1,90	13,80	11,27	1,80	13,08	11,88	1,90	13,78	12,41	1,99	14,40
Engage to wellhead	11,89	1,90	13,80	11,27	1,80	13,08	11,88	1,90	13,78	12,41	1,99	14,40
RIH with tubing hanger retrieval tool & engage tubing hanger	1,75	0,28	2,03	1,65	0,26	1,92	1,75	0,28	2,03	1,85	0,30	2,15
Pull tubing hanger and tubing	72,83	11,65	84,49	60,00	9,60	69,60	72,53	11,60	84,13	89,27	14,28	103,55
Risks												
NPT - WOW	5,90			5,05			5,88			6,96		
NPT - P&A risk	9,84			8,42			9,80			11,60		
Cleanout and log 9 5/8" casing												
Events	Duration	Project Risk	Sum	Duration	Project Risk	Sum	Duration	Project Risk	Sum	Duration	Project Risk	Sum
Clean 9 5/8" casing	59,84	9,57	69,42	56,33	9,01	65,34	59,78	9,56	69,34	62,47	9,99	72,46
Log 9 5/8" casing	13,62	2,18	15,80	13,33	2,13	15,46	13,62	2,18	15,79	13,92	2,23	16,15
Risks												
NPT - WOW	4,41			4,18			4,40			4,58		
NPT - P&A risk	7,35			6,97			7,34			7,64		
Set reservoir plug inside 9 5/8" casing (seal 4)												
Events	Duration	Project Risk	Sum	Duration	Project Risk	Sum	Duration	Project Risk	Sum	Duration	Project Risk	Sum
Install 9 5/8" Bridge plug	25,07	4,01	29,08	23,07	3,69	26,76	25,03	4,00	29,03	27,01	4,32	31,33
Set primary reservoir plug inside 9 5/8" casing	28,22	4,51	32,73	25,66	4,11	29,77	28,16	4,51	32,67	30,78	4,93	35,71
Wait on cement and test plug	14,03	2,24	16,27	13,23	2,12	15,34	14,01	2,24	16,25	14,80	2,37	17,17
Set secondary reservoir plug inside 9 5/8" casing	28,22	4,51	32,73	25,66	4,11	29,77	28,16	4,51	32,67	30,78	4,93	35,71
Wait on cement and test plug	14,03	2,24	16,27	13,23	2,12	15,34	14,01	2,24	16,25	14,80	2,37	17,17
Risks												
NPT - WOW	6,57			6,05			6,56			7,09		
NPT - P&A risk	10,96			10,08			10,94			11,82		
Restore seal 3												
Events	Duration	Project Risk	Sum	Duration	Project Risk	Sum	Duration	Project Risk	Sum	Duration	Project Risk	Sum
Install 9 5/8" Bridge plug	17,16	2,75	19,91	16,21	2,59	18,81	17,14	2,74	19,88	18,16	2,91	21,07
Primary internal cement plug	28,22	4,51	32,73	25,66	4,11	29,77	28,16	4,51	32,67	30,78	4,93	35,71
Wait on cement and test cement plug	14,03	2,24	16,27	13,23	2,12	15,34	14,01	2,24	16,25	14,80	2,37	17,17
Secondary internal cement plug	46,05	7,37	53,42	44,65	7,14	51,79	46,02	7,36	53,38	47,41	7,59	54,99
Wait on cement and test plug	14,03	2,24	16,27	13,23	2,12	15,34	14,01	2,24	16,25	14,80	2,37	17,17
Risks												
NPT - WOW	7,17			6,78			7,16			7,56		
NPT - P&A risk	11,95			11,30			11,93			12,60		
Cut 9 5/8" casing & cleanout and log 13 3/8" casing												
Events	Duration	Project Risk	Sum	Duration	Project Risk	Sum	Duration	Project Risk	Sum	Duration	Project Risk	Sum
Cut 9 5/8" casing	12,04	1,93	13,97	10,84	1,73	12,58	12,02	1,92	13,94	13,21	2,11	15,32
RIH with casing hanger retrieval tool and engage casing hanger	3,25	0,52	3,77	3,02	0,48	3,50	3,25	0,52	3,77	3,47	0,56	4,03
Pull 9 5/8" casing	79,24	12,68	91,92	68,61	10,98	79,58	79,02	12,64	91,66	89,49	14,32	103,81
Cleanout 13 3/8" casing	9,66	1,54	11,20	9,45	1,51	10,96	9,65	1,54	11,20	9,82	1,57	11,40
Log 13 3/8" casing	5,28	0,85	6,13	5,17	0,83	5,99	5,28	0,84	6,12	5,40	0,86	6,26
Risks												
NPT - WOW	6,57			5,82			6,55			7,28		
NPT - P&A risk	10,95			9,71			10,92			12,14		
Restore seal 2												
Events	Duration	Project Risk	Sum	Duration	Project Risk	Sum	Duration	Project Risk	Sum	Duration	Project Risk	Sum
Install 13 3/8" Bridge plug	8,03	1,28	9,31	7,23	1,16	8,38	8,01	1,28	9,29	8,80	1,41	10,21
Primary internal cement plug	28,22	4,51	32,73	25,66	4,11	29,77	28,16	4,51	32,67	30,78	4,93	35,71
Wait on cement and test cement plug	14,03	2,24	16,27	13,23	2,12	15,34	14,01	2,24	16,25	14,80	2,37	17,17
Secondary internal cement plug	28,22	4,51	32,73	25,66	4,11	29,77	28,16	4,51	32,67	30,78	4,93	35,71
Wait on cement and test cement plug	14,03	2,24	16,27	13,23	2,12	15,34	14,01	2,24	16,25	14,80	2,37	17,17
Risks												
NPT - WOW	5,55			5,10			5,54			6,00		
NPT - P&A risk	9,25			8,50			9,24			10,00		
N/D BOP												
Events	Duration	Project Risk	Sum	Duration	Project Risk	Sum	Duration	Project Risk	Sum	Duration	Project Risk	Sum
N/D BOP	2,01	0,32	2,34	1,61	0,26	1,87	2,01	0,32	2,33	2,40	0,38	2,79
Risks												
NPT - WOW	0,12			0,10			0,12			0,14		
NPT - P&A risk	0,20			0,16			0,20			0,24		
Cut and pull 13 3/8" Casing												
Events	Duration	Project Risk	Sum	Duration	Project Risk	Sum	Duration	Project Risk	Sum	Duration	Project Risk	Sum
Cut 13 3/8" casing	12,04	1,20	13,25	10,84	1,08	11,93	12,02	1,20	13,22	13,21	1,32	14,53
Pull 13 3/8" casing using WellRaizer	18,47	1,85	20,32	16,03	1,60	17,63	18,42	1,84	20,26	21,09	2,11	23,20
Risks												
NPT - P&A risk	3,05			2,69			3,04			3,43		
Restore seal 1 - surface barrier												
Events	Duration	Project Risk	Sum	Duration	Project Risk	Sum	Duration	Project Risk	Sum	Duration	Project Risk	Sum
Install 20" bridge plug	5,94	0,95	6,89	5,65	0,90	6,55	5,93	0,95	6,88	6,30	1,01	7,31
Mix and pump cement	4,76	0,76	5,52	4,52	0,72	5,24	4,75	0,76	5,51	4,99	0,80	5,79
Install environmental cement plug	1,76	0,28	2,04	1,50	0,24	1,74	1,75	0,28	2,03	2,01	0,32	2,33
Wait on cement	6,32	1,01	7,33	4,42	0,71	5,13	6,28	1,01	7,29	8,33	1,33	9,66
Verify surface plug	3,31	0,53	3,84	2,61	0,42	3,03	3,30	0,53	3,82	3,99	0,64	4,63
Risks												
NPT - WOW	1,33			1,12			1,32			1,54		
NPT - P&A risk	2,21			1,87			2,20			2,56		
Cut casing and conductor												
Events	Duration	Project Risk	Sum	Duration	Project Risk	Sum	Duration	Project Risk	Sum	Duration	Project Risk	Sum
Drill and pin conductor	0,69	0,11	0,80	0,60	0,10	0,69	0,68	0,11	0,79	0,79	0,13	0,91
Cut casings and conductor	17,53	2,80	20,33	16,31	2,61	18,92	17,50	2,80	20,30	18,71	2,99	21,70
Risks												
NPT - WOW	1,09			1,01			1,09			1,17		
NPT - P&A risk	1,82			1,69			1,82			1,95		
Retrieve wellhead, surface casing and conductor												
Events	Duration	Project Risk	Sum	Duration	Project Risk	Sum	Duration	Project Risk	Sum	Duration	Project Risk	Sum
Pull up and run landing string	11,89	1,90	13,80	11,27	1,80	13,08	11,88	1,90	13,78	12,41	1,99	14,40
Engage to wellhead and conductor	11,75	1,88	13,63	11,41	1,83	13,23	11,74	1,88	13,62	11,93	1,91	13,84
Pull wellhead to surface	4,07	0,65	4,73	3,80	0,61	4,41	4,07	0,65	4,72	4,38	0,70	5,08
Bore and pin below overshot	2,07	0,33	2,41	1,80	0,29	2,09	2,07	0,33	2,40	2,38	0,38	2,76
Cut, pin and lay down sections	24,07	3,85	27,93	23,80	3,81	27,61	24,07	3,85	27,92	24,38	3,90	28,28
Secure deck openings	2,07	0,33	2,41	1,80	0,29	2,09	2,07	0,33	2,40	2,38	0,38	2,76
Risks												
NPT - WOW	3,36			3,23			3,35			3,47		
NPT - P&A risk	5,59			5,39			5,59			5,79		
Total (hours)	**1183,56**			**1092,42**			**1181,59**			**1278,93**		
Total (days)	**49,31**			**45,52**			**49,23**			**53,29**		