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Cost Analysis of Plug and Abandonment Operations on the Norwegian Continental Shelf

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Problem Description

Plug and abandonment (P&A) is the process of installing permanent or temporary barriers to seal a well or a section of a well to prevent flow between different formations or hydrocarbons to the surface of the well. In the same way as the Norwegian state takes 78% of petroleum revenues in tax, it must also bear an equally large share of the costs involved in activities such as P&A of wells. This means that the government will have to bear the greater part of the P&A related costs. With high costs and low availability on resources to perform the P&A operations, there is a need for making the process of P&A as cost-efficient as possible.

The thesis will include the following:

- Developing mathematical models to estimate total P&A costs on the NCS, finding optimal shut down times, and coordination of resources to perform P&A operations.
- Investigation of the main cost drivers for P&A operations.
- Discussion on what kind of mathematical models can be used to solve different problems in different planning levels.
- Implementation of the models in appropriate optimisation software.
- Sensitivity analyses to investigate the effects of changes in prices, durations and multi-well campaigns.

Preface

This thesis is the concluding part of my Master of Science degree in Industrial Economics and Technology Management at the Norwegian University of Science and Technology (NTNU). The thesis was written in Trondheim, Norway during the period January 2016 - June 2016. I would like to thank my academic supervisor Asgeir Tomasgaard at the Department of Industrial Economics and Technology Management (IØT) at NTNU for helpful guidance throughout the course of writing this thesis.

A special thanks is brought to researchers at the department of Applied Economics at SINTEF Technology and Society for inputs on modelling and structure of the thesis. In particular, I would like to thank Kjetil Trovik Midthun, for continuous help and support throughout this work. For insights on the field of plug and abandonment of wellbores, I would like to thank Velaug Myrseth Oltedal and Malin Torsæter at SINTEF Petroleum, and for real options theory, a thanks is brought to Verena Hagspiel at NTNU, who has given me valuable insights on the subject. I also would like to thank Rystad Energy for forecast data on petroleum production and costs. All help and contributions have been highly appreciated.

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Abstract

Norway is one of the world's largest petroleum exporters and has been producing oil and gas for almost 50 years. Many of the petroleum fields are soon reaching their maturity stage where income cannot cover the expenses, and must shut down production. In this process, all associated wells are required to be plugged and abandoned. These operations are expensive, and there is a need for conducting targeted research aimed at reducing the costs associated with plug and abandonment (P&A).

In this thesis we consider 82 currently producing fields and 3308 wellbores on the Norwegian Continental Shelf (NCS). A categorisation of these wellbores was performed by using publicly available information on wellbore statuses in combination with a method for determining the required remaining P&A operations. This information was used to estimate the total costs related to P&A operations for each petroleum field on the NCS. The categorisation, cost estimate and information on forecast production and expenses, formed the basis for the development of three optimisation models and one real options model aimed at conducting cost and planning analyses of P&A operations.

We address this cost analysis of P&A operations holistically by focusing on three different planning levels: strategic, tactical and operational. Our study shows that P&A costs should be included when planning for shut downs and that in general there are incentives for postponing shut downs both due to discount rate benefits and uncertainty in petroleum prices. In addition, we found that collaboration in the planning of multi-well P&A campaigns might be economic desirable compared to planning for these operations for fields and wells independently.

This thesis' main contribution is the development of optimisation models that can be used for several purposes associated with P&A, a subject that up to this point is at best scarcely covered in current literature. We believe that the models could be a good starting point for robust cost analysis and planning tools relevant for different actors in the Norwegian petroleum industry.

Sammendrag

Norge er en av verdens største petroleumseksportører og har produsert olje og gass i nesten 50 år. En stor del av feltene på norsk sokkel nærmer seg avslutningsfasen hvor innektene fra produksjon ikke lenger kan dekke kostnadene, og må stenge ned driften. I forbindelse med dette må alle tilhørende brønner plugges of forlates (P&A). Dette er svært kostbart, og det er behov for målrettet forskning knyttet til reduksjon av disse kostnadene.

Denne masteroppgaven tar for seg 82 produserende felt og 3308 brønnbaner på den norske kontinentalsokkel. Vi gjennomførte en kategorisering av disse brønnbanene ved å bruke offentlig tilgjengelig informasjon om brønnbanenes status kombinert med metoder for å avgjøre hvor mye gjenværende P&A-relatert arbeid som kreves. Dette ble brukt til å estimere totale kostnader av P&A-operasjoner for hvert felt på sokkelen. Kategoriseringen, kostnadsestimatet, og produksjons- og kostnadsprognoser dannet grunnlaget for utviklingen av tre optimeringsmodeller og en realopsjonsmodell med sikte på å gjennomføre kostnads- og planleggingsanalyser av P&A-operasjoner.

Vi angriper denne kostnadsanalysen av P&A-operasjoner holistisk ved å fokusere på tre planleggingsnivåer: strategisk, taktisk, og operasjonelt. Våre analyser viser at P&A-kostnader bør inkluderes når man planlegger for nedstenging av felt og at det generelt er insentiver for å utsette nedstenging både på grunn av diskontering av kontantstrømmer og usikkerhet i oljepris. I tillegg konkluderer vi med at samordning i planlegging av P&A-operasjoner kan resultere i store kostnadsbesparelser sammenlignet med å planlegge P&A for hver enkelt felt og brønn individuelt.

Vårt hovedbidrag er utviklingen av optimeringsmodeller som kan brukes til flere typer analyser knyttet til P&A, et område som til nå ikke er godt dekket i litteraturen. Vi mener at modellene kan være et godt utgangspunkt for gode kostnads- og planleggingsvertøy som kan være relevant for flere aktører i norsk petroleumsindustri.

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Chapter 1

Introduction

This thesis is part of the project "Economic Analysis of Coordinated Plug and Abandonment Operations" (ECOPA) funded by the Research Council of Norway. The aim of the project is to gather available data relevant for P&A operations on the Norwegian Continental Shelf (NCS) and to develop and use a plug and abandonment (P&A) planning software to derive P&A costs in various scenarios.

P&A is the activity of closing a well for production and is conducted to avoid contamination of the environment outside the well and avoid cross-contamination of inflow sources in the well, as well as preventing leaks in and out of the well. This must be performed on each well when a field is shut down and decommisioned. Earlier estimates have concluded that the total costs related to P&A operations can reach the order of magnitude of hundred of billions USD in the next 40 years, counting wells to be established in this period. It is therefore necessary to conduct targeted research and development regarding new technology and planning of operations in order to reduce expenses associated with P&A.

This thesis is an early contribution to the ECOPA project, where we develop mathematical models based on optimisation and real options theory in order to address some of the issues mentioned above. The models developed in this thesis have three main objectives: (1) investigation of optimal shut down time of fields on the NCS, (2) optimal allocation of resources to perform P&A operations on a 3-5 year time horizon, and (3) obtaining optimal day-to-day schedules for resources in a P&A campaign. In addition, a method for gathering relevant information on well statuses and P&A requirement of all current development wells and calculating total costs of P&A operations is presented. Mathematical programming (MP) has been widely used in the petroleum industry, but no specific use of MP directly related to P&A has been observed. Other contributions to the field of P&A and shut down of fields make use of statistical methods, simulation and real options theory.

The numerical results presented in this thesis should be interpreted as approximates and estimates. When fictitious parameters are used to obtain results, we specify this and suggest that the reader focus on the application area of the models rather than the numerical results. We believe that the models and approaches developed in this thesis will serve as a starting point for obtaining some of the goals of the ECOPA project and provide contributions to a subject that is not well covered in literature yet. In Section 1.1, we present the research questions and objectives to which this thesis will provide answers. In Section 1.2, we describe the different planning levels that lay the main basis of the structure of the thesis. Then, in Section 1.3 and 1.4, we demarcate the scope of this thesis and present the structure of the remainder of this report, respectively.

1.1 Research Questions

This thesis will try and answer the following research questions and objectives. We will revisit these when presenting the different models.

- How much P&A work is required for current development wells on the NCS?
- What are the estimated total costs of P&A activities on the NCS for current producing fields?
- When is the optimal time for shut down of fields on the NCS?
- How does uncertainty in oil prices influence the decision to shut down?
- How should P&A operations of wells be planned in order to obtain the most efficient use of resources?
- What are the effects of operators cooperating in the planning and execution of P&A activities?
- How can different optimisation models provide answers to these questions? This is our main contribution.

1.2 Planning Levels

In supply chain management (SCM) literature, it is common to classify planning decisions into three different levels, normally based on the decision's effects on an organisation, the planning frequency, and the planning horizon (Gunasekaran et al., 2004; Stadtler and Kilger, 2008). These decisions are often classified as follows:

- **The Strategic Level**: Decisions with long-lasting effects. Relatively low planning frequency and long planning horizon.
- **The Tactical Level**: Decisions with medium planning frequency, at least once a year, and planning horizon from months to years.
- **The Operational Level**: Day-to-day decisions. High planning frequency and short time horizon (Simchi-Levi et al., 2004).

Although such classification enables a certain demarcation of the level of decisions to be made, it is important to consider the interlink between them (Ivanov, 2010). Our high level cost estimation and investigating whether a field should be shut down or not in a long time horizon fits the strategic level. The allocation of resources to P&A operations over a medium time horizon (1-5 years) can be categorised as tactical level decisions. Obtaining a day-to-day shcedule for P&A operations fits the operational level.

1.3 Scope and Assumptions

It is important to demarcate the scope and present assumptions that are valid throughout the entire thesis.

We are investigating only development wells that has not been plugged and abandoned (P&A'ed) yet. Exploration wells are excluded as they are normally being P&A'ed immediately after sufficient data has been retrieved. Future wells are omitted, as information on these does not exist[1].

When we perform the high level costs estimate of required P&A operations on the NCS, we are focusing on the duration required for the actual operations performed in the wells, and attaching costs to these durations. This means that we are excluding any costs regarding mobilisation and demobilisation of vessels and mobile rigs and other costs associated with decommissioning of installations.

[1] NPD reports some wells that is categorised as planned for development and operation approved (PDO)-approved. These are also excluded as those wells may not be drilled

Also, we exclude taking into consideration idle time and transport time. However, we include an average wait on weather (WOW) factor of 20% and an average non-productive time of 20%, based on earlier cost estimates in literature. On the operational level, we include mobilisation cost and travel durations. All durations and vessel rental rates are based on Spieler and Øia (2015), and is given in Appendix A.

The strategic model is only considering shut down of fields that are listed in the NPD's database. In reality, some fields may comprise several independent installations that has been established in different decades. Some of these installations has been shut down, some are barely not producing, and some will continue to produce in decades to come. Since we have not been able to gather information on production levels and expenses on an installation level, we only consider shut down of fields. Therefore, for some of the fields analysed in this thesis, the results would be unrealistic. This assumption is valid for the tactical and operational level as well.

All numbers related to economics are before taxes. Since the marginal tax rate on profits for petroleum companies on the NCS is the same as the tax deduction on P&A operations, we omit tax considerations. However, we will comment on the required government spending when presenting the cost estimate.

We assume that all wells that are attached to platforms do not need mobile vessel to perform P&A operations. Mobile vessels are only considered for subsea wells. Further, we are considering only three different types of vessels. When estimating total costs, we assume that the share of technologies used for setting permanent plugs are fixed. These assumptions are in accordance with assumptions made by Spieler and Øia (2015).

The terms "wellbore" and "well" refer to different installations. When there is no reason to distinguish between them, we use the term "well", but when the discussion becomes detailed around the constituents of a well, we use both terms. We distinguish between the terms temporary plug and abandonment (TP&A) and permanent plug and abandonment (PP&A) when both are relevant. When only considering PP&A, as in the tactical and operational level, as well as when we speak of total costs related to the operations, we use the term plug and abandonment (P&A).

Fields on the NCS are producing both crude oil, gas, natural gas liquids (NGL) and condensate. The latter is not included in the thesis, as data collection was only made for the three former. This is not crucial, as the production of condensate is very low compared to the other products.

In Chapter 2, we present a framework for cost estimation that includes different complexities of the work needed to execute each phase in a P&A process. In this thesis, we do not consider different complexities as such information about wells are not obtainable.

1.4 Structure of Thesis

The remainder of the master thesis is structured as follows:

Chapter 2 defines the P&A procedure, provides a summary regarding regulations associated P&A, presents previous analyses on the P&A situation on the NCS, and provides a discussion regarding influencing factors on P&A decisions. In addition, a cost estimation framework is presented. In Chapter 3, a review of relevant literature is given, along with relevant general optimisation problems that were used as inspiration for some of the models developed. Chapter 4 explains the methods used to achieve the data and other necessary information. Chapter 5 presents the results from the cost estimation and data processing regarding remaining required P&A work on the NCS. Chapter 6 presents the optimisation models used in the strategic, tactical and operational level. A real options model is also presented. We also present a possible approach for forecasting petroleum production on a well level. Chapter 7 presents all results for different cases of the strategic optimisation model together with relevant discussions. Results from the real options model is also included here. Chapter 8 contains results from the tactical model runs for different cases and discussion on improvements of the model. Chapter 9 presents the results from running the operational model. Chapter 10 contains different sensitivity analyses for the different models presented in Chapter 6. Chapter 11 provides a discussion on the inter-dependencies of the models and challenges related to decomposing the problem into different levels. Also, a discussion regarding the approaches' and models' relevance for industry actors is given. Chapter 12 concludes the thesis with main findings and suggestions for further research.

Chapter 2

Background

In this Chapter, we give a short introduction to petroleum production on the NCS in Section 2.1. Then, in Section 2.2 we define P&A and the main constituents of the P&A procedure. A short introduction to the P&A situation today is given in Section 2.3, and in Section 2.4, we cover some challenges associated with P&A. A summary of the most important regulations and requirements concerning P&A is given in 2.5. Finally, in Section 2.6 a framework developed by Oil and Gas UK (2015) is presented, to give insights on how cost estimation of P&A activities of wells and fields often are conducted by industry actors. A discussion on net present value (NPV) considerations is also presented here.

2.1 Field Production on the NCS

According to Norsk Petroleum, only 47% of the total recoverable resources on the NCS has been produced and sold the last 50 years. Both Norsk Petroleum and data obtained from the UCube database from Rystad Energy suggest that the production of oil and gas on the NCS will remain high for the next 50 years (Norsk Petroleum, 2016a; Rystad Energy, 2016). Figure 2.1 shows historic and expected oil and gas production in the period 1969-2100, retrieved from Rystad Energy (2016).

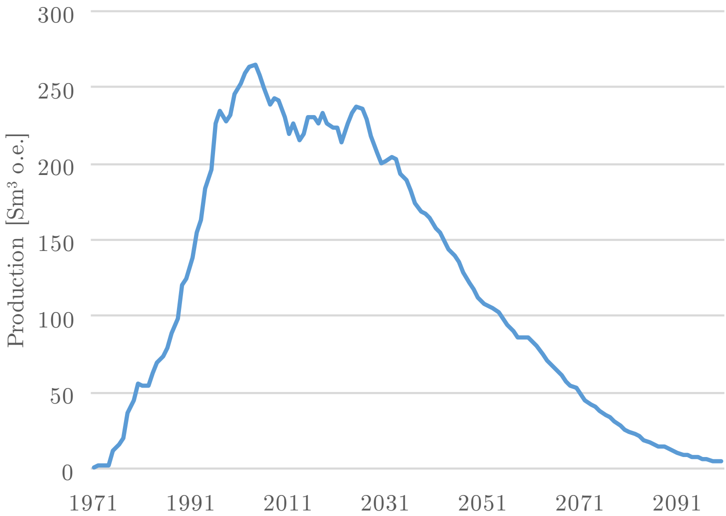

Figure 2.1: Historic and forecast aggregated production of crude Oil, NGL, and gas on the NCS (Rystad Energy, 2016). $Sm^3o.e.$ = Standard cubic metres oil equivalents.

The typical production in an oil field passes several stages and can be illustrated by a production profile. An idealised version of such production profile is presented conceptually in Figure 2.2. Most of the petroleum fields on the NCS bear resemblance to the idealised production profile, and is deemed as a good representation of the stages an oil field passes through. When comparing Figure 2.2 and Figure 2.1, we can clearly see that this is the case at least on the aggregated level.

After the discovery well, an appraisal well is drilled in order to determine the development potential of the reservoir. Then, the first production well or wells are drilled, and starts the build-up phase. After a certain point in time, the field reaches a plateau, where production rate is held steady for a while, before a new phase of decline in production is reached. Finally, when a point denoted the economic limit[1] is reached, abandonment is performed. The plateau phase are typically long for large fields, while for small fields it is sometimes represented by a peak. There can be many reasons for decline in production, including politics, malfunctioning, sabotage and depletion. Usually, the decline is driven by some combination of these factors (Höök, 2009).

[1] In literature, the economic limit is defined as the point where income from production cannot cover expenses (Mian, 1992).

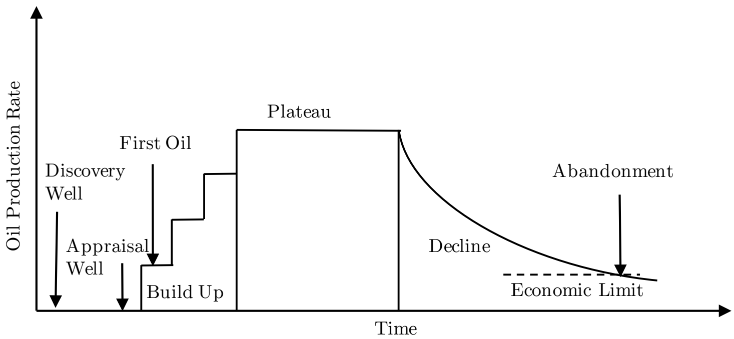

Figure 2.2: A theoretical production profile, describing the various stages of maturity of a petroleum field (Höök, 2009).

2.2 Plug and Abandonment Definition

An active petroleum well can serve three different purposes: (1) exploration - looking for oil and gas, (2) production - producing oil and gas, (3) injection - injection of fluids to maintain reservoir pressure with the aim of increasing and/or maintaining production levels. All wells have in common that, at some point in time, they must be plugged and abandoned (P&A'ed). P&A is the operation of closing a well for production and is conducted to avoid contamination of the environment outside the well and avoid cross-contamination of inflow sources in the well, as well as preventing leaks in and out of the well. The area in which the well has been installed shall be left with no traces of drilling and well activities (Handal, 2014).

The cost of extracting oil and gas will at some point exceed the income from selling the products. The operator can then choose between several options: (1) If production from the reservoir is profitable from another wellbore than the original, the operator may plug the initial wellbore and extract oil and gas profitably through the new wellbore. This is called slot recovery (the wellbores used for slot recovery is often called a sidetrack). If slot recovery is not an option, the operator can either (2) temporarily or (3) permanently P&A the well (TP&A or PP&A, respectively). The former is chosen if the operator intends to resume production at a later time or postpone PP&A, and the latter is chosen if the intention is to never re-enter the well (Standard Norge, 2013).

As each well is unique in nature, the PP&A operations required for wells are not a standardised procedure. However, most of the wells need to go through the steps illustrated in Figure 2.3. These steps require different technology and resources

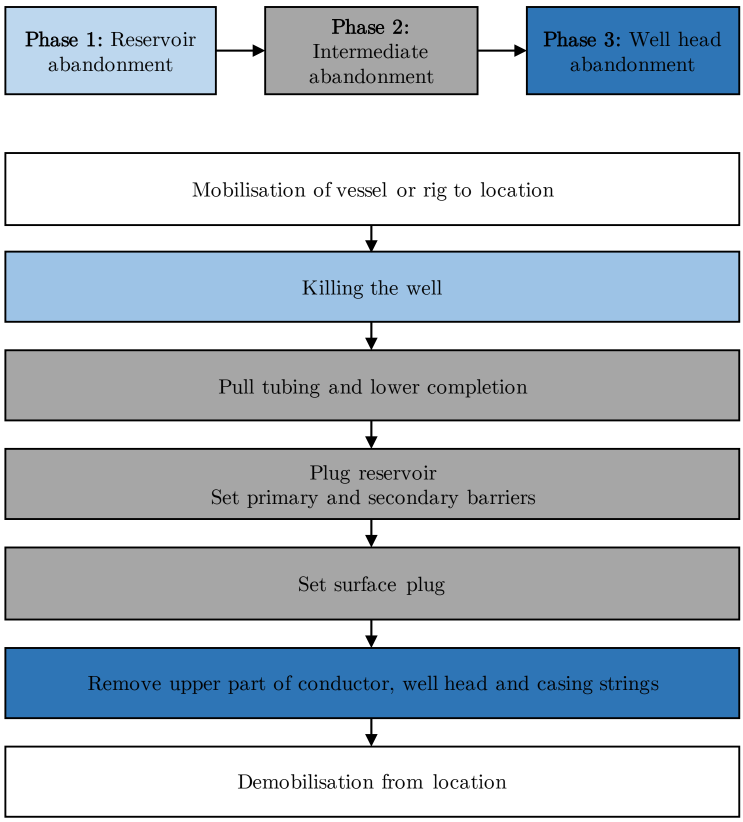

Figure 2.3: Flowchart describing the PP&A operations

and the execution times for each phase are individual for each well. It is difficult to estimate the time required, as unforeseen events such as harsh weather, well conditions, and other factors will impact the execution of the steps (see Section 2.4.3).

The choice of methods for intermediate abandonment rely on several factors for each well. We will not go into detail, but briefly explain three methods that we will revisit later when we perform the cost estimation. For the intermediate abandonment, i.e. phase 2, we assume three different methods for setting permanent barriers: setting internal cement plug (ICP), section milling (SM) and perforate, wash and cement (PWC). We refer to Spieler and Øia (2015) for a detailed description of these methods. We assume that the distribution of technologies used for this phase for both subsea and platform wells are fixed (40%, 25% and 35%, respectively).

When presenting the tactical and operational model and related result, we split phase 2 into two for subsea wells, because we allow the setting of surface plug to be performed by several vessels. We will use phase 1, 2, 3, 4 for subsea wellbores and 1, 2, 4 for platform wellbores. Further we assume that for subsea wells, phase 1 must be performed by a riserless light weight intervention vessel (RLWI), phase 2 by a mobile offshore drilling unit (MODU), phase 3 by MODU or RLWI and phase 4 by RLWI or by a light construction vessel (LCV). For platform wells, we assume that all P&A operations are performed from the existing platform and thus do not need mobile resources to execute the required processes. These assumptions are based on (Spieler and Øia, 2015).

According to the Norwegian Petroleum Directorate, PP&A of wells is normally conducted if the field and/or installations in which the wells are located are not economically profitable anymore. This means that if certain wells are not contributing to the profits, they are TP&A'ed until the total field/installation is not economically viable. Then, all wells are PP&A'ed and the field or installation is shut down from production. Some wells are TP&A'ed because they are assessed as potential slots for further development of the reservoir.

A well can be TP&A'ed with or without monitoring. If a well is TP&A'ed without monitoring, there is a time limit of three years before either reopening or PP&A must be conducted. If the operator choose to continuously monitor the well to ensure integrity, the time limit is in practice infinite (Standard Norge, 2013).

2.3 P&A Situation on the NCS

In April 2016, a total of 5839 wellbores had been drilled on the NCS. Of these (dependent on how one counts), 4383 (or 75%) are development wellbores, i.e. production, injection and observation wells. Of these, approximately 215 has status "P&A" or "Junked" (we will come back to these statuses in Chapter 4), meaning that over 4000 wellbores must be P&A'ed in the future (we will operate with a lower number, as we exclude some wellbores in our analysis). Despite the fact that the oil industry are facing times with lower activity due to increased supply and reduced demand of petroleum products and thus reduced prices, there is reason to believe that new wells will be drilled in the future to remain a certain supply level based on forecast production in for instance the Barents Sea.

In Statoil's estimates from 2013 on the time 15 rigs need to P&A 3000 wellbores, they use an average P&A time per wellbore of 35 days, giving the total time needed for 15 rigs operating without breakdowns or idle time of 20 years. Further, they include an estimation of the number of new development wellbores during this period of 20 years to 2880 wellbores. Thus, in order to P&A all these wellbores, both current and future development wellbores, the rough estimate concludes with a need for 15 rigs on full time for P&A in 40 years (Statoil, 2014). Statoil claims that the NCS is in general short on rigs. The rigs are also used for other purposes, such as drilling new development wells. This suggests that 40 years might be an underestimation, and that if the demand for rigs are increasing due to new development wells, the daily costs might increase.

On the NCS, the operator is responsible for bearing all the costs associated with P&A operations, including any cleanup costs resulting from leakage (Liversidge et al., 2006). The petroleum taxation system in Norway is based on the rules for ordinary company taxation and are set out in the Petroleum Taxation Act (Act of 13 June 1975 No. 35). In addition to ordinary company tax rate of 25%, the oil companies are subject to an additional special tax of 53%. Therefore, the marginal tax rate is 78%. The Norwegian government thus receives the majority of the income from oil companies (in 2008, at its highest point, the total tax revenue from oil companies was over 34 billion USD) (Norsk Petroleum, 2016b). The petroleum taxation system is neutral, meaning that only the operator's net profit is taxable. The cost of P&A is tax deductible at the same tax rate, 78%. According to Statoil's estimation, the oil industry can deduce 82 billion USD in taxes as a result. Indirectly, these costs can be interpreted as an expense for the government, and ultimately an expense paid by the Norwegian tax payers.

2.4 Challenges with P&A

There are many challenges associated with P&A, both regarding technology, planning, and uncertainty. This section will discuss some of these factors, and try to explain in short terms how these challenges impact the total cost and execution of P&A operations.

2.4.1 Technology

One of the main challenges associated with how P&A is conducted today is the technology used to perform the operations. Since the beginning of petroleum production on the NCS, only a few wells have been P&A'ed, and technology has not matured to a level such that operations can be performed in a time and cost optimal manner. Oil companies such as Statoil are focusing on developing new technology that will contribute to more efficient P&A operations in the future, e.g. technology for faster casing removal, alternative methods and materials for creating annulus barriers, P&A without cutting and pulling casing and tubing, and opportunities of P&A of subsea wells by using vessels instead of rigs (Statoil, 2012).

In Moeinikia et al. (2014), they find that using RLWI for some of the sub-operations of P&A of subsea wells will release rig time for drilling and completing new oil wells, and result in lower total cost of P&A as the rental rate of RLWIs is lower than for rigs. Statoil claims that a 30% cost saving as a result of technology development where rigless P&A operations replaces rig-based is realistic. Revisiting the example presented in Section 2.3, this could mean a reduction of the government's bill by 25 billion USD. Based on these estimates, it is safe to conclude that if the technology develops, there are significant gains to accomplish.

2.4.2 Planning

As mentioned in Section 2.3, the operator is responsible for all P&A costs. According to a Swedish oil company, the general attitude of operators is that P&A operations are postponed as much as possible in order to take advantage of cost saving possibilities due to multi-well campaigns and the fact that costs later in time is lower than costs in the present due to discount rate effects. However, they predicted that a major challenge associated with postponing operations is that at a certain point in time, when the wells ultimately has to be P&A'ed, the pressure on resources needed to conduct all operations will be considerably high. This might lead to high rental costs of rigs, vessels, and other resources due to increased demand, and coordination problems. They suggest that, in order to save costs and obtain valuable knowledge and experience on P&A operations, companies should P&A the wells as soon as they become candidates for P&A, not wait on possible multi-well campaigns. This way, they believe that the pressure on future resource usage can be reduced, and that operations will be conducted more efficiently as operators have gained experience. Also, they suggest that one should take advantage of the oil price being at a very low level, as rental rates is positively correlated with oil price.

2.4.3 Uncertainty

The discussions and examples provided up to this point has not taken into account uncertainty related to P&A operations. Moeinikia et al. (2014) present an overview of the typical unexpected events that can impact the duration and cost of a P&A operation on a single well. This list is presented in Appendix B. It does not include all possible events that might occur, but serves as an example of what can cause problems. In addition to these possible events, wait on weather (WOW) is a major determinant for the duration of a P&A operation. Some operators consider an extra duration of 10-15% of standard operating time due to WOW. In the winter, some operators on the NCS consider as much as 50% of the total time being related to WOW. This consideration could be included in modelling the duration of P&A. All unexpected events will result in high uncertainty of durations of P&A operations. In this thesis however, we are assuming deterministic durations.

Other uncertain factors that affect the production decisions include uncertainty in petroleum prices, remaining recoverable resources in a reservoir, defects on wells and equipment, policy changes, etc. In this thesis, we will handle only changes in oil prices on the strategic planning level in our real options approach as uncertain factor, based on the hypothesis that uncertain oil prices might give incentives for postponing shut down of fields.

2.5 Regulations

All operations, including P&A operations on the NCS are mainly regulated by the Norwegian petroleum act (OSPAR) and NORSOK Standards (D-010 rev. 4 August 2013 in particular). NORSOK D-010 focus on well integrity by defining the minimum functional and performance oriented requirements and guidelines for well design, planning and execution of well operations in Norway.

Chapter 9 in NORSOK D-010 covers requirements and guidelines related to well integrity during P&A of a well. In Section 9.3, Well barrier acceptance criteria are presented, including amongst other a description of functions and types of different well barriers and the positioning of the barriers, and requirements regarding materials, leak testing and sidetracking. Sections related to requirements for both TP&A and PP&A are also included here. Section 9.4, 9.5 and 9.6 give further guides on more specific requirements of the P&A operations (Standard Norge, 2013).

Between two an five years prior to an installation or field ceasing production, operators are required to submit a decommissioning plan, including an Environmental Impact Assessment and plans for public consultation. The Norwegian Ministry of Petroleum and Energy makes the final decision on decommissioning in consultation with the Norwegian Petroleum Directorate (NPD) (Oil and Gas UK, 2016).

2.6 Cost Estimation Framework and Net Present Value

In this section, a categorisation framework for wells and P&A operations from Oil and Gas UK (2015) is presented. This categorisation is used to estimate the total time and costs of P&A activities by many industry actors, both worldwide and in Norway. Parts of the framework is used when estimating total cost of P&A operations.

The guideline presents a P&A code that is used to represent the location of the well and the work complexity of each of the three phases that must be completed before P&A of a well is complete. The guideline's definition of phases is similar to the ones showed in Figure 2.3.

- **Abandonment Phase 1 - Reservoir abandonment**: Reservoir producing or injecting zones are isolated by primary and secondary barriers. The tubing may be left in well, or retrieved partly or completely.
- **Abandonment Phase 2 - Intermediate abandonment**: The setting of barriers to intermediate hydrocarbon or water-bearing permeable zones. Also involves isolation of liners and milling, as well as retrievement of casing.
- **Abandonment Phase 3 - Wellhead and conductor removal**: Includes retrieval of wellhead, conductor, shallow cuts of casing string, and cement filling of craters.

Each of the phases are associated with a digit signifying the complexity of the work required in that phase on a certain well.

- **Type 0 - No work required**
- **Type 1 - Simple rigless abandonment**
- **Type 2 - Complex rigless abandonment**
- **Type 3 - Simple rig-based abandonment**
- **Type 4 - Complex rig-based abandonment**

Combining locations, phases and complexities in a diagram enables visualisation of the P&A code for one or several wells. It also enables an ordered assignment of duration and cost estimates for well type-phase-complexity combinations. Figure 2.4 illustrate a classification of a single subsea well.

Subsea well			Abandonment complexity				
			0	1	2	3	4
Phase	1	Reservoir abandonment		x			
	2	Intermediate abandonment				x	
	3	Wellhead conductor removal				x	

Figure 2.4: Example classification of a well according to abandonment phases and their complexities (Oil and Gas UK, 2015).

When the wells have been classified in phases, types and complexities, one can obtain the total costs by performing the calculations in a systematic way by attaching costs related to durations and resource requirements for each phase-complexity combination and adding additional costs such as mobilisation of resources and well inspections.

When considering cash flows on a long time horizon, it is important to include net present value (NPV) considerations. The net present value of a project is today's value of future incoming and outgoing cash flows associated with that project. The formula for NPV is given in Equation (2.6.1).

$$NPV = \sum_{t=0}^{N} \frac{R_t}{(1+i)^t} \tag{2.6.1}$$

Where:

- t is the time period the cash flow incurs, $t = 0$ signifies the present.
- N is the number of periods.
- R_t is the sum of the value of the cash flows incurring at time t.
- i is the discount rate/opportunity cost of capital.

From Equation (2.6.1), it is clear that an inflow today is worth more than the same inflow in the future. The rationale behind this is that the present cash flow could be invested in capital and may gain return on investment (ROI), while the same cash flow in the future may not. The same principle applies to costs. An outflow of money in the future is lower in the present because an outflow today reduces the size of a potential ROI in the future. Keeping this in mind, it is expected that if a decision maker is able to determine within a time window when inflows and outflows should be incurred, she would choose to receive as much inflow as possible early in the project period, and delay outflows as much as possible.

An apparent advantage with NPV is that it enables the inclusion of the time value of money in economic analyses, such that more realistic decisions can be taken. In estimating the income of petroleum production and the costs of P&A over a time horizon of decades and with cash flows in the magnitude of millions USD, NPV considerations becomes important. A disadvantage with NPV is the potential for poor estimation of the discount factor i, that may lead to wrong estimates. The reasons for poor estimation of i can be many, including poor risk adjustments of future rates.

Chapter 3

Literature Review

To our best knowledge, literature on mathematical programming (MP) in the field of P&A and shut down decisions are at best scarce. However, other approaches have been used in order to address issues related to P&A.

In Section 3.1 a review of use of optimisation in relevant industries is presented. Then we cover relevant literature on cost estimation and P&A duration reduction in Section 3.2. In Section 3.3 we discuss some approaches on how to calculate optimal shut down times, including a short review on relevant real options theory. We present general relevant optimisation models in Section 3.4 and provide a discussion on this thesis' position in an academic context in Section 3.5.

3.1 Optimisation in Relevant Industries

According to Williams (2013), the petroleum industry is the largest user of linear programming (LP). The decisions for which LP in petroleum industry is used include for instance where and how to buy and transport crude oil, and which products to make out of it. In Bodington and Baker (1990), the authors present the history of MP in the petroleum industry, from the invention in the 1940s until 1990, and discuss how computer technology development during these years has enabled the use of MP for more detailed planning purposes.

Haugland et al. (1988) present generic models for early evaluation of a petroleum field, including models aimed at finding production profiles and optimal location of wells. Only decisions in early field evaluation are considered.

Nygreen et al. (1998) developed a multi-period mixed integer linear programming (MILP) model used by the NPD and Norwegian operators on the NCS for long-term planning of petroleum production and transportation. The model has been used for decades, and it is still in use today (several modifications have been done since the first model). The authors assumes a production profile inside which production of oil and gas can vary.

Persson (2002) presents a MILP model that addresses the issue of choosing different run-modes for processing units in a given point in time for a refinery in Sweden. In Göthe-Lundgren et al. (2002), an optimisation model aimed at planning and scheduling for a oil refinery company is developed. A MILP model is presented where the objective is to minimise total production scheduling costs.

Ulstein et al. (2007) develop a model for tactical planning of Norwegian petroleum production that maximises profit for oil fields in the Norwegian sector. They include regulation of production levels, splitting production flows into oil and gas and transportation of the products.

In Christiansen and Nygreen (1993) a planning model for wells in the North Sea is given, where the aim is to form bases for decisions regarding which wells to produce from and which to shut down for a period. The objective function consists of maximising the profits of the operators connected to the Ekofisk field.

The problem of allocating resources such as vessels to perform P&A operations bear resemblance to ship routing and scheduling problems. In Christiansen and Fagerholt (2014), the authors develop different MILP formulations where the aim is to schedule ships in a pick-up and delivery problem. Christiansen (1999) presents a combined inventory management and routing problem with time windows related to shipment of ammonia for a Norwegian company, where they use Dantzig-Wolfe decomposition where ship routing and inventory management subproblems are created. The decomposition of vessel scheduling problems is not a new feature in literature, however. In Appelgren (1969), a column generation algorithm is developed to address this problem. Some fractional values were obtained, which was handled by cutting plane and branch and bound algorithm in Appelgren (1971).

Although these sources are not directly related to P&A, many of the principles are relevant. For instance, the model presented in Nygreen et al. (1998) has inspired us in modelling of the strategic model.

3.2 Cost of P&A Operations

In Kaiser and Liu (2014), two different approaches to cost estimation of decommissioning activities for a set of deep-water fixed platforms on the Gulf of Mexico is presented: (1) A top-down approach that uses historical data from similar activities to estimate the costs of current projects by use of statistical methods, including regression models, and (2) a bottom-up approach where project tasks are broken into smaller discrete projects where cost of each sub-project is estimated and added together to obtain the overall cost estimate. In Kaiser (2006), regression models are developed to estimate the cost of P&A activities also in the Gulf of Mexico, and the impact of learning and scale economics are examined. A similar approach is presented in Kaiser and Dodson (2007).

Spieler and Øia (2015) provide an overview of the potential expenditures that operators and the Norwegian government would face given that all wells on the NCS were to be PP&A'ed. By categorising wells, P&A techniques, durations (including non productive time and WOW), they are able to roughly estimate the cost of P&A of each well type divided in minimum, most likely, and maximum costs. Multiplying these with the appropriate well types and aggregating gives the total costs of P&A on the NCS. Analyses on potential savings on subsea wells with new technology and time duration estimates are also conducted.

Byrd et al. (2014) investigate the cost of decommissioning of a typical offshore facility by breaking down the constituents of the activity in smaller parts and adding the associated cost to obtain an estimate of total costs. They mention costs related to P&A, but does not explicitly perform calculations or present models with the purpose of estimating cost for such activities.

Raksagati (2012) uses Monte Carlo simulation in order to forecast the cost and duration of different P&A methods. Based on the findings, they recommend that the use of vessels to perform P&A operations in stead of rigs is desirable in order to free rigs for performing drilling and completion of exploration and development wells. Also, they promote P&A of several wells in a multi-well campaign in order to reduce the P&A cost on each well, and suggest cooperation between operators to reduce the total costs.

Moeinikia et al. (2014) also use a Monte Carlo simulation approach. Their analyses show that inclusion of unexpected events, correlations between different activities, and learning curve effects impact the duration estimation significantly and therefore cost estimation of multi-well P&A campaigns.

Reducing the number of days and hours resources are used for P&A operations can have a large impact on the total costs. In addition the aforementioned studies, Abshire et al. (2012) describe a method for reducing the average time of setting plugs from 10.5 to 2.6 days. Hogg et al. (2014) present new tools and methodologies that has been developed with aim of reducing rig time. Saasen et al. (2011) describe an alternative method of plugging exploration wells using Bingham plastic unconsolidated plugging material for P&A of a field in the North Sea, which demonstrated a faster and more efficient placement of the plug that contributed to reduction of overall costs.

3.3 Shut Down Decisions

Mian (1992) provides formulae for the economic limit for oil and gas wells, which states the level of production at which operating costs including taxes cannot be covered by the income from production. These formulae do not take into account the cost of P&A operations, nor does it take into account that temporarily plugging and abandoning a well for a time period and open for production at a later point in time might be economically desirable. Rather, it simply gives the production levels at which cost of production exceeds income.

A more sophisticated approach in order to consider shut down decisions is to develop real options models. The aim of a real options model is to take into consideration the uncertainty in different factors that influence the value of a stock or a project, and to obtain a value of the flexibility the decision maker faces when future influencing factors are uncertain. Trigeorgis (1996) presents a range of such applications, including the option to temporarily shut down and restart operations and the option to permanently shut down an operation for a given salvage value. The latter is often modelled as an American put option.

McDonald et al. (2006) provide a simple example of how a permanent shut down option for a single oil well can be valued. They also present descriptions of how to model lognormal stock prices following a Brownian Motion, and discuss different methods for valuing options in relation to Monte Carlo simulation. They refer to Longstaff and Schwartz (2001) and to Broadie and Glasserman (1997) for two possible approaches to value American Option using Monte Carlo simulation.

Willigers et al. (2009) uses a least squares Monte Carlo (LSM) approach inspired by Longstaff and Schwartz (2001) to evaluate the exercise and continuation value of several options regarding an oil and gas project. Støre et al. (2016) investigates the option of an irreversible swich from oil to gas production and abandonment, where they treat oil and gas prices as stochastic processes following a Brownian motion.

3.4 Relevant Optimisation Problems

In this section, relevant general optimisation formulations from literature are presented. Note that these models have not been used as bases for all the models presented in this thesis (except one), but rather as sources of inspiriation.

First, we present the project scheduling problem as a network problem. Then, the Resource-Constrained Project Scheduling Problem (RCPSP) is described briefly. A special case of RCPSP is presented, where the objective is to maximise net present value of a project. Then, we present the Vehicle Routing Problem With Time Windows (VRPTW).

3.4.1 Project Scheduling

Project scheduling problems are often treated as network problems. The paths are structured as sets of arcs and nodes. The nodes represent points in time when one or more activities (arcs) are finished and new can begin (Lundgren et al., 2010). An illustration of a project scheduling example is given in Figure 3.1, where the arcs are labeled by activity name and duration, and the nodes represents point in time.

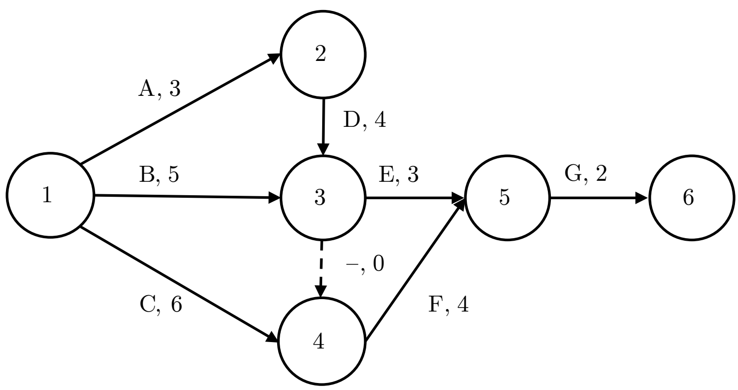

Figure 3.1: Project network example. Dashed line = dummy activity.

Some projects might include activities that make use of one or more resources of limited capacity. This extension form the basis for the Resource-Constrained Project Scheduling Problem (RCPSP) Artigues et al. (2008). In Brucker et al. (1999), an overview of notations, models and methods for the RCPSP is presented. To classify a RCPSP, they use an $\alpha|\beta|\gamma$-scheme that is widely used in job shop scheduling literature. One type of RCPSP called The Net Present Value Problem which can be formulated as follows:

$$max \sum_{j \in \mathcal{V}} C_j^F \beta^{c_j} \tag{3.4.1}$$

Subject to:

$$\begin{aligned}
&s_j - s_i \geq \delta_{ij}, && \forall (i,j) \in \mathcal{E}, && (3.4.2)\\
&s_0 = 0, && && (3.4.3)\\
&s_{n+1} \leq \bar{d}, && && (3.4.4)\\
&s_j \geq 0, integer, && \forall j \in \mathcal{V}, && (3.4.5)\\
&r_k(s,t) \leq R_k, && \forall k \in \mathcal{R}, t = 0, 1, ..., \bar{d} - 1. && (3.4.6)
\end{aligned}$$

This is a $PS|temp|\sum C_j^F \beta^{c_j}$ problem whose objective (3.4.1) is to maximise the cash flow while taking into account the discount rate at the current completion time of project j. Constraints (3.4.2) make sure that if there is a minimum or maximum time lag required between activity i and j where $j > i$, an arc with weight $\delta_{ij} = D_{ij}^{\min}$ or $\delta_{ij} = -D_{ij}^{\max}$ between i and j is introduced. Constraints (3.4.3) and (3.4.4) impose a requirement that the first activity start at time 0, and that the last activity start before the maximum project duration $\bar{d}$, respectively. Constraints (3.4.5) make sure that project start times are positive and integer. The resource constraints (3.4.6) make sure that the resource use does not exceed the capacity R_k of each resource k.

3.4.2 The Vehicle Routing Problem with Time-Windows

The Vehicle Routing Problem with Time Windows (VRPTW) is a distribution problem where vehicles based at a depot are to visit customers and fulfil known customer demand. This formulation of the VRPTW here is based on Christiansen (1996):

$$min \sum_{v \in \mathcal{V}} \sum_{(i,j) \in \mathcal{A}} C_{ij} x_{ijv} \tag{3.4.7}$$

Subject to:

$$\sum_{v \in \mathcal{V}} \sum_{j \in \mathcal{N}} x_{ijv} = 1, \qquad \forall i \in \mathcal{N} \setminus \{0\}, \tag{3.4.8}$$

$$\sum_{i \in \mathcal{N}} x_{ijv} - \sum_{i \in \mathcal{N}} x_{jiv} = 0, \qquad \forall j \in \mathcal{N}, v \in \mathcal{V}, \tag{3.4.9}$$

$$\sum_{j \in \mathcal{N}} x_{0jv} \leq 1, \qquad \forall v \in \mathcal{V}, \tag{3.4.10}$$

$$\sum_{i \in \mathcal{N} \setminus \{0\}} \sum_{j \in \mathcal{N}} D_i x_{ijv} \leq Q_v, \qquad \forall v \in \mathcal{V}, \tag{3.4.11}$$

$$x_{ijv}(t_i + T_{ij} - t_j) \leq 0, \qquad \forall (i,j) \in \mathcal{I}, v \in \mathcal{V}, \tag{3.4.12}$$

$$A_i \leq t_i \leq B_i, \qquad \forall i \in \mathcal{N}, \tag{3.4.13}$$

$$x_{ijv} \in \{0,1\}, \qquad \forall (i,j) \in \mathcal{A}, v \in \mathcal{V}. \tag{3.4.14}$$

The objective function (3.4.7) minimises the total transportation costs for all vehicles. Constraints (3.4.8) and (3.4.9) ensure that each node is visited, and that the same vehicle enters and leaves each node. Constraints (3.4.10) give each vehicle the possibility to leave the depot no more than once. Total demand for the nodes that vehicle v visits cannot exceed vehicle v's capacity. This is handled by Constraints (3.4.11). Constraints (3.4.12) ensure that if vehicle v travels directly from node i to node j, the start of service on node j starts after service at node i is completed and the vehicle has reached node j. Constraints (3.4.13) is the time window in which t_i can take its value. These time constraints prevent sub-tour formation without including sub-tour eliminating constraints explicitly. Constraints (3.4.14) impose binary restrictions on the transportation variable.

3.5 Contribution to Literature

Although MP has been used in the petroleum industry, including the Norwegian, no literature on MP related to P&A planning exist to our best knowledge. However, many of the decisions that the current models address are believed to be transferable to P&A. For example, some of the principles in the development planning problem of new oil fields covered in Nygreen et al. (1998) can be used in the strategic model where we look at shut down decisions.

The literature on cost estimation of P&A shows that methods such as regression analysis and simulations have been used in order to calculate costs of P&A activities. The use of MP for performing cost estimation and resource allocation related to P&A is however an unexplored territory. The same is true for obtaining cost efficient schedules of P&A operations of wells. The optimisation models developed in this thesis will therefore represent a new approach in this field of research, and include considerations that has been lacking in the literature up to now. One of the main contributions are the provision of models that could give valuable insights on how MP can be used to find optimal shut down times of fields, allocation of resources to perform P&A and day-to-day scheduling of multi-well campaigns. The models presented in this thesis are basic, and can be developed further to become robust planning and analysis tools.

In addition to providing models, we focus on discussions revolving challenges and benefits with a decomposition of a cost analysis into the different planning levels strategic, tactical and operational.

Chapter 4

Method and Data Collection

In this chapter, we present the methodology used for obtaining the data necessary to obtain our results. In Section 4.1, we explain in detail how we used publicly available information on wellbore statuses in combination with the approach of dividing P&A activities into phases, as described in Chapter 2, Section 2.2, to obtain the required remaining P&A work on wellbores on NCS. In Section 4.2, we give an overview of the fields included and excluded in this thesis. Finally, data collection regarding production levels, costs and other parameters are given in Section 4.3.

4.1 Wellbore Classification

We developed a database with all development wells on the NCS with basis on NPD's overview of wells and wellbores. In this database, information on which P&A phases that are necessary to conduct on each well was calculated. This section will present the steps we made in order to obtain this information.

4.1.1 NPD Guideline for Wellbore Classification

The NPD Guideline for designation of wells and wellbores, together with the statuses of each wellbore obtained from NPD's database on 21.04.2016 were used to classify whether a wellbore is part of a subsea or platform installation and whether the wellbore is a sidetrack or part of a multilateral well, or is the initial wellbore in the well.

The guideline provides the following definitions that is relevant for this thesis:

Well

A borehole which is drilled in order to discover or delimit a petroleum deposit and/or to produce petroleum or water for injection purposes, to inject gas, water or other medium, or to map or monitor well parameters. There are several categories of wells. A well may consist of one or several wellbores and may have one or several termination points.

Wellbore

The location of the well from one termination point to the wellhead. A wellbore may consist of one or more well tracks.

Well track

The part of a wellbore (well path) which extends from a point of drilling out on the existing wellbore (kick-off point) to a new termination point for the well.

Multilateral wellbore

Has more than one wellbore radiating from the main wellbore. In contrast to sidetracked wells where the first bottom section is plugged back before a sidetrack is drilled, multilateral wellbores have more than one wellbore open at the same time.

A well's or wellbore's name is determined by several items, with a format that can generally be described as #/#-X-# XXXXX, where # is a number and X is a letter. Here, nine items are used, but usually one does not need all nine to name a well or wellbore. These items items are:

- **Item I**: Quadrant number
- **Item II**: Block number
- **Item III**: Identification of the wellbore or name of the installation
- **Item IV**: Well number
- **Item V**:

  - **S**: Exploration wellbore planned to be deviated
  - **A,B, etc**: Sidetracks
  - **R**: Re-entered exploration wellbores
  - **Y**: Planned as multilateral wellbores

- **Item VI**: Number as count of the number of re-entries or welltracks in multilateral wellbores
- **Item VII**: H if wellbore is subsea
- **Item VIII**: F# if well belongs to multifield wellbores (wellbore for first field is not using Item VIII)
- **Item IX**: Item used for more detailed identification of a wellbore (e.g. technical sidetracks)

An example is the wellbore $2/4-K-12A$ which is a wellbore located in quadrant 2 and block number 4, drilled from installation Ekofisk K, and is a sidetrack (hence the "A" at the end), that belongs to the twelfth well in that installation. It is not a subsea wellbore, as it does not bear the letter H (The Norwegian Petroleum Directorate, 2014).

4.1.2 Wellbore Statuses

In order to identify the remaining phases P&A operations of a well or wellbore, we used the wellbore statuses that is given for all wellbores on the NCS by the NPD, and made assumptions on how many of the phases described in Oil and Gas UK (2015) was required for each status. Conversations with the authors of the bachelor thesis Spieler and Øia (2015) have provided sufficient insights on this categorisation.

- **Online/Operational**: Development well that is completed. Either ready for production/injection or producing/injecting. For all wellbores in a well that has this status, phase 1 and 2 must be executed. If the wellbore is a sidetrack or part of a multilateral well, phase 3 is only performed for the initial wellbore.
- **Producing/Injecting**: This status is not part of the NPD's attribute list, but appears in the database for some wellbores. This status has been assumed to be the same as Online/Operational.
- **Plugged**: Development well that is plugged, but the field is still producing. This status also apply to wells with sidetracks where the initial wellbore

has been plugged, but the sidetracks has another status. If all wellbores in a well has status plugged (or junked), only phase 3 of P&A remains. If not, phases 1 and 2 must be executed for the the other wellbores before phase 3 is executed for the initial wellbore.

- **P&A**: Production/injection in the wellbore is terminated and the field is closed down. No phases required.
- **Junked**: The drilling of the well was terminated due to technical issues. No remaining P&A phases required.
- **Closed**: Wellbore that is closed in a period. Ultimately needs all P&A phases to be executed. If this is a sidetrack wellbore, only phases 1 and 2 is needed before phase 3 is executed the initial well.
- **Suspended**: Well that is temporarily abandoned. Need all phases of P&A if the well is contains this single wellbore, and phases 1 and 2 if it is a sidetrack or multilateral wellbore before phase 3 is executed on the initial wellbore.
- **Drilling**: The well is currently under drilling, logging, testing or plugging. As we do not now the drilling purpose, these wellbores are excluded.
- **Predrilled**: Predrilling of the well is completed. Assumed to need phases 1 and 2 if it is a sidetrack and all three if it is an initial wellbore.
- **No status**: Some wells are planned for, but not drilled yet. These wells do not have any status in NPD. These are excluded from our analysis as we do not know whether they will actually be drilled.

4.1.3 Example of Categorisation

In order to explain the method used for calculating the number of phases needed for each field divided in phases 1 and 2, and phase 3, while distinguishing between subsea and platform wells, we provide an example. We use the field Svalin with ten development wellbores, which is described in Table 4.1. The name of the wellbore is given in the first column. In the second column, the well name is given, and in the thrid column, the status of the well is reported.

Table 4.1: Example of method for obtaining phase requirements for Svalin

Wellbore	**Well**	**Status**
25/11-G-37	25/11-G-37	Plugged
25/11-G-37 A	25/11-G-37	Plugged
25/11-G-37 B	25/11-G-37	Plugged
25/11-G-37 CY1	25/11-G-37	Online/Operational
25/11-G-37 CY2	25/11-G-37	Online/Operational
25/11-H-3 AH	25/11-H-3	Online/Operational
25/11-H-3 H	25/11-H-3	Plugged
25/11-H-4 AH	25/11-H-4	Plugged
25/11-H-4 BH	25/11-H-4	Online/Operational
25/11-H-4 H	25/11-H-4	Plugged

We see that well 25/11-G-37 consists of five wellbores, of which three is plugged and two is Online/Operational. This means that that the three wellbores with status Plugged has been through phases 1 and 2, and that these phases remains for the two wellbores with status Online/Operational. In total, This well therefore requires two phase 1 two phase 2 operations and one phase 3 operation. For well 25/11-H-3, which is a subsea well since the wellbore names carry an H at the end, one phase 1 and one phase 2 operation is required, together with one phase 3 operation. The same applies for the last well 25/11-H-4. The resulting phase requirement for the Svalin field is given in Table 4.2

Table 4.2: Phase requirements for Svalin

Wellbore	**Well**	**Status**	**Phases required**
25/11-G-37	25/11-G-37	Plugged	3
25/11-G-37 A	25/11-G-37	Plugged	None
25/11-G-37 B	25/11-G-37	Plugged	None
25/11-G-37 CY1	25/11-G-37	Online/Operational	1, 2
25/11-G-37 CY2	25/11-G-37	Online/Operational	1, 2
25/11-H-3 AH	25/11-H-3	Online/Operational	1, 2
25/11-H-3 H	25/11-H-3	Plugged	3
25/11-H-4 AH	25/11-H-4	Plugged	None
25/11-H-4 BH	25/11-H-4	Online/Operational	1, 2
25/11-H-4 H	25/11-H-4	Plugged	3

This methodology was performed for each wellbore on each field on the NCS. This enabled us to investigate how many operations of the different phases that are needed for each field, and to distinguish between the required technology. Figure 4.1 illustrates the general method for determining the number of phases needed for each wellbore. After this categorisation, we identified whether the wellbore was a subsea or platform wellbore.

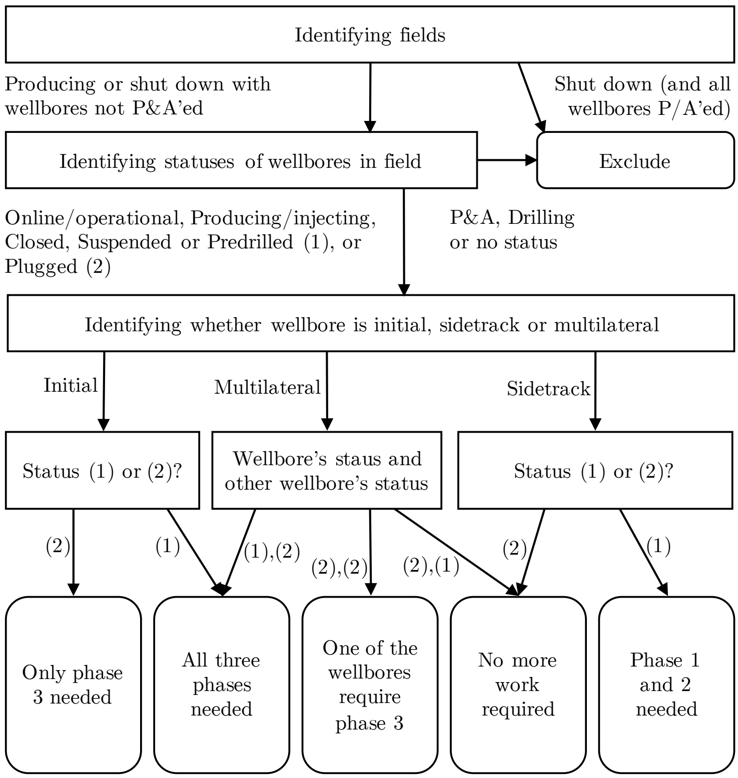

Figure 4.1: Method for determining number of phases needed for each wellbore.

4.2 Field Information

The fields included and excluded from this thesis is based on NPD's data on fields that have status Producing and Shut down, respectively. For some fields that have status Producing, decommissioning plans have already been submitted, meaning that after all P&A work is done, they will change status to Shut down. Some fields with status Shut down is included since wellbores in these fields have not changed their status to P&A. In Table 4.3, all fields that are included in the cost estimation and optimisasion models are presented:

Table 4.3: Fields included in this thesis

Fields included in this thesis			
Tor	Alve	Alvheim	Atla
Balder	Brage	Brynhild	Bøyla
Draugen	Edvard Grieg	Ekofisk	Eldfisk
Embla	Fram	Fram H-Nord	*Gaupe*
Gimle	Gjøa	Goliat	Grane
Gudrun	Gullfaks	Gullfaks Sør	Gungne
Gyda	Heidrun	*Heimdal*	*Hod*
Huldra	Hyme	Jette	*Jotun*
Knarr	Kristin	Kvitebjørn	Marulk
Mikkel	Morvin	Njord	Norne
Ormen Lange	Oseberg	Oseberg Sør	Oseberg Øst
Oselvar	*Rev*	Ringhorne Øst	Sigyn
Skarv	Skirne	Skuld	Sleipner
Snorre	Snøhvit	Statfjord	Statfjord Nord
Statfjord Øst	Svalin	Sygna	Tambar
Tambar Øst	Tordis	Troll	Trym
Tune	Tyrihans	Ula	Urd
Vale	Valemon	Valhall	*Varg*
Vega	Veslefrikk	Vigdis	Vilje
Visund	Visund Sør	Volund	Volve
Yme	Åsgard		

The fields that have status Shut Down or are planned to be shut down as production has stopped but contains wellbores that do not have status P&A or Junked are highlighted in italic in the table.

For Tor, a redevelopment of the field is being evaluated. Gaupe is expected to cease production in 2016. Heimdal has not been producing since 2011, but the platform is used as gas processing centre for other fields. Hod has not produced since 2013 and awaits decommissioning. Some wellbores in this field are classified as multifield and are actually producing petroleum for Valhall field. Production stopped in 2014 in Huldra, and P&A of the wells are planned to be completed in 2016. The operator in Jotun field has started shutting down the field in April 2016. Operators in Rev field delivered a cessation plan to authorities in 2015. A redevelopment of the Snorre and Yme fields are being evaluated. Shut down of the Varg field was decided early in 2016. We treat the fields of which shut down has been decided and the fields where redevelopment is being evaluated as candidates for P&A in the near future. Note that Sleipner Øst and Sleipner Vest are separate fields in the NPD database. However, they are merged here to one field, Sleipner, due to the fact that production and cost data from Rystad Energy is only obtainable for the merged fields.

Some fields are excluded from our analysis. Fields that has been shut down and consist of wells that has status P&A or Junked and only these statuses have been omitted. Fields that are listed as plan for development and operation (PDO) approved, i.e. Flyndre, Gina Krog, Hanz, Ivar Aasen, Johan Sverdrup, Maria, Martin Linge, and Aasta Hansteen are also excluded. Although some of these fields has already started producing according to NPD's production data, it is reasonable to assume that many more wells will be drilled in the future to maximise production. This means that we have too little information about how many P&A operations are required. Also, little reliable information about future production for this fields are obtainable. Some other fields are listed as producing fields in NPD's database, but lack presence in the database we used to obtain production forecast. These include Enoch, Islay and Blane. These are also excluded from the thesis.

4.3 Data Collection of Parameters

This section describes how we obtained data on production forecast, costs, durations, prices, discount and inflation rates.

4.3.1 Production Forecast

Estimation of a field's future production was collected from the database UCube which is developed by the oil and gas consultancy company Rystad Energy. These forecasts are based on the estimated recoverable resources present in the field, and do not take into account uncertainties related to the oil price, operating and maintenance costs, and the installations' technical condition. This data gave insight on future production and formed the basis for calculating the optimal shut down time of fields. Production will be treated as deterministic. UCube defines their production forecast as the expected, annualised rate of extraction of hydrocarbons, and they usually follow a given constant exponential decline rate (Rystad Energy, 2016).

4.3.2 Costs and Durations

Data regarding costs and duration of the P&A activities are collected from different sources. Minimum, most likely, and maximum values for durations, and daily rates of vessel rental are collected from Spieler and Øia (2015) with some modifications. These are given in Appendix A. When estimating total costs of P&A-operations, we assume an average wait on weather (WOW) factor of 20% and an average non-productive time of 20%. Operational expenses (OPEX) for each field were collected from UCube. In collecting the values for total OPEX, we chose to include the data on sales, general and administrative (SG&A) OPEX, Transportation OPEX and Production OPEX. UCube defines these costs as the following:

SG&A OPEX

Represent operational expenses not directly associated with field operations. Includes administrative staff, office leases, related benefits (stock and stock option plans), and professional expenses (legal, consulting, insurance).

Transportation OPEX

Represents the cost of bringing oil and gas from the production site or processing plant to the pricing point (only upstream transportation). Includes transport fees and blending costs.

Production OPEX

Operational expenses directly related to the production activity. Includes materials, tools, maintenance, equipment lease costs and operation related salaries. Depreciation and other non-cash items are not included.

We did not include other costs, such as facility CAPEX. This cost type is more related to establishment of new installations in a field. Although this cost might be relevant, it was difficult to observe any relationship between facility CAPEX and production levels. We therefore chose to omit these costs, as we also omit future possible redevelopment of fields and future establishment of wells that might increase production.

Costs related to temporary shut downs, reopening and monitoring of fields have not been obtained as to our best knowledge no available estimates exist on these figures. We use only fictitious numbers for these when it is relevant. As this thesis is more focused on establishing models that can be used for analysis purposes rather than obtaining realistic monetary results, we believe that the approach of using fictitious figures for these costs is sufficient for our purposes.

4.3.3 Calibrating Field Data

Some fields in the NPD database are split in several fields in the UCube database. Some of the fields reported in the UCube database refer to different production installations, but this is not always the case. In order to obtain the correct production forecast, we needed to compare historical data from the NPD with the historical data from UCube for all fields listed in Figure 4.3, and merge some of the fields in UCube in order to obtain the same historical figures as the NPD reports. This way, we obtained production and OPEX forecast for each field and ensured that this was in accordance with historical data reported from the NPD. As we did not observe any clear connection between the NPD's categorisation of production facilities and UCubes data on installations, we were not able to split a field into installations and obtain correct forecast for these.

We believe that this calibration was necessary in order to obtain as good estimates on field production and costs as possible. However, some challenges arose when we we observed large differences in forecast OPEX for some fields. We will comment on these challenges later.

4.3.4 Discount Rate

When considering NPV, it is important to justify the reasoning behind the discount rate used. In a report from PA Consulting, the discount rate is defined as the rate of return that could be earned in investment with similar risk, or the opportunity cost of capital. The discount rate used in our base cases is given by the Norwegian Ministry of Finance, and is dependent on the time the cash flow incurs. These rates are given in Table 4.4.

Table 4.4: Discount rates (The Norwegian Ministry of Finance, 2014)

	0-40 years	**40-70 years**	**>70 years**
Discount rate	4.0%	3.0%	2.0%

The reason why the discount rates are dependent on time periods is that on a long horizon, there is higher uncertainty regarding option returns, and therefore the rate is declining with time. For planning purposes, this declining discount rate creates some challenges: If one is to make a valuation of the net present value of a cash flow at a time that is uncertain (such as shut down decisions of a field), it will be cheaper to bear that cost in year 40 than in year 41. This might be intuitively reasonable if the rates were fixed over time. However, the time windows presented in Table 4.4 are not fixed to specific years, but time windows. This means that in the future, the decision maker will face a new discount rate for some of the years on which she based her initial decisions. This phenomenon is called time inconsistency, and describes a situation where the preferences of the decision maker changes over time. It is expected that this time inconsistency will be apparent for the results of the strategic model. It is important then to realise that if the model calculates an optimal shut down time for a field is a point in time in far future, this might not be the optimal shut down time if the same analysis is to be conducted at a later point in time. Hence, optimal shut down time for fields in the far future should be interpreted with caution.

4.3.5 Inflation Rate

In their database UCube, Rystad Energy operates with a constant inflation rate of 2.5%. In our base case, we use the same inflation rate to obtain the current values of the forecast nominal values on OPEX and petroleum prices. A flat inflation rate is not realistic, at least not on the short term. According to OECD, the annual inflation rate in the OECD countries has fluctuated considerably the last 15 years. In 2000, the annual inflation rate was 3.97%, while in 2015 it was 0.58%. Clearly, the inflation rate will affect the real prices prevailing at a given year. However, since the inflation rate is applied both for future crude oil prices and OPEX, the relations between these two values will be the same. Since our analyses on the strategic level mainly consider long term considerations, we proceed with the assumption that petroleum prices and OPEX values can be inflation adjusted with a rate of 2.5%.

4.3.6 Petroleum Prices

In our strategic optimisation model and real options model, we operate with Rystad Energy's crude oil and gas price forecast obtained from UCube. They operate with a forecast which is much more aggressive than for instance World Bank's estimates on the short term. On the longer term, they believe that the prices will flat out. For the NGL price, we used today's prices obtained from (U.S. Energy

Information Administration, 2016), and assumed that they are perfectly correlated with gas prices, as no forecast on NGL prices on a long term was obtainable. When converting all prices to the units used in this thesis, $[USD/Sm^3]$, we used the conversions given in Appendix C.

Chapter 5

Data Processing and Cost Estimate

This chapter consists of the following: In Section 5.1 we present the results from the data processing of all current development wellbores on the NCS and the associated required phases needed according to the method presented in Chapter 4, Section 4.1. Then, we present the high level cost estimate in Section 5.2. The chapter concludes with a summary of the results and related discussions in Section 5.3. The results from the cost estimation are used as input parameter in the strategic model and real options model, while results regarding phase requirement are used in the tactical and operational model. This chapter aims at answering the following research questions:

- How much P&A work is required for current development wells on the NCS?
- What are the estimated total costs of P&A activities on the NCS for current producing fields?

5.1 Well Status and Phase Requirement

The number of development wellbores divided in subsea and platform wellbores that must be P&A'ed is illustrated in Figure 5.1, and the distribution of number of wellbores that need different P&A phases on is illustrated in the Figure 5.2. In total, we analysed 3308 development wellbores on the NCS.

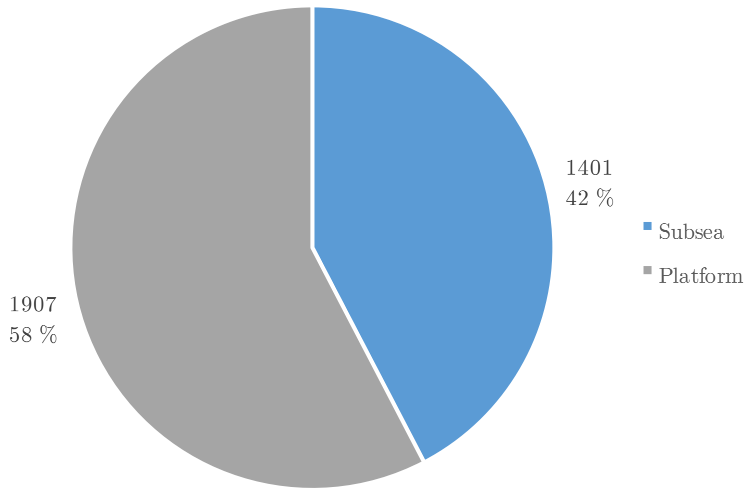

Figure 5.1: Total number of wellbores distributed in subsea and platform that require P&A.

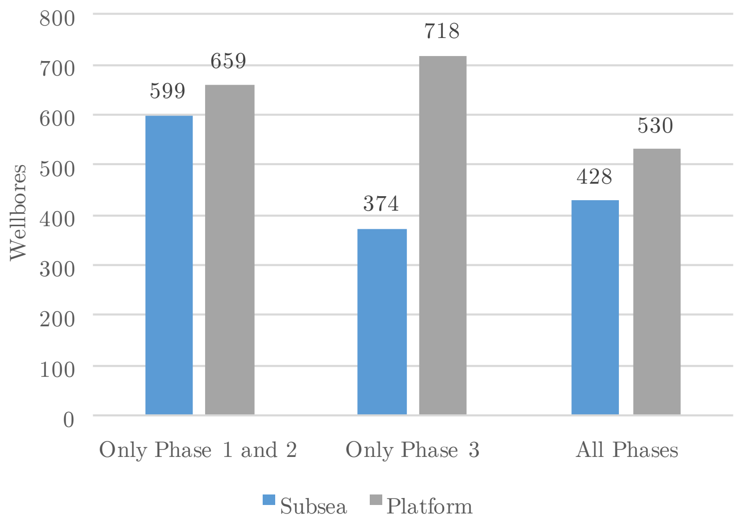

Figure 5.2: Distribution of remaining phases required for wellbores on the NCS.

Figure 5.2 tells us that there are many sidetracks and/or wellbores that are part of a multilateral well (this is interpreted from the numbers in the two leftmost columns). Further, a large proportion of the wellbores that only need removal of wellhead (phase 3) are platform wells, and the total of wellbores requiring only this phase amounts to almost a third of the total. The two rightmost columns are the number of wellbores that either are initial wellbores in the well, or the only wellbore in the well and are still producing, or one of the wellbores in a multilateral wellbore that is producing. The total time required for P&A and the largest proportion of costs are related to the two third of the total number wellbores, i.e. the wellbores that requires more than the last phase (as phase 3 operations are quick and thus not particularly expensive).

In Appendix D, Table D1, the number of phases needed for each fields are given. The distribution shows that there are large differences in the need of phases on the NCS. An excerpt from this result is given in Table 5.1.

Table 5.1: Excerpt of phase requirement on the NCS

Field	**Type**	**Well-bores**	**Phase 1**	**Phase 2**	**Phase 3**	**Total Phases**
Alve	Subsea	3	2	2	2	6
Ekofisk	Platform	281	168	168	193	529
Ekofisk	Subsea	16	16	16	16	48
Eldfisk	Platform	94	53	53	59	165
Gullfaks	Platform	199	127	127	130	384
Gullfaks	Subsea	6	1	1	6	8
Kvitebjørn	Platform	17	12	12	16	40
Ormen Lange	Platform	1	0	0	1	1
Ormen Lange	Subsea	26	19	19	22	60
Oseberg	Platform	123	72	72	73	217
Sygna	Subsea	3	3	3	3	9

Note that the number of required phase 1 and phase 2 operations are identical. This is because, based on available information, we assumed that either a wellbore has either been through phases 1 and 2, all of the phases, or none of the phases. This assumption is in accordance with a similar analysis performed by Spieler and Øia (2015) except for some wellbores which they categorised as only requiring phases 2 and 3. Their analysis was based on more data than ours, but since the difference was relatively low, we believe that treating the need for phase 1 and 2 as the same as a fair assumption.

5.2 High Level Cost Estimate

In Appendix E, Table E1, we present the result from the estimation of P&A costs on the NCS with different duration input data and vessels used for different phases[1]. We assume that all fields uses the same distribution of the PWC, ICP and SM technologies (i.e. 40% ICP, 35% PWC and 25% SM). In Figure 5.3, the aggregated values for all fields for each combination of durations and vessel choice for setting surface plug and removal of wellhead are presented. ”Max”, ”ML” and ”Min” refer to maximum, most likely and minimum values of durations, respectively. The first letter after ”Max”/”ML”/”Min” refers to the vessel used for setting surface plug: R - RLWI, M - MODU. The last letter refers to the vessel used for removing the wellhead: R - RLWI, L - LCV.

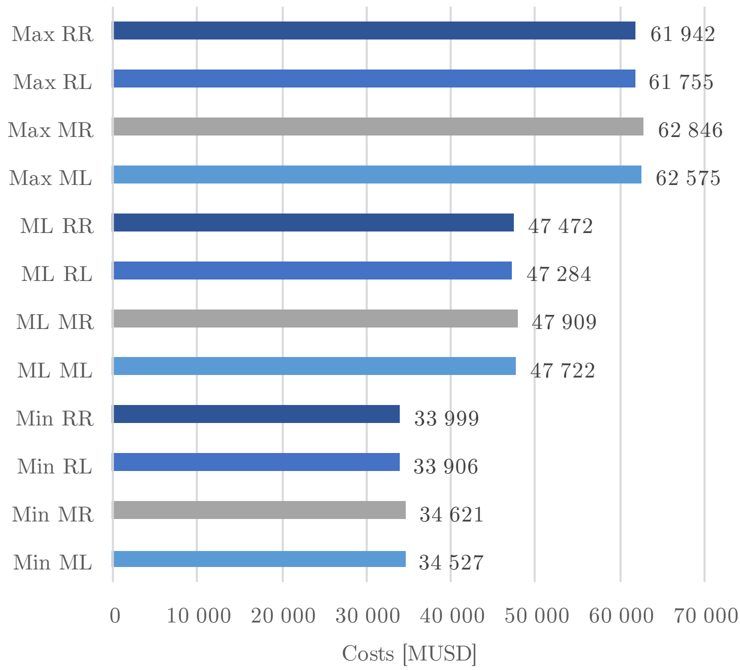

Figure 5.3: Total costs of P&A operations on the NCS for different methods and durations

[1] After performing the analysis, we observed a minor error in an intermediate calculation regarding phase 3 operations for subsea wells. The error resulted in an error of approximately 0.06% on the total cost estimate. The numbers should therefore be adjusted slightly upwards.

These figures should be interpreted with caution. The distribution of technologies might not be the same for each field. Therefore, some of the costs should probably be adjusted upwards for some fields and downwards for others. It is important to emphasise that these costs are restricted to only P&A. We have not included mobilisation costs or learning effects or any costs related to the decommissioning of installations. It is also important to note that these figures represent the costs if all fields were to be shut down today. Hence, effect of discount rates is not included.

In addition, each of the values obtained does neither take into account the possibility of combinations of durations nor possibility of combinations on the choice of vessels to perform the aforementioned procedures in a well. However, as we observe from Figure 5.3, there are not large differences in total costs within each of the values of the durations, which may indicate that the total costs are more sensitive to durations of the operations.

The figures for the most likely case with MODU as the vessel to set surface plug, as well as LCV to remove wellhead is used as the base case in the strategic model, i.e. the ML ML case. This assumption is based on the fact that the probability that the true durations are close to the most likely case is higher than for the other, and that the common way of performing P&A operations today is to use MODU and LCV for these operations (Spieler and Øia, 2015). When we look at the coordination of vessels in the tactical and operational model, we allow different vessels to execute different phases.

It is important to mention that some of the analyses performed by Spieler and Øia (2015) suggested if future P&A were to be performed by an RLWI only, and without the use of SM, the total costs could reduce by approximately 40%. Such considerations are not covered in this thesis. We only look at the cost differences allowing different vessels to set the surface plug and remove the wellhead. This assumption is valid throughout the report.

The numbers shown in Figure 5.3 should be interpreted as coarse estimates. Many factors have not been included, and these numbers are based on the assumption that all wellbores were to be P&A'ed today and that all the necessary vessels are available. Moreover, we have assumed that no platform wellbores need to be P&A'ed by mobile units. However, the results show the order of magnitude of the costs operators (and indirectly the Norwegian government) must face. According to the ML ML case, the total costs amounts to 47 722 MUSD for the current development wellbores on the NCS. Bearing in mind that new wellbores are being continuously drilled on the NCS, this cost should be adjusted upwards when we look at the total cost operators and the Government must face in the future. Due to the taxation system, the government indirectly pays 37 223 billion NOK of these costs.

5.3 Conclusion Well Status and Cost Estimate

The findings from investigating well status and the results of the cost estimation can be summarised as follows:

- There are approximately 3308 development wellbores currently on the NCS that requires P&A some time in the future, most of them platform wellbores.
- There are large differences in phases required for fields on the NCS.
- The total cost related to P&A are probably not that sensitive to the choice of vessel to set surface plug and remove wellhead on subsea wellbores, but possibly more sensitive to the duration of the P&A operations.
- The ML ML case suggest that the total cost of P&A of current development wellbores on the NCS amounts to cost in an order of magnitude of tens of thousands million USD.

Chapter 6

Models

This chapter contains the mathematical formulations for the models used in this thesis. We start by describing the strategic optimisation model in Section 6.1, followed by the real options model in Section 6.2. Then we move to the tactical planning level, where we present a tactical optimisation model, and an alternative formulation to the tactical model in Sections 6.3 and 6.4, respectively. We provide a short discussion on the advantages and disadvantages of these models in Section 6.5. Then, in Section 6.6, we present the operational model. Lastly, we present a possible approach to estimating future production on a well level in Section 6.7.

6.1 Strategic Model

This section provides a problem description, model assumption and model formulation for the strategic model.

6.1.1 Problem Description

The strategic model is developed with the aim of answering the following research questions:

- When is the optimal time for shut down of fields on the NCS?
- How can different optimisation models provide answers to these questions?

The problem considers a set of fields currently producing petroleum products on the NCS. Production is split into oil, gas and NGL and is determined by an input profile for each of the products for each field. During the time horizon given by the production profile, a field may be shut down due to negative future NPV of the project, or it may produce until the production input data is zero, and shut down has to be conducted within a time limit. A field may choose to temporarily shut down in one time period and restart production at a later point in time. For each year a field is producing, a yearly OPEX incurs which is independent on production levels.

No OPEX nor income will incur in the period where the field is temporarily shut down. A one-off cost associated with the temporary shut down, and a yearly monitoring cost for each period the operator chooses to keep the field temporarily shut down is assumed.

If a field is producing in one year, it must have produced the previous year as well, except the first time period for the relevant field. All fields need to be shut down some time during a predetermined long time horizon. The permanent shut down decision is irreversible, meaning that if a field is shut down, all future production must be equal to zero.

Some fields are producing both oil, gas and NGL, but others are only producing one or two of these. Multiplying these production levels with the relevant prices gives the yearly income. Subtracting OPEX gives yearly profits. In addition to OPEX, the temporary and permanent shut down cost and monitoring costs are subtracted to obtain the objective function value.

The objective is to maximise the NPV of total profits on the NCS, and to investigate the optimal shut down time for each field.

6.1.2 Model Assumptions

This model assumes the following:

- Production levels are deterministic.
- Operational expenses (OPEX) are deterministic and are the only costs associated with production.
- Costs related to P&A are based on the ML ML case from the cost estimate given in Chapter 5.
- Mobilisation costs and other P&A and shut down related cost not captured in the cost estimation is not included.

- If production stops, the field must be temporary or permanent shut down in the next period.
- If temporary shut down is chosen, the field must be continuously monitored until reopening of the field or permanent shut down is performed.
- We assume that the monitoring cost is included in the one-off temporary shut down cost in the year the field is temporary shut down and that re-opening is mandatory if permanent shut down is not performed within the time limit.
- Petroleum prices are deterministic.
- All production of oil, gas and NGL are being sold at the prevailing price.
- All fields are independent. Decisions on one field does not affect decisions on other fields. We will include dependencies in Chapter 7.
- Fields that has no forecast production must be shut down during the current year.
- Permanent shut down costs incur in one year only.
- All fields must be shut down during the time horizon.

6.1.3 Sets

Let $\mathcal{F}$ be the set of fields that are candidates for shut down. We choose to split this set in two: $\mathcal{F}^P$ are the fields that are associated with positive production levels at least during the first time period, while $\mathcal{F}^N$ are the fields that are not decommissioned yet and has no forecast production in any time period. Let $\mathcal{T}$ denote the set of all time periods, and the set T_f the set of time periods where the production data in field $f \in \mathcal{F}$ is positive. Since the production of oil, gas and NGL are independent, we introduce a set $\mathcal{S}$ that consists of these three products. The sets used in this model are summarised in Table 6.1:

Table 6.1: Sets in the strategic model

Set	Description
$\mathcal{F}$	Fields
$\mathcal{F}^P$	Producing fields
$\mathcal{F}^N$	Non-producing fields
$\mathcal{T}$	Time periods
$\mathcal{T}_f$	Time periods of production
$\mathcal{S}$	Products (oil, gas and NGL)

6.1.4 Parameters

The shut down costs for each field f is given by the parameter C_f^{PSD}. The OPEX for each field f in time period $t \in \mathcal{T}$ is given by the parameter C_{ft}^{O}. The one-off temporary shut down cost for each field f is given by the parameter C_f^{TSD}. The yearly monitoring cost for each field f is given by C_f^{MON}. If reopening of a field f is performed, a cost of C_f^R is incurred.

Let X_{st} be the forecast prices of product $s \in \mathcal{S}$ in time period $t \in \mathcal{T}$. Further we let P_{fst} be the forecast production of product s in field f in time period t. Then, let T^Y be the last entry in the set $\mathcal{T}$, and TL the time limit between temporary shut down and permanent shut down.

All income from production, OPEX and costs associated with shut down of the field must be discounted. Let α_t be the inverse discount rate at time t. In addition, the petroleum prices and OPEX are given in nominal values at given time periods based on a given inflation rate. These values must be discounted back to today's prices, so an inverse inflation rate in addition to the discount rate α_t at a given point in time t is needed. We denote this β_t. All parameters are summarised in Table 6.2.

Table 6.2: Parameters in the strategic model

Parameter	Description
C_f^{PSD}	Permanent shut down cost
C_{ft}^{O}	OPEX
C_f^{TSD}	Temporary shut down cost
C_f^{MON}	Monitoring cost
C_f^{R}	Reopening cost
X_{st}	Petroleum prices
P_{fst}	Petroleum production
T^{Y}	Number of time periods
TL	Time limit
α_t	Inverse discount rate
β_t	Inverse discount and inflation rate

6.1.5 Variables

Let y_{ft} be a binary variable that takes the value 1 if field f is permanent shut down in time period t, and 0 otherwise, and x_{ft} a binary variable that takes the value 1 if field f is temporary shut down in period t, and 0 otherwise. The variable δ_{ft} is 1 if field f is not producing in time t and waiting on shut down or reopening and records the time period for which a field is monitored, and 0 otherwise. Then, let p_{fst} be the production of product s in field f at time t. Let u_{ft} be a binary variable that takes the value 1 if field f is producing at time t, and 0 otherwise. If field f reopens the field for production, the binary variable v_{ft} takes the value 1, and 0 otherwise. All variables are listed in Table 6.3.

Table 6.3: Variables in the strategic model

Variable	Description
y_{ft}	Permanent shut down
x_{ft}	Temporary shut down
δ_{ft}	Monitoring
p_{fst}	Production level
u_{ft}	Production
v_{ft}	Reopening

6.1.6 Constraints

In this section, all constraints in the strategic model will be presented together with an explanation.

Field shut down

Constraints (6.1.1) make sure that the permanent shut down decisions must and can only be made once:

$$\sum_{t \in \mathcal{T}} y_{ft} = 1, \qquad \forall f \in \mathcal{F} \tag{6.1.1}$$

The operators can choose to temporarily shut down a field. Then, reopening of the field must happen some time in the future, or permanent shut down must be conducted within a time limit. This is handled by Constraints (6.1.2).

$$x_{ft-1} - \sum_{\tau=t}^{t+TL} y_{ft} - \sum_{\tau=t}^{T^Y} u_{ft} \leq 0, \qquad \forall f \in \mathcal{F}^P, t \in \mathcal{T} \mid t-1 \in \mathcal{T} \tag{6.1.2}$$

Constraints (6.1.3) ensure that if the operator decides to temporarily shut down the field, the field must be monitored, permanently shut down, or produce in the next period.

$$x_{ft-1} - \delta_{ft} - y_{ft} - u_{ft} \leq 0, \qquad \forall f \in \mathcal{F}^P, t \in \mathcal{T} \mid t-1 \in \mathcal{T} \tag{6.1.3}$$

We need to count the number of time periods a field is monitored, and make sure that if a field is monitored in one period, it must be monitored in the next period if the field is not shut down or reopened. This is ensured by Constraints (6.1.4):

$$\delta_{ft-1} - \delta_{ft} - y_{ft} - u_{ft} = 0, \qquad \forall f \in \mathcal{F}^P, t \in \mathcal{T} \mid t-1 \in \mathcal{T} \tag{6.1.4}$$

Reopening of field

If the operator chooses to temporary shut down the field and reopen the field for production, we need to record this in order to attach reopening cost to this decision. Constraints (6.1.5) make sure that if a field is not producing in period $t-1$ and produces in period t, the reopening variable must take the value 1.

$$u_{ft} - u_{ft-1} - v_{ft} \leq 0, \qquad \forall f \in \mathcal{F}^P, t \in \mathcal{T} \mid t-1 \in \mathcal{T} \tag{6.1.5}$$

Production

Production in a field at a given point in time is given by the production forecast and has to be 0 if the production binary variable u_{ft} is 0. This is handled by Constraints (6.1.6):

$$p_{fst} - P_{fst}u_{ft} = 0, \qquad f \in \mathcal{F}, s \in \mathcal{S}, t \in \mathcal{T} \tag{6.1.6}$$

Constraints (6.1.7) states that if production occurs in period $t-1$, either production, temporary or permanent shut down must occur in the next period:

$$u_{ft-1} - u_{ft} - x_{ft} - y_{ft} \leq 0, \qquad \forall f \in \mathcal{F}^P, t \in \mathcal{T} \mid t+1 \in \mathcal{T} \tag{6.1.7}$$

In a given period, only one of the decisions can be taken. Either the field produces, starts temporary shut down, starts permanent shut down, or is being monitored. This is handled by Constraints (6.1.8):

$$\delta_{ft} + x_{ft} + u_{ft} + y_{ft} \leq 1, \qquad \forall f \in \mathcal{F}^P, t \in \mathcal{T} \tag{6.1.8}$$

Variable declarations

The variables used in this model is given by Equations (6.1.9) - (6.1.14):

$$y_{ft} \in \{0,1\}, \qquad \forall f \in \mathcal{F}, t \in \mathcal{T}, \tag{6.1.9}$$
$$x_{ft} \in \{0,1\}, \qquad \forall f \in \mathcal{F}, t \in \mathcal{T}, \tag{6.1.10}$$
$$\delta_{ft} \in \{0,1\} \qquad \forall f \in \mathcal{F}, t \in \mathcal{T}, \tag{6.1.11}$$
$$p_{fst} \geq 0, \qquad \forall f \in \mathcal{F}^P, s \in \mathcal{S}, t \in \mathcal{T}_f, \tag{6.1.12}$$
$$u_{ft} \in \{0,1\}, \qquad \forall f \in \mathcal{F}^P, t \in \mathcal{T}_f, \tag{6.1.13}$$
$$v_{ft} \in \{0,1\}, \qquad \forall f \in \mathcal{F}^P, t \in \mathcal{T}_f \tag{6.1.14}$$

6.1.7 Objective Functions

We propose two objective functions. The first, (6.1.15), is used for investigating the optimal shut down time of each field without considering the costs of shut down, i.e. find the period in which the NPV of the project turns negative. The rationale behind this is explained in Chapter 7. The second, Function (6.1.16) includes all decisions. The functions are maximisation functions, and the objective is to maximise the profits from petroleum production.

$$max \sum_{f \in \mathcal{F}^P} \sum_{s \in \mathcal{S}} \sum_{t \in \mathcal{T}_f} \Big[X_{st} p_{fst} - C^O_{ft} u_{ft} \Big] \beta_t \tag{6.1.15}$$

$$\begin{aligned} max \sum_{f \in \mathcal{F}^P} \sum_{s \in \mathcal{S}} \sum_{t \in \mathcal{T}_f} \Big[X_{st} p_{fst} - C^O_{ft} u_{ft} \Big] \beta_t - \sum_{f \in \mathcal{F}} \sum_{t \in \mathcal{T}} C^{PSD}_f y_{ft} \alpha_t \\ - \sum_{f \in \mathcal{F}^P} \sum_{t \in \mathcal{T}} C^{TSD}_f x_{ft} \alpha_t - \sum_{f \in \mathcal{F}^P} \sum_{t \in \mathcal{T}} C^{MON}_f \delta_{ft} \alpha_t - \sum_{f \in \mathcal{F}^P} \sum_{t \in \mathcal{T}} C^R_f v_{ft} \alpha_t \end{aligned} \tag{6.1.16}$$

The main strategic model is thus given by Constraints (6.1.1) - (6.1.14) and the objective function (6.1.16).

6.2 Real Options Model

The strategic optimisation model is deterministic. In reality, there are many uncertain factors that could influence the optimal shut down decision. One of these factors is the oil price, as this directly impacts the profits of the project. In this real options model, we treat oil prices as stochastic. Our goal is to establish a starting point for more sophisticated models that can include more uncertain factors. The real options model therefore aims at finding answer to the research question:

- How does uncertainty in oil prices influence the decision to shut down?

This approach is used to estimate the expected shut down time for some chosen fields, which will be compared with the results from the deterministic strategic optimisation model. Moreover, we believe that this approach will provide more realistic answers than the strategic model, and we will be able to set a monetary value of waiting for the option to shut down even though producing in some periods might lead to net losses.

Note that in this case, the option evaluated is the option to permanently shut down the a field only. Temporary shut down and reopening is not taken into account, due to scope limitation of the thesis. We assume that the decision on whether to exercise the option or keeping the option alive is made at the beginning of each period, where one period corresponds to one year. If the option is exercised, the field must be shut down in the same period. We model the option as an American option, as the exercise decision can be made in any point in time. It could have been more reasonable to look at this option as a Bermuda option (where the option can be exercised only at predetermined dates). But since we assume that one period is one year, and that the stochastic variable does not change within this period, we can treat the option as American.

6.2.1 The Stochastic Variable

We assume that the oil price follows a geometric Brownian motion described by the following stochastic differential equation:

$$dX_t = \alpha X_t dt + \sigma X_t dZ_t \tag{6.2.1}$$

Where α is the risk adjusted drift, σ is the volatility, and dZ_t is the increment of a standard Brownian process.

We could have chosen other or several stochastic variables. In terms of scope of this thesis, we believe that it is sufficient to consider only one stochastic variable. The reason why oil price is chosen is based on the hypothesis that the oil price is a crucial factor when an operator decides whether to continue to produce or shut down production. Other uncertain factors include e.g. gas and NGL prices, recoverable resources, technology to increase production, operational costs, policy restrictions, unexpected depletion and uncertainty in P&A costs, but these will not be considered in this model.

6.2.2 Real Options Model Method

We use a Monte Carlo simulation approach in order to obtain different paths the oil price might take during the time horizon. Other approaches, such as the binomial method and Black-Scholes model is deemed as inferior in this case due to the lack of inclusion of adjusted probability of up and down moves in order to be able to use a risk free discount rate, and the inability to calculate the option value's at different points in time, respectively. Parameters for drift α and volatility σ to be used in Equation (6.2.1) given in Table 6.4.

Table 6.4: Estimated price process parameters (Støre et al., 2016)

Parameter	**Estimated Values**	**Standard Error**
α	0.0042	0.0013
σ	0.3380	0.0056

For the simulation of oil prices, we used the following formula for the log-normal price:

$$S_{nh} = S_{(n-1)h} e^{(\alpha - \frac{1}{2}\sigma)h + \sigma\sqrt{h}Z(n)} \tag{6.2.2}$$

Where S_{nh} is the oil price in period n, h is the length of one interval (in this case, $h = 1$ as each period's length is one year) and $Z(n)$ is a normally distributed random variable calculated for period n.

In an American option, we must consider the continuation value based on the fact that at any point in time, future cash flows are uncertain. When deciding whether to exercise an option by looking ahead on the price path, we are using knowledge about the future which is information we will not have in real life. Valuing options this way will give us too high a value (McDonald et al., 2006). To mitigate this look-ahead bias we can base an exercise decision on average outcomes from a given point in time. One way of doing this, and the approach chosen for this thesis, is to use regression to characterise the continuation value based on analysis of multiple paths. We use the approach described in Longstaff and Schwartz (2001): For each point in time, a conditional expectation function is derived from considering the value of the cash flows[1] in a given period as independent variable, and the present value of cash flows for the next period dependent variables. By estimating a conditional expectation function for each exercise period, we can obtain a complete specification of the optimal exercise strategy along each path. We choose a polynomial regression of second order as this is usually provides a good fit for the least squares method:

$$E[X \mid Y] = \beta + \gamma_1 X + \gamma_2 X^2 \tag{6.2.3}$$

Where we treat X as the profits obtained in the given period, and Y is the discounted value of the cash flow obtained in the next period. The following steps are used to obtain the exercise and continuation value as well as the expected optimal shut down time.

[1] In Longstaff and Schwartz (2001), they use stock prices rather than cash flows, but this is not relevant for our purposes.

1. Run 10 000 Monte Carlo simulations of oil prices in accordance with Equation (6.2.1).
2. Calculate the profits obtained in each period for each price path.
3. Begin backtracking:
    (a) Calculate the exercise value for each price path. This is the cost of shut down subtracted the profits received in this period and all future periods.
    (b) Calculate the discounted cash flow for next period for each price path. the cash flow is chosen as the maximum of the exercise value and profits the next period.
    (c) Perform second order polynomial regression on the profits obtained in this period and discounted cash flow from the next period.
    (d) Calculate the value of the conditional expectation function in accordance with Equation (6.2.3) for each price path.
    (e) Compare continuation value and exercise value. The largest value is the cash flow used in calculating the conditional expectation function in the period before the current.
4. Average all expectation and continuation values for each period. Discount all values in order to obtain today's values. The period where the exercise value is higher than the continuation value is interpreted as the expected optimal shut down time.

6.2.3 Choosing Fields to Analyse

Since we are only treating oil prices as stochastic, our real options model is only relevant for fields that produces only oil. We choose to focus on three fields which has approximately the same expected production stop time according to UCube. We chose the following oil producing fields: Brynhild, Svalin and Vigdis.

For future research, the real options model could be extended such that fields producing gas and NGL could be included. Then one should treat the related prices as stochastic, and take into account correlations between prices.

6.3 The Tactical MIP Model

We developed two models for the resource allocation and coordination problem for a medium time horizon (2-5 years). The first one to be presented is a model denoted "the Tactical MIP Model". The second model is named "the Tactical VRP Model". The major difference is that the former handles time periods as discrete, while the latter sees time as continuous (MIP refers to "mixed integer programming" and VRP refers to "Vehicle Routing Problem"). The reason for including both is that the models' performances differ significantly for different scenarios and to show that the same problem can be addressed from different angles. We only choose to proceed with one of these based on a discussion given in Section 6.5.

6.3.1 Problem Description

Solving the tactical model will give insights that might help answering the following research questions.

- How should P&A operations of wells be planned in order to obtain the most efficient use of resources?
- What are the effects of operators cooperating in the planning and execution of P&A activities?
- How can different optimisation models provide answers to these questions?

This problem considers a set of wells that are candidates for P&A during a medium term planning horizon (typically 2-5 years). The decision to be made is whether or not to use a specific vessel for P&A activities on a specific phase on a well. All wellbores must be P&A'ed during the planning horizon. P&A can be executed in any period within the planning horizon. The time resolution for decision is months. We are not considering TP&A here.

P&A phase p must be executed in the same period or later than phase $p-1$ for wellbores that need more than one phase. The last phase executed in a well must be performed in the same period or later than all other phases for wellbores in this well.

Each time a specific vessel visits a field, a fixed mobilisation cost is incurred. In order to correctly record transportation between locations, we assume that a vessel cannot be present at more than one location in the same month. If a vessel is used for either transport or execution of P&A, a daily rental cost is incurred for the days where the vessel is in use and the same cost incurs if the vessel is idle and present in a field. If a vessel is not present in any field, it has to be situated in a dummy field, which can be interpreted as a port, where no costs incur.

Wait on Weather (WOW) is considered in this model. For P&A activities during spring and autumn, the duration of the activities increases compared to the summer months. For activities during winter, the WOW factor is even larger. WOW is also included for transportation of vessels.

The objective is to minimise the costs associated with the use of vessels to perform P&A activities, idle time cost, travel time cost and mobilisation cost in a planning horizon of 2-5 years with discrete time resolution in months. The output will be a medium term plan for P&A on the NCS.

6.3.2 Model Assumptions

- All vessels are available for P&A any time in the planning horizon, unless they are used for P&A of other wells.
- All wells in the planning horizon must be P&A'ed.
- Only permanent P&A is considered.
- If a vessel is not used in a field, the vessel must be present in a port where no cost incurs.
- Mobilisation costs are fixed and independent on distance and time periods. We assume that most of the mobilisation costs are related to the actual transportation and thus captured by the rental cost for the period in which the vessel is moving.
- A vessel can be present in only one location in a given time period.
- Time periods are discrete, but durations of activities are continuous.
- For each wellbore, execution of a new phase can start immediately after the previous phase has been executed. A vessel can be transported immediately after it has completed its operations on a well.
- We have not included non-productive time in the calculation of durations.
- Travel time between wells within the same field is 0.
- The only resources required for P&A operations are vessels.

6.3.3 Sets

In this model, a new set $\mathcal{F}^W$ consisting of the all fields in $\mathcal{F}$, that are associated with wellbores that are candidates for P&A and require mobilisation of vessels is introduced. We also create a set $\mathcal{F}^D$ that represent a dummy field at which a vessel can be present without incurring any costs. This dummy field can be interpreted as a location in which the vessels are not used for P&A purposes, such as a port.

We let $\mathcal{B}$ be the set of types (subsea or platform) of wellbores, and $\mathcal{B}_f \subseteq \mathcal{B}$ the set of types of wellbores present in field $f \in \mathcal{F}^W$.

The set $\mathcal{W}$ is the set of wells that require P&A, and $\mathcal{WB}$ the wellbores that require P&A. Further, we create a subset $\mathcal{WB}_a$ that includes the wellbores in well $a \in \mathcal{W}$. The set $\mathcal{WB}$ is further divided in three subsets: $\mathcal{WB}_{fb}$ is the set of wellbores in field f of type b that requires P&A. The second subset, $\mathcal{WB}_{fb}^{P12}$, consists of wellbores that need phase 1 and 2 (and 3 if subsea well). If a well consist of one wellbore only that need all three phases (four phases for subsea wellbores), the wellbore is also included in $\mathcal{WB}_{fb}^{P12}$. The third subset of $\mathcal{WB}$ is $\mathcal{WB}_{fb}^{P4}$ and includes the wellbores that require the last phase. Let $\mathcal{P}$ be the set of phases, and $\mathcal{P}_i$ be the set of phases required for wellbore i and $\mathcal{T}$ denote the set of time periods in the planning horizon. Further, let $\mathcal{Y}$ and $\mathcal{M}$ denote the years and months, respectively. The set $\mathcal{T}_{ym}$ is the time periods that correspond to year y and month m.

The vessels are included in the set $\mathcal{R}$. Let $\mathcal{R}_b$ be the set of vessels appropriate for wellbores of type b, and $\mathcal{R}_{bp}$ be the sets of vessels appropriate for wellbore of type b and phase p. All sets are summarised in Table 6.5.

Table 6.5: Sets in the tactical MIP model

Set	Description
$\mathcal{F}$	Fields including dummy fields
$\mathcal{F}^W$	Fields
$\mathcal{F}^D$	Dummy fields
$\mathcal{B}$	Wellbore types
$\mathcal{B}_f$	Wellbore types present in field f
$\mathcal{W}$	Wells that requires P&A
$\mathcal{WB}$	Wellbores that requires P&A
$\mathcal{WB}_a$	Wellbores in well a
$\mathcal{WB}_{fb}$	Wellbores in field f and type b that require P&A
$\mathcal{WB}_{fb}^{P12}$	Wellbores requiring phases 1 and 2 (and 3 for subsea wellbores)
$\mathcal{WB}_{fb}^{P4}$	Wellbores that need phase 4
$\mathcal{P}$	Phases of the P&A process
$\mathcal{P}_i$	Phases in well i
$\mathcal{T}$	Time periods in planning horizon
$\mathcal{Y}$	Years in planning horizon
$\mathcal{M}$	Months in year
$\mathcal{T}_{ym}$	Time period corresponding to year y and month m
$\mathcal{R}$	Vessels
$\mathcal{R}_b$	Vessels appropriate for type b
$\mathcal{R}_{bp}$	Vessels appropriate type b and phase p

6.3.4 Parameters

Let T_{ipkt}^{EX} be the duration a vessel k needs to execute phase p on well i in time period t. T_{fzkt}^{TR} is the travel time for vessel k between fields f og z in time period t. We use the time index to include the WOW factors. C_k^R denotes the daily rental rate of vessel k. C_k^{MOB} reflects the fixed mobilisation cost for vessel k. If a field is being P&A'ed in a year that deviates from the optimal year found in the strategic model, a change costs C_{fy}^C is incurred. D is the number of days in one time period, and T is the number of time periods. All parameters are listed in Table 6.6

Table 6.6: Parameters in the tactical MIP model

Parameter	**Description**
T^{EX}_{ipkt}	Execution time in days
T^{TR}_{fzkt}	Travel time between fields
C^{R}_{k}	Daily rate of vessel
C^{MOB}_{f}	Mobilisation cost of vessel
C^{C}_{fy}	Changing cost
D	Days in time period
T	Number of time periods

6.3.5 Variables

Use of a specific vessel k to execute P&A phase p on well i at time t is given by the binary variable r_{ipkt}. It takes the value 1 at the time when the execution starts, and 0 otherwise. In order to capture the mobilisation and transport of vessels, two variables are introduced: γ_{fkt} is binary and 1 if vessel k is located in location f at time t, and 0 otherwise. If a vessel arrives at a field f after being located at another field z, the binary variable θ_{zfkt} takes the value 1, and is 0 otherwise. In order to account for the costs of deviating from optimal shut down time, we need the binary variable λ_{fy} which is 1 if P&A operations in field f is being performed in year y, and 0 otherwise.

In order to take into consideration time feasibility, we need to count the days during the month in which a vessel is used, and the days where the vessel is idle. We let ω_{kt} be the number of days a vessel k is used in time period t, and i_{kt} the number of days a vessel k is idle in period t. We need an auxiliary binary variable ϕ_{kt} to connect ω_{kt} and i_{kt}, which is 1 if a vessel k is used in period t and 0 otherwise. We also need a variable counting the days of the total P&A durations in a well within a month. Let w_{at} be the total duration in days of P&A activities in well $a \in \mathcal{W}$ in period t. All variables are listed in Table 6.7.

Table 6.7: Variables in the tactical MIP model

Variable	Description
r_{ipkt}	Start time of P&A
γ_{fkt}	Vessel location
θ_{zfkt}	Movement of vessel
λ_{fy}	Year of P&A
ω_{kt}	Number of days a vessel is used in a period
i_{kt}	Number of days a vesselis idle in a period
ϕ_{kt}	Auxiliary variable connecting ω_{kt} and i_{kt}
w_{at}	Total duration of P&A operations in a well in one period

6.3.6 Constraints

In this section, we present all constraints that apply for the tactical MIP model.

Vessel use

All phases in all wellbores in the planning horizon must be P&A'ed by exactly one vessel. This is ensured by Constraints (6.3.1):

$$\sum_{k \in \mathcal{R}_{bp}} \sum_{t \in \mathcal{T}} r_{ipkt} = 1, \qquad \forall f \in \mathcal{F}^W, b \in \mathcal{B}_f, i \in \mathcal{WB}_{fb}, p \in \mathcal{P}_i \tag{6.3.1}$$

Sequencing

Constraints (6.3.2) guarantee that wellbores that need phases 1 and 2 (and 3 for subsea wellbores) is executed in increasing phase order:

$$\sum_{k \in \mathcal{R}_{bp}} \sum_{\tau = t}^{T} r_{ipk\tau} - \sum_{k \in \mathcal{R}_{bq}} r_{iqkt} \geq 0,$$
$$\forall f \in \mathcal{F}^W, b \in \mathcal{B}_f, i \in \mathcal{WB}_{fb}^{P12}, (p,q) \in \mathcal{P}_i \mid p > q, t \in \mathcal{T} \tag{6.3.2}$$

The last phase in a well must be executed after the previous phases of all wellbores in the same well. This is handled by Constraints (6.3.3):

$$\sum_{k \in \mathcal{R}_{bp}} \sum_{\tau=t}^{T} r_{ipk\tau} - \sum_{k \in \mathcal{R}_{bq}} r_{jqkt} \geq 0,$$
$$\forall f \in \mathcal{F}^W, b \in \mathcal{B}_f, a \in \mathcal{W}, i \in \mathcal{WB}_{fb}^{P4} \cap \mathcal{WB}_a,$$
$$j \in \mathcal{WB}_{fb}^{P12} \cap \mathcal{WB}_a, p \in \mathcal{P}_i, q \in \mathcal{P}_j \mid p > q, t \in \mathcal{T} \tag{6.3.3}$$

Time constraints

Constraints (6.3.4) records the total number of days used for P&A in well a in time period t:

$$\sum_{p \in \mathcal{P}_j} \sum_{k \in \mathcal{R}_{bp}} T_{jpkt}^{EX} r_{jpkt} + \sum_{k \in \mathcal{R}_{b4}} T_{i4kt}^{EX} r_{i4kt} = w_{at},$$
$$\forall f \in \mathcal{F}^W, b \in \mathcal{B}_f, a \in \mathcal{W}, i \in \mathcal{WB}_{fb}^{P4} \cap \mathcal{WB}_a, j \in \mathcal{WB}_{fb}^{P12} \cap \mathcal{WB}_a, t \in \mathcal{T} \tag{6.3.4}$$

Constraints (6.3.5) records the total number of days a vessel is used for P&A purposes during a time period:

$$\sum_{f \in \mathcal{F}^W} \sum_{i \in \mathcal{WB}_{fb}} \sum_{p \in \mathcal{P}_i} T_{ipkt}^{EX} r_{ipkt} + \sum_{\substack{(f,z) \in \mathcal{F} \\ f \neq z}} T_{fzkt}^{TR} \theta_{fzkt} = \omega_{kt},$$
$$\forall b \in \mathcal{B}, k \in \mathcal{R}, t \in \mathcal{T} \tag{6.3.5}$$

If a vessel is used in a period, the number of days it is not used for P&A purposes or travel time is idle time. This idle time is recorded by Constraints (6.3.6).

$$\omega_{kt} = D\phi_{kt} - i_{kt}, \qquad \forall k \in \mathcal{R}, t \in \mathcal{T} \tag{6.3.6}$$

In addition to these constraints, we refer to the variable declarations (6.3.15), (6.3.17), and (6.3.18).

Vessel location

The same vessel cannot be present at several locations during the same time period. Constraints (6.3.6) ensure that a vessel is present at one and only one location in each time period:

$$\sum_{f \in \mathcal{F}} \gamma_{fkt} = 1, \qquad \forall k \in \mathcal{R}, t \in \mathcal{T} \tag{6.3.7}$$

Constraints (6.3.8) ensure that γ_{fkt} takes the value 1 if the vessel k is used to execute phase p on wellbore i at time t:

$$\gamma_{fkt} \geq r_{ipkt}, \qquad \forall f \in \mathcal{F}^W, b \in \mathcal{B}_f, i \in \mathcal{WB}_{fb}, p \in \mathcal{P}_i, k \in \mathcal{R}_{bp}, t \in \mathcal{T} \tag{6.3.8}$$

We also have to make sure that resource use is recorded even though no transportation or P&A operations are being executed. This is to ensure that if a vessel is present in a field and no activity occurs, idle time costs should incur. This is handled by Constraints (6.3.9):

$$\gamma_{fkt} - \phi_{kt} \leq 0, \qquad \forall f \in \mathcal{F}^W, k \in \mathcal{R}, t \in \mathcal{T} \tag{6.3.9}$$

In order to ensure that θ_{fzkt} takes its appropriate value, we need Constraints (6.3.10), which states that if a vessel's location changes, a move between the locations must be recorded:

$$\begin{aligned} &\gamma_{fkt} + \gamma_{zkt-1} - \theta_{zfkt} - \theta_{zfkt-1} \leq 1, \\ &\forall (f, z) \in \mathcal{F} \mid f \neq z, k \in \mathcal{R}, t \in \mathcal{T} \end{aligned} \tag{6.3.10}$$

Note that the movement can be performed in either of the periods t and $t-1$.

Changing P&A year

If a P&A operation is performed in a wellbore in a time period that correspond to a year that deviates from the optimal shut down time of the field in which the wellbore is located, a change cost incurs. In order to record this change in P&A years, we need Constraints (6.3.11):

$$\sum_{i\in\mathcal{WB}_{fb}}\sum_{p\in\mathcal{P}_i}\sum_{k\in\mathcal{R}_{bp}}\sum_{m\in\mathcal{M}}\sum_{t\in\mathcal{T}_{ym}} r_{ipkt} - D\lambda_{fy} \leq 0,$$
$$\forall f \in \mathcal{F}^W, b \in \mathcal{B}_f, y \in \mathcal{Y} \tag{6.3.11}$$

Note that we use D as a "big M" formulation, as we know that the leftmost sum cannot exceed D due to constraints (6.3.4), and the restriction on the domain of w_{at} given in Constraints (6.3.18)

Variable declarations

Constraints (6.3.12) - (6.3.19) declare the variables used in the tactical MIP model.

$$r_{ipkt} \in \{0,1\}, \quad \forall f \in \mathcal{F}^W, b \in \mathcal{B}_f, i \in \mathcal{WB}_{fb}, p \in \mathcal{P}_i, k \in \mathcal{R}_{bp}, t \in \mathcal{T}, \tag{6.3.12}$$
$$\gamma_{fkt} \in \{0,1\}, \quad \forall f \in \mathcal{F}, k \in \mathcal{R}, t \in \mathcal{T}, \tag{6.3.13}$$
$$\theta_{fzkt} \in \{0,1\}, \quad \forall (f,z) \in \mathcal{F} \mid f \neq z, b \in \mathcal{B}, k \in \mathcal{R}, t \in \mathcal{T}, \tag{6.3.14}$$
$$0 \leq \omega_{kt} \leq D, \quad \forall k \in \mathcal{R}, t \in \mathcal{T} \tag{6.3.15}$$
$$0 \leq i_{kt} \leq D, \quad \forall k \in \mathcal{R}, t \in \mathcal{T} \tag{6.3.16}$$
$$\phi_{kt} \in \{0,1\}, \quad \forall k \in \mathcal{R}, t \in \mathcal{T} \tag{6.3.17}$$
$$0 \leq w_{at} \leq D, \quad \forall a \in \mathcal{W}, t \in \mathcal{T} \tag{6.3.18}$$
$$\lambda_{fy} \in \{0,1\}, \quad \forall f \in \mathcal{F}^W, y \in \mathcal{Y} \tag{6.3.19}$$

6.3.7 Objective Function

The objective function (6.3.20) is a minimisation function that minimises the costs associated with P&A operations on wellbores .

$$\begin{aligned} min \sum_{f\in\mathcal{F}^W}\sum_{b\in\mathcal{B}_f}\sum_{i\in\mathcal{WB}_{fb}}\sum_{p\in\mathcal{P}_i}\sum_{k\in\mathcal{R}_{bp}}\sum_{t\in\mathcal{T}} C_k^R T_{ipkt}^{EX} r_{ipkt} \\ + \sum_{\substack{(f,z)\in\mathcal{F}\\ f\neq z}}\sum_{k\in\mathcal{R}}\sum_{t\in\mathcal{T}} C_k^{MOB}\theta_{zfkt} + \sum_{\substack{(f,z)\in\mathcal{F}\\ f\neq z}}\sum_{k\in\mathcal{R}}\sum_{t\in\mathcal{T}} C_k^R T_{zfkt}^{TR}\theta_{zfkt} \\ + \sum_{k\in\mathcal{R}}\sum_{t\in\mathcal{T}} C_k^R i_{kt} + \sum_{f\in\mathcal{F}^W}\sum_{y\in\mathcal{Y}} C_{fy}^C \lambda_{fy} \end{aligned} \tag{6.3.20}$$

The tactical MIP problem is thus given by Constraints (6.3.1) - (6.3.19) and the objective function (6.3.20).

6.4 The Tactical VRP Model

The tactical VRP problem is based on the RCPSP and VRPTW presented in Chapter 3, sections 3.4.1 sections 3.4.2. The problem description for this VRP problem is the same as for the MIP problem. Many of the sets, indices and parameters will be the same. Therefore, we only present the notation that is specific for the VRP problem. We need to change some of the model assumptions, however.

6.4.1 Model Assumptions

- All vessels are available for P&A any time in the planning horizon.
- All wellbores in the planning horizon must be P&A'ed
- Only permanent P&A is considered.
- Mobilisation costs are fixed and independent on distance and time periods. We assume that most of the mobilisation costs are related to the actual transportation and thus captured by the rental cost for the period in which the vessel is moving.
- For each wellbore, execution of a new phase can start immediately after the previous phase has been executed. A vessel can be transported immediately after it has completed its operations on a well.
- If a vessel is not used in a field, the vessel must be present in a port where no cost incurs.
- A vessel can visit the port only a predetermined number of times during the planning period.
- We have not included non-productive time or WOW factor in the of durations parameters.
- Time is continuous.
- Travel time between wells within the same field is 0.
- The only resources needed to perform the P&A operations are vessels.

6.4.2 Sets

In this model, in addition of modelling dummy fields, we include modelling of dummy wells. These are present in the set of dummy wells $\mathcal{D}$. Let $\mathcal{B}^D$ be the dummy types for dummy nodes. For each dummy well, there are a set of dummy phases $\mathcal{P}^D$. The reason for including these dummy sets is that by using the VRP approach, it is simpler to ensure time feasibility if we constrain arcs to go in and out of each node only once. Let $\mathcal{L}$ be the set of locations, including wellbores and dummy wells, and $\mathcal{L}_{fb}$ be the set of locations associated with field $f \in \mathcal{F}$ and type $b \in \mathcal{B}$. Note that we omit the set $\mathcal{T}$ as this model assumes time as continuous rather than discrete. Table 6.8 lists the specific sets used in this model. We also make use of many of the sets listed in 6.5, but these are not mentioned here.

Table 6.8: Specific sets in the tactical VRP model

Set	**Description**
$\mathcal{D}$	Dummy wells
$\mathcal{B}^D$	Dummy types for dummy nodes in dummy field
$\mathcal{L}$	Locations, including wellbores and dummy wells
$\mathcal{L}_{fb}$	Locations associated with field f and type b
$\mathcal{P}^D$	Dummy phases in dummy wells

6.4.3 Parameters

Let the duration of P&A operation associated with phase p on wellbore i performed by resource k be given by the parameter T^{EX}_{ipk}, and travel time between fields f and z by T^{TR}_{zfk}. For all other parameters used in this model, we refer to Table 6.6.

Table 6.9: Specific parameters in the tactical VRP model

Parameter	**Description**
T^{EX}_{ipk}	Execution time
T^{TR}_{zfk}	Travel time

6.4.4 Variables

s_{ipk} is a non-negative variable denoting the execution start time of phase p on wellbore i performed by resource k. Note that only one resource can execute one phase on a particular wellbore. This means that $\sum_{k \in \mathcal{R}} s_{ipk}$ is present in a special ordered set 1 (SOS1). We will use a binary variable q_{ipk} to ensure this. We only create the variables if resource k can be used for executing the relevant phases. x_{ipjqk} is a binary variable that takes the value 1 if vessel k is transported from location i after executing phase p, to location j to execute phase q, and 0 otherwise. As phases in the same wellbore and well do not require actual physical movement of the vessel if these phases are executed consecutively by the same vessel without the vessel being used for other purposes between these phases, an artificial transportation arc is constructed with no associated cost or duration. α_{ipjqk} is a variable that records at what time vessel k exits a dummy node (i, p) to location j to execute phase q. β_{ipjqk} records the time when vessel k enters a dummy node (j, q) after executing phase p on wellbore i. These variables are used to calculate the total number of days a vessel is use. All variables are listed in Table 6.10.

Table 6.10: Variables in the tactical VRP problem

Variable	**Description**
s_{ipk}	Start time of execution of a phase
q_{ipk}	1 if a vessel is used for execution of a phase
x_{ipjqk}	Transportation arc
α_{ipjqk}	Time when a vessel leaves a dummy node
β_{ipjqk}	Time when vessel arrives at dummy node

6.4.5 Constraints

In the following section, all constraints in the tactical VRP problem will presented.

Sequencing

We make sure that for all wellbores that require phases 1 and 2 (and 3 for subsea wellbores), the sequence of phases follow in increasing order. This is ensured by Constraints (6.4.1):

$$s_{ipk} - s_{iqk} \geq T^{EX}_{ipk}, \qquad \forall i \in \mathcal{WB}, (p, q) \in \mathcal{P}_i \mid p > q, k \in \mathcal{R} \tag{6.4.1}$$

Also, phase 4 must be executed after all other phases in all other wellbores in the same well. Constraints (6.4.2) ensure this.

$$\sum_{k \in \mathcal{R}} s_{i4k} - \sum_{k \in \mathcal{R}} s_{jp} \geq 1,$$
$$\forall a \in \mathcal{W}, i \in \mathcal{WB}_a \cap \mathcal{WB}^{P4}, j \in \mathcal{WB}_a \cap \mathcal{WB}^{P12}, p \in \mathcal{P}_j \qquad (6.4.2)$$

To model the variables $\sum_{k \in \mathcal{R}} s_{ipk}$ as part of SOS1, we include Constraints (6.4.3) and (6.4.4):

$$s_{ipk} - Dq_{ipk} \leq 0, \qquad \forall f \in \mathcal{F}^W, b \in \mathcal{B}_f, i \in \mathcal{WB}, p \in \mathcal{P}_i, k \in \mathcal{R}_{bp} \qquad (6.4.3)$$

$$\sum_{k \in \mathcal{R}_{bp}} q_{ipk} = 1, \qquad \forall f \in \mathcal{F}^W, b \in \mathcal{B}_f, i \in \mathcal{WB}, p \in \mathcal{P}_i \qquad (6.4.4)$$

P&A of all wellbores

We must make sure that all phases in all wellbores are being visited by one of the appropriate vessels. This is done by attaching arcs to each node pair (i, p), (j, q) in Constraints (6.4.5):

$$\sum_{f \in \mathcal{F}} \sum_{b \in \mathcal{B}_f} \sum_{i \in \mathcal{L}_{bf}} \sum_{p \in \mathcal{P}_i} \sum_{k \in \mathcal{R}_{bp}} x_{ipjqk} = 1, \qquad \forall j \in \mathcal{WB}, q \in \mathcal{P}_j \qquad (6.4.5)$$

Flow balance

If an arc enters a node, it must leave from the same node. This is handled by Constraints (6.4.6).

$$\sum_{i \in \mathcal{L}} \sum_{p \in \mathcal{P}_i} x_{ipjqk} - \sum_{i \in \mathcal{L}} \sum_{p \in \mathcal{P}_i} x_{jqipk} = 0,$$
$$\forall f \in \mathcal{F}, b \in \mathcal{B}_f, j \in \mathcal{WB}_{fb}, q \in \mathcal{P}_j, k \in \mathcal{R}_{bp} \qquad (6.4.6)$$

Dummy node constraints

When modelling the arcs in and out of dummy nodes, we must ensure that these nodes are entered and exited no more than once by the same vessel. Constraints (6.4.7) and (6.4.8) guarantee this.

$$\sum_{j \in \mathcal{WB}} \sum_{q \in \mathcal{P}_j} x_{jqipk} \leq 1, \qquad \forall i \in \mathcal{D}, p \in \mathcal{P}^D \mid p > 1, k \in \mathcal{R} \tag{6.4.7}$$

$$\sum_{j \in \mathcal{WB}} \sum_{q \in \mathcal{P}_j} x_{ipjqk} \leq 1, \qquad \forall i \in \mathcal{D}, p \in \mathcal{P}^D \mid p < |\mathcal{P}^D|, k \in \mathcal{R} \tag{6.4.8}$$

Since we are operating with arcs that only go in and out of a node once, we must make sure that if a vessel exits a dummy node, it must enter the next dummy node at some later point in time. Similarly, we must ensure that if a vessel exits a dummy node, it must have completed the previous dummy phase. These two restrictions are handled in Constraints (6.4.9) and (6.4.10), respectively.

$$\sum_{j \in \mathcal{WB}} \sum_{q \in \mathcal{P}_j} x_{jqipk} - \sum_{j \in \mathcal{WB}} \sum_{q \in \mathcal{P}_j} x_{ip-1jqk} \geq 0,$$
$$\forall i \in \mathcal{D}, p \in \mathcal{P}^D \mid p \geq 2, k \in \mathcal{R} \tag{6.4.9}$$

$$\sum_{j \in \mathcal{WB}} \sum_{q \in \mathcal{P}_j} x_{ipjqk} - \sum_{j \in \mathcal{WB}} \sum_{q \in \mathcal{P}_j} x_{jqip+1k} = 0,$$
$$\forall i \in \mathcal{D}, p \in \mathcal{P}^D \mid p < |\mathcal{P}^D|, k \in \mathcal{R} \tag{6.4.10}$$

Time constraints

If a vessel enters a dummy node, it must enter after the previous P&A operation is completed and the travel time from the field in which the wellbore is located to the dummy node. This is handled by Constraints (6.4.11):

$$s_{ipk} + T^{EX}_{ipk} + T^{TR}_{fzk} - \beta_{ipjqk} \leq D(1 - x_{ipjqk})$$
$$\forall f \in \mathcal{F}^W, b \in \mathcal{B}_f, i \in \mathcal{WB}_{fb}, p \in \mathcal{P}_i,$$
$$z \in \mathcal{F}^D, c \in \mathcal{B}^D, j \in \mathcal{D}, q \in \mathcal{P}^D \mid q > 1, k \in \mathcal{R}_{bp} \cap \mathcal{R}_{cq} \tag{6.4.11}$$

Then, Constraints (6.4.12) record the time a vessel leaves a dummy node, which must happen before the P&A operation of which the vessel is to perform start and the travel time to the field in which the wellbore is located:

$$\alpha_{ipjqk} - T^{TR}_{fzk} - s_{jqk} \leq 1 - x_{ipjqk},$$
$$\forall f \in \mathcal{F}^D, b \in \mathcal{B}^D, i \in \mathcal{D}, p \in \mathcal{P}^D \mid p < |\mathcal{P}^D|,$$
$$z \in \mathcal{F}^W, c \in \mathcal{B}_z, j \in \mathcal{WB}_{zc}, q \in \mathcal{P}_j, k \in \mathcal{R}_{bp} \cap \mathcal{R}_{cq} \tag{6.4.12}$$

We must also make sure that α_{ipjqk} takes the value 0 if the vessel is not exiting a dummy node. This is ensured by Constraints (6.4.13).

$$\alpha_{ipjqk} - T^{TR}_{fzk} x_{ipjqk} \leq 0,$$
$$\forall f \in \mathcal{F}^D, b \in \mathcal{B}^D, i \in \mathcal{D}, p \in \mathcal{P}^D \mid p < |\mathcal{P}^D|,$$
$$z \in \mathcal{F}^W, c \in \mathcal{B}_z, j \in \mathcal{WB}_{zc}, q \in \mathcal{P}_j, \mathcal{R}_{bp} \cap \mathcal{R}_{cq} \tag{6.4.13}$$

Finally, we make sure that the same vessel that enters and exits the same dummy node must exit after it has entered the dummy node, which is handled by Constraints (6.4.14):

$$\sum_{j \in \mathcal{WB}} \sum_{q \in \mathcal{P}_j} \alpha_{ipjqk} - \sum_{j \in \mathcal{WB}} \sum_{q \in \mathcal{P}_j} \beta_{jqipk} \geq 0,$$
$$\forall i \in \mathcal{D}, p \in \mathcal{P}^D \mid 1 < p < |\mathcal{P}^D|, k \in \mathcal{R} \tag{6.4.14}$$

Variable declarations

Constraints (6.4.15)-(6.4.18) declare the variables used in the tactical VRP model.

$$0 \leq s_{ipk} \leq D, \quad \forall f \in \mathcal{F}^W, b \in \mathcal{B}_f, i \in \mathcal{WB}_{fb}, p \in \mathcal{P}_i, k \in \mathcal{R}_{bp} \tag{6.4.15}$$

$$x_{ipjqk} \in \{0,1\}, \quad \forall f \in \mathcal{F}, b \in \mathcal{B}_f, i \in \mathcal{L}_{fb}, p \in \mathcal{P}_i,$$
$$z \in \mathcal{Z}, c \in \mathcal{B}_z, j \in \mathcal{L}_{zc}, q \in \mathcal{P}_j, k \in \mathcal{R}_{bp} \cap \mathcal{R}_{zc} \tag{6.4.16}$$

$$\beta_{ipjqk} \geq 0, \forall \quad f \in \mathcal{F}^W, b \in \mathcal{B}_f, i \in \mathcal{WB}_{fb}, p \in \mathcal{P}_i,$$
$$j \in \mathcal{D}, q \in \mathcal{P}^D, k \in \mathcal{R}_{bp}, \tag{6.4.17}$$

$$\alpha_{ipjqk} \geq 0, \quad \forall i \in \mathcal{D}, p \in \mathcal{P}^D, f \in \mathcal{F}^W, b \in \mathcal{B}_f,$$
$$j \in \mathcal{W}_{fb}, q \in \mathcal{P}_j, k \in \mathcal{R}_{bq} \tag{6.4.18}$$

6.4.6 Objective Functon

The objective function (6.4.19) minimises the rental and mobilisation costs. Note that we have not chosen to distinguish between idle time costs and operation costs here. We did not find this distinction valuable for the purpose of comparing the models.

The objective function minimises the cost associated with the total time a vessel is outside a dummy node, i.e. the total rental cost, and mobilisation costs.

$$min \sum_{f\in\mathcal{F}^W}\sum_{b\in\mathcal{B}_f}\sum_{i\in\mathcal{WB}_{fb}}\sum_{p\in\mathcal{P}_i}\sum_{z\in\mathcal{F}^D}\sum_{c\in\mathcal{B}^D}\sum_{j\in\mathcal{D}}\sum_{q\in\mathcal{P}^D}\sum_{k\in\mathcal{R}_{bp}} C_k^R\Big[\beta_{ipjqk}-\alpha_{jqipk}\Big] + \sum_{(i,j)\in\mathcal{L}}\sum_{(p,q)\in\mathcal{P}}\sum_{k\in\mathcal{R}} C_k^{MOB}x_{ipjqk} \quad (6.4.19)$$

Thus, Constraints (6.4.1) - (6.4.18) and objective function (6.4.19) represents the tactical VRP problem.

6.5 Discussion on the Tactical Models

Before discussing the different tactical models, it is important to inform that the tactical MIP model was first developed with a time resolution in days. The comparison between the models are based on a test case where we used a time horizon of one year and time resolution in days (for the MIP model), and only a few wellbores. This means that we tested the models actually on a more operational level than tactical.

The reason why both models were developed was based on a hypothesis that dependent on the time horizon, the models would perform computationally differently, and for our purpose, it was difficult in foresight to determine which model would be the most appropriate for our case study. Moreover, it is valuable to investigate different model type's appropriateness for different problem types.

The following observations were made after analysing the performances of the models:

- With high time resolution (days) combined with a time horizon of one year and very few wells, the VRP model performed best. This is not surprising, as the VRP model treats time as continuous and the MIP model treats time as discrete.

- If a more realistic number of wellbores were considered, the MIP model performed best. This is expected, as the number of binary variables increase more in the VRP model than in the MIP model.
- It was easier to include time dependent considerations to the MIP model, such as WOW factors.
- Introducing dummy nodes in the VRP problem introduces a problem if we want to allow vessels to discontinue P&A and be used for other purposes many times during the planning horizon, as we need to set an upper limit on how many times a vessel can enter and exit a dummy field.
- The MIP model is more flexible in terms of alternating between different time resolutions and time horizons.

In general, we found that the MIP model was more suited for a time horizon of several years, as we easily could change the time resolution in such a way that if we extended the time horizon and included more wellbores, the change in problem size was not that big compared with the change in problem size for the tactical VRP problem. Therefore, we chose to use the MIP approach when developing a tactical model with longer time horizon and lower time resolution.

Learning that that the MIP model performed better on a higher time resolution, we chose to continue with the MIP approach when establishing an operational model. Therefore, we discarded the VRP model for the remainder of this thesis.

6.6 The Operational Model

In this section, the operational model is presented.

6.6.1 Problem Description

The operational model is established to find answers to the following research questions:

- How should P&A operations of wells be planned in order to obtain the most efficient use of resources?
- What are the effects of operators cooperating in the planning and execution of P&A activities?
- How can different optimisation models provide answers to these questions?

We are considering a time resolution in days, and the decisions to be made are the start dates for operations and how vessels should move between fields and the port in a cost optimal way in a short time horizon.

When a vessel is used for a P&A activity, it must be present at the respective location for the total duration of the activity, i.e. no other P&A operation performed by the same vessel nor any movement of the vessel can be conducted during the course of the P&A operation. When an activity, either P&A operation or movement, begins, we assume that the entire start day is available for the operation. When an activity is finished, a new activity cannot start until the day after. We are assuming that there are no non-productive time and that a phase in the P&A operation or movement to another location can start one day after a previous phase is completed, without any waiting time.

The only periods in which the rental cost incur are the days where a vessel is present in a field and during the travel time between locations. Durations are in fractional values, so in order to use the durations in combination with a discretisation of time, we round all duration values up to the nearest integer. The reason why we do not round these values to nearest integer is to avoid that some durations take the value 0. In addition, we believe that this can reflect the fact that there might be delays in the different activities.

The objective is to minimise the rental costs of the vessels used for P&A operations and fixed mobilisation cost of travelling between locations. The output will be a day-to-day schedule of P&A operations on a short time horizon.

6.6.2 Model Assumptions

- All vessels are available for P&A any time in the planning horizon.
- All wellbores in the planning horizon must be P&A'ed.
- Only permanent P&A is considered.
- If a vessel is not used in a field, the vessel must be present in a port where no cost incurs.
- Mobilisation costs are fixed and independent on distance and time periods.
- A vessel can be present in only one location in a given time period (days).
- Time periods and durations are discrete. The latter is rounded up to nearest integer.

- For each wellbore, execution of a new phase can start one day after the previous phase has been executed.
- There is no waiting time between the different activities.
- Non-productive time is not included explicitly.
- If an activity starts in a given day, the WOW factor prevailing at the start date is used for all days during the activity period, even though another WOW factor may be prevailing at the end date.
- A vessel's transport back to the port might end in a day later than the time horizon. However, the rental cost incurs also in this period.
- The travel time between wells in the same field is 0.
- The only resources required for P&A operations are vessels.

6.6.3 Sets, Parameters and Variables

In the operational model, we use the same sets, parameters and variables as in the tactical model, as given in tables 6.5, 6.6 and 6.7, respectively. However, we do not use all of these in the operational model, and the parameters for durations, i.e. T^{EX}_{ipkt} and T^{TR}_{fzkt} are rounded up to nearest integer, but we use the same notation.

6.6.4 Constraints

In this section, all constraints in the operational model will be presented. Note that some of the constraints presented here might be similar to the ones presented for the tactical MIP model.

Resource use

All phases in all wellbores must be P&A'ed by exactly one vessel. This is ensured by Constraints (6.6.1):

$$\sum_{k \in \mathcal{R}_{bp}} \sum_{t \in \mathcal{T}} r_{ipkt} = 1, \qquad \forall f \in \mathcal{F}^W, b \in \mathcal{B}_f, i \in \mathcal{WB}_{fb}, p \in \mathcal{P}_i \tag{6.6.1}$$

Sequencing

All phases in a wellbore must be executed in increasing order. Constraints (6.6.2) make sure that all phases 1-3 is perfomed in sequence, and Constraints (6.6.3) make sure that phase 4 of the initial well is executed after all other phases in all other wellbores in that well are completed. Note that the parameter T now denotes number of days, and the set $\mathcal{T}$ is the set of days, rather than months.

$$\sum_{k \in \mathcal{R}_{bp}} \sum_{\tau=t+1}^{T} r_{ipk\tau} - \sum_{k \in \mathcal{R}_{bq}} r_{iqkt} \geq 0,$$

$$\forall f \in \mathcal{F}^W, b \in \mathcal{B}_f, i \in \mathcal{WB}_{fb}^{P12}, (p,q) \in \mathcal{P}_i \mid p > q, t \in \mathcal{T} \tag{6.6.2}$$

$$\sum_{k \in \mathcal{R}_{bp}} \sum_{\tau=t+1}^{T} r_{ipk\tau} - \sum_{k \in \mathcal{R}_{bq}} r_{jqkt} \geq 0,$$

$$\forall f \in \mathcal{F}^W, b \in \mathcal{B}_f, a \in \mathcal{W}, i \in \mathcal{WB}_{fb}^{P4} \cap \mathcal{WB}_a,$$

$$j \in \mathcal{WB}_{fb}^{P12} \cap \mathcal{WB}_a, p \in \mathcal{P}_i, q \in \mathcal{P}_j \mid p > q, t \in \mathcal{T} \tag{6.6.3}$$

Vessel at one location in same time period

The same vessel cannot be present at several location in the same time period. Constraints (6.6.4) guarantee this:

$$\sum_{a} r_{iqc\tau} + \sum_{b} r_{jqk\tau} + \sum_{c} \theta_{vzk\tau} \leq T_{ipkt}^{EX}\Big(1 - r_{ipkt}\Big)$$

$$\forall f \in \mathcal{F}^W, b \in \mathcal{B}_f, i \in \mathcal{WB}_{fb}, p \in \mathcal{P}_i, k \in \mathcal{R}_{bp}, t \in \mathcal{T} \tag{6.6.4}$$

The summations over a, b, and c should be replaced with the following summations respectively:

$$\sum_{a} = \sum_{c \in \mathcal{R}} \sum_{\substack{q \in \mathcal{P}_i \\ q \neq p}} \sum_{\tau=t}^{t+T_{ipkt}^{EX}-1}$$

$$\sum_{b} = \sum_{\substack{j \in \mathcal{WB} \\ j \neq i}} \sum_{q \in \mathcal{P}_j} \sum_{\tau = t}^{t + T^{EX}_{ipkt} - 1}$$

$$\sum_{c} = \sum_{v \in \mathcal{F}} \sum_{z \in \mathcal{F}} \sum_{\tau = t}^{t + T^{EX}_{ipkt} - 1}$$

Note that T^{EX}_{ipkt} functions as a "big M"-formulation. We know from the summations that the left hand side of the constraints can never exceed this value if r_{ipkt} takes the value 0.

Recording location of resource

In order to model the movement of a resource from one location to another, the variable γ_{fkt} must take the value 1 for each resource in all time periods, which is handled by Constraints (6.6.5):

$$\sum_{f \in \mathcal{F}} \gamma_{fkt} = 1, \qquad \forall k \in \mathcal{R}, t \in \mathcal{T} \tag{6.6.5}$$

If a P&A operation is conducted, the vessel performing the operation must be present in the well's location. Constraints (6.6.6) ensure this:

$$\gamma_{fkt} - \sum_{i \in \mathcal{WB}_{fb}} \sum_{p \in \mathcal{P}_i} r_{ipkt} \geq 0, \qquad \forall f \in \mathcal{F}^W, b \in \mathcal{B}_f, k \in \mathcal{R}, t \in \mathcal{T} \tag{6.6.6}$$

Movement of vessel

In order to record the movement of a vessel, we set the γ_{fkt} variable to 1 when transport to field f begins. Then, Constraints (6.6.7) ensure that the travel start variable θ_{zfkt} takes its approprate value:

$$\begin{aligned} \gamma_{fkt} + \gamma_{zkt-1} - \theta_{zfkt} \leq 1, \\ \forall (f, z) \in \mathcal{F} \mid f \neq z, k \in \mathcal{R}, t \in \mathcal{T} \mid t - 1 \in \mathcal{T} \end{aligned} \tag{6.6.7}$$

If a vessel is moving, no other movement of this vessel can happen during the travel duration. Also, no P&A operations can be conducted in the same period. Constraints (6.6.8) ensure this:

$$\sum_{i \in \mathcal{WB}} \sum_{p \in \mathcal{P}_i} \sum_{\tau=t}^{t+T_{zfkt}^{TR}-1} r_{ipk\tau} + \sum_{(u,v) \in \mathcal{F}} \sum_{\tau=t+1}^{t+T_{zfkt}^{TR}-1} \theta_{uvk\tau} \leq T_{zfkt}^{TR}(1-\theta_{zfkt}),$$
$$\forall (f,z) \in \mathcal{F}, k \in \mathcal{R}, t \in \mathcal{T} \qquad (6.6.8)$$

Note that T_{zfkt}^{TR} functions as a "big M"-formulation. We know that if θ_{zfkt} takes the value 0, the highest value possible for the left hand side is T_{zfkt}^{TR}. The time summations for $\theta_{uvk\tau}$ is only applicable for travel times longer than one day. This was done to avoid that the same θ_{zfkt} appeared on the left and right hand side of the constraints (which would make the constraints infeasible), and to ensure that the summation is not performed from a value to a lower value.

Variable declaration

Constraints (6.6.9) - (6.6.11) declares the variables in the operational model:

$$r_{ipkt} \in \{0,1\}, \qquad \forall f \in \mathcal{F}^W, b \in \mathcal{B}_f, i \in \mathcal{WB}_{fb}, p \in \mathcal{P}_i,$$
$$k \in \mathcal{R}_{bp}, t \in \mathcal{T}, \qquad (6.6.9)$$
$$\gamma_{fkt} \in \{0,1\}, \qquad \forall f \in \mathcal{F}, k \in \mathcal{R}, t \in \mathcal{T}, \qquad (6.6.10)$$
$$0 \leq \theta_{fzkt} \leq 1, \qquad \forall (f,z) \in \mathcal{F} \mid f \neq z, k \in \mathcal{R}, t \in \mathcal{T} \qquad (6.6.11)$$

Note that we model the θ_{zfkt} variable as continuous in the domain $[0,1]$, as it naturally takes the value 1 or 0 due to constraints (6.6.7) and its positive contribution to the Objective Function (6.6.12).

6.6.5 The Objective Function

The Objective Function (6.6.12) is a minimisation function that minimises the costs of renting a vessel for P&A operations including movement of vessels between fields. The fixed mobilisation costs are also included. The last row is included in order to count the rental costs associated with the transport of a vessel back to the port, a cost which is not included in the first summation, as γ_{fkt} takes the value 1 when the movement of the vessel to the port begins, and that we have not included rental cost for the period in which γ_{fkt} is present in the port.

$$min \sum_{f \in \mathcal{F}^W} \sum_{k \in \mathcal{R}} \sum_{t \in \mathcal{T}} C_k^R \gamma_{fkt} + \sum_{(f,z) \in \mathcal{F}} \sum_{k \in \mathcal{R}} \sum_{t \in \mathcal{T}} C_k^{MOB} \theta_{zfkt} + \sum_{f \in \mathcal{F}^D} \sum_{z \in \mathcal{F}^W} \sum_{k \in \mathcal{R}} \sum_{t \in \mathcal{T}} C_k^R T_{zfkt}^{TR} \theta_{zfkt} \quad (6.6.12)$$

The operational model in its entirety consists of Constraints (6.6.1)-(6.6.11) and the objective value (6.6.12)

6.7 Possible Model for Well Production

During the course of writing this thesis, we investigated the possibility developing a model that made use of publicly available data and decline rate theory to forecast each wellbore's production. One possible interesting analysis would be to investigate whether an operator should TP&A some wells on a field or installation, and then come back to PP&A the remaining ones later. Also, one could aggregate the wellbores' production levels to obtain different installation's production levels, which could form a basis for investigating costs and optimal shut down time on an installation level rather than on a field level. The approach was discarded due to lack of data on production start times, historic production data on abandoned wells and the difficulties regarding inclusion of injection wells. It is presented here only to show a possible approach for forecasting well production if such information was obtainable.

Depletion rate[2] and decline curve analyses are widely used by analysts and researchers to estimate a well's or field's production (Höök, 2009). Simplified models are needed due to the inaccessibility of necessary data for people outside oil companies. Arps et al. (1945) proposed different mathematical curves to describe the production of a single well once the well has obtained the onset of decline. This onset of decline of production in a well usually starts immediately after production is commenced (Hyne, 2012). It should be mentioned that one curve may not be enough to obtain a good fit, and it might be necessary to combine different curves.

[2] The drop in reservoir pressure or hydrocarbon reserves resulting from production of reservoir fluids

The simplest decline curves used in literature today are characterised by only three parameters. Let r_0 be the initial production, δ the decline rate, and β the shape parameter. The exponential, harmonic and hyperbolic decline curves (well production curves) for a single well or field (when decline phase is reached) are presented in equations (6.7.1), (6.7.2), and (6.7.3), respectively:

$$q(t) = r_0 e^{(-\lambda(t-t_0))} \tag{6.7.1}$$

$$q(t) = r_0 \left[e^{(-\lambda(t-t_0))}\right]^{-1} \tag{6.7.2}$$

$$q(t) = r_0 \left[1 + \lambda\beta(t - t_0)\right]^{-1/\beta} \tag{6.7.3}$$

Where $q(t)$ is production at time t, and t_0 is the start time of production. We made an attempt to utilise Equation (6.7.1) to model the historic and forecast production of each well based on historic and forecast production levels of the fields in which the wells operated. The approach of fitting modelled data to historic data is inspired by the history matching approach used by several oil companies to simulate reservoir behaviour. By using real production data and forecast data from UCube, the goal was to estimate what the production must have been, and must be in the future, for the wells that are located in the field, by minimising the squared difference between the sum of modelled data and real and forecast data. We were able to obtain a good fit for some fields and poor fit for other. For instance, we obtained a good fit for the Alve field. In figures 6.1 and 6.2, the resulting forecast of the wells of which Alve comprise that have status Online/Operational is presented. In Figure 6.3, the comparison between our model and historic and forecast data from UCube on the field level is given.

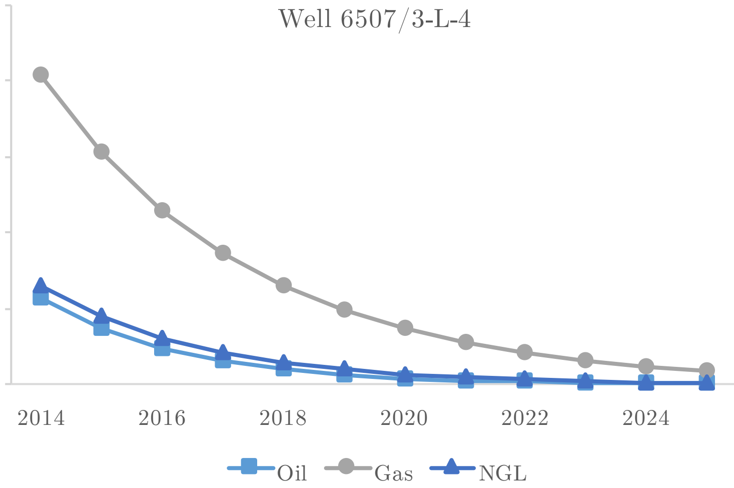

Figure 6.1: Forecast production of well 6507/3-L-2

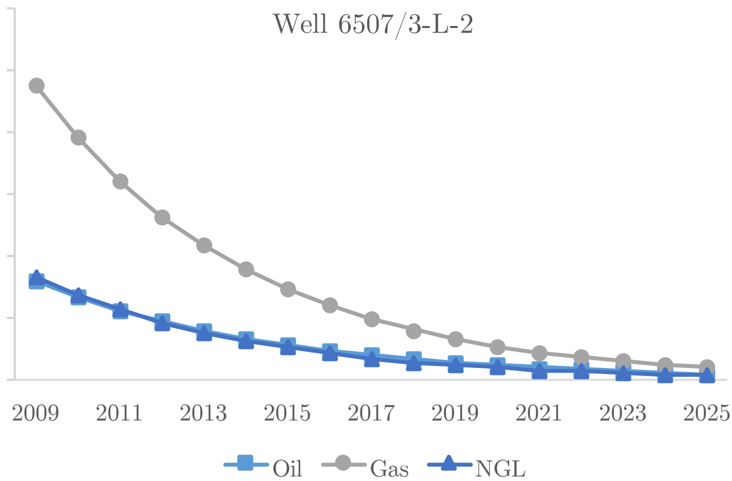

Figure 6.2: Forecast production of well 6507/3-L-4

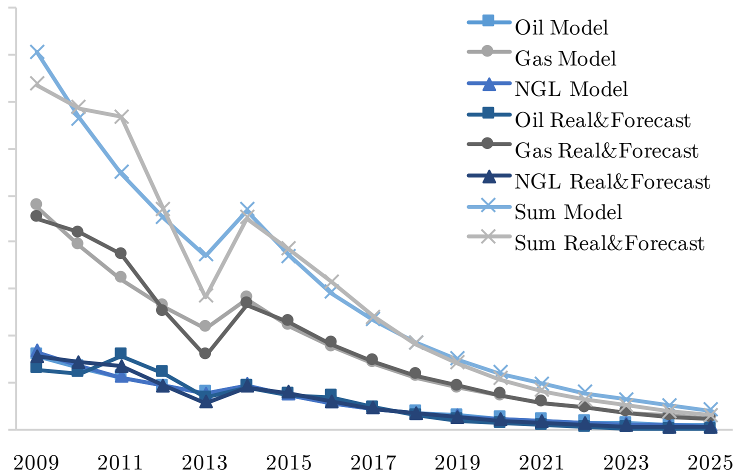

Figure 6.3: Model fit for Alve

Although we obtained fairly good fits for some fields, the results were deemed as not realistic enough. The reasons for why we believe this, and why we obtained poor fits for some fields include:

- Injection wells were not included. These would contribute to increasing the pressure inside the reservoir, and keep production at a level that is not captured by any of the decline curves
- Information on when development wells were completed is obtainable, but not when they started to produce. This could lead to deviations.
- Forecast data is yearly, and real production data were chosen to be yearly as well. This makes it even more difficult to estimate the real start-up times of development wells.
- Combination of decline curves were not considered
- It is difficult to calculate how much a wellbore that has been plugged has produced in the past.

Using these decline curves to estimate a well's or a field's future production before production start might be an appropriate approach. However, when estimating each well's contribution to a field that has been producing, this approach did not provide results that would be realistic enough to be used in an optimisation model for calculating optimal P&A and shut down time. This approach was therefore discarded, but it shows what one can be able to obtain from a limited information. If injection wells and monthly production were included, and by using a more sophisticated optimisation approach and using a combination of decline curves, it is reasonable to assume that the model would fit the real and forecast data in a better way, and provide valuable estimates on a well's future production which could be used in cost estimation and analyses of shut down times on an installation and well level rather than on a field level.

Chapter 7

Results Strategic Level

In this chapter, results from the running the strategic model for different cases is presented in sections 7.1, 7.2, 7.3 and 7.4. Results from the real options model is then given in Section 7.5, where we compare this approach with the deterministic approach in the strategic model. We summarise our findings from the strategic model in Section 7.6. In order to keep track of optimisation model runs considered, we list the different runs in Table 7.1, and refer to these names when we present and discuss the results.

Table 7.1: Different runs of the strategic model

Run Name	**Constraints/objective function**	**Comments**
SBC1	(6.1.6)/(6.1.15)	Without shut down.
SBC2	(6.1.1)-(6.1.14)/(6.1.16)	No temporary shut down. Shut down one year after production stop.
SBC3	(6.1.1)-(6.1.14)/(6.1.16)	Full model.
SBC4	(6.1.1)-(6.1.14), (7.4.1)/(6.1.16)	Same as SBC3. Connecting fields constraints added.

7.1 Shut Down Without P&A Costs - SBC1

First, we want to look at the optimal production stop time of the fields disregarding the costs related to any P&A activities, i.e. only regarding the income and OPEX from production of each fields. The reason why we include this result is to obtain a basis for which we can compare the results from SBC2 and SBC3. Some industry actors claim that P&A costs should not be included in the shut down decision, as this is a cost that is incurred independently on production profits.

In order to justify the assumption that all OPEX are independent on production levels, we did the following: We first assumed that 50% of OPEX is independent on the chosen production level. Then we ran the model assuming that all OPEX were directly related to the production. This was done by letting production be less than or equal to forecast production, and changing the contribution of the OPEX to the objective function from $C^O_{ft}u_{ft}$ to

$$a \times C^O_{ft}\frac{p_{fst}}{P_{fst}} - (1-a) \times C^O_{ft}u_{ft}$$

where a was the fraction of the OPEX related directly to the proportion of the chosen production level.

When investigating the production levels when running the model with these modifications, we observed that the production was lower than the production profile in many periods, and sometimes zero. This happened because the model chose to not produce in periods where OPEX are higher than the income from production. This is not realistic, as an operator does not decide easily to stop production whenever costs are high.

For the remainder of this chapter, we treat OPEX as fixed, as we assumed in the original model. As we are dealing with deterministic data, we believe that this is the most correct way of representing the future cash flows based on the available information. The results from running the model without P&A costs and with OPEX as fixed is shown in its entirety in Appendix F, Table F1. Table 7.2 shows an excerpt from this result.

Table 7.2: Excerpt of results from SBC1

Field	Model	Forecast	Field	Model	Forecast
Alvheim	2034	2035	Brage	2025	2027
Skirne	2020	2021	Sigyn	2036	2037
Gudrun	2030	2032	Urd	2032	2033
Gullfaks Sør	2051	2065	Trym	2025	2028
Mikkel	2071	2081	Visund Sør	2033	2038
Njord	2030	2042	Norne	2021	2022
Ormen Lange	2035	2042	Åsgard	2031	2034

The reason why we observe differences between our model and Rystad Energy's forecast is probably because Rystad Energy base their production stop time on expected extraction of hydrocarbons based on recoverable resources, and does not take into consideration when the field is producing economically. These results forms the basis for the discussion on differences found in optimal stop time when we included P&A costs, which is the topic for the next section.

7.2 Shut Down Time With P&A Costs - SBC2

In the SBC2 run, we include shut down costs and assume that shut down must happen the year after production stop. Temporary shut down is not allowed in this run. The reason why we do this is to obtain a result which can be compared with SBC1, and with the real options model presented later in this chapter. The results are given in Appendix G, Table G1. An excerpt of the results is given in Table 7.3.

Table 7.3: Excerpt from results from SBC2

Field	Production stop SBC1	Production stop SBC2	Difference	Shut down SBC2
Gudrun	2030	2030	0	2031
Gyda	2016	2019	3	2020
Tambar Øst	2020	2021	1	2022
Troll	2099	2089	-10	2090
Tune	2018	2020	2	2021
Valemon	2029	2030	1	2031
Åsgard	2031	2034	3	2035

In Section 7.2.1, we discuss the differences between findings in SBC1 and SBC2, and in Section 7.2.2, we provide the breakdown of the aggregated profit calculation, together with a comparison with the cost estimate presented in Chapter 5, Section 5.2.

7.2.1 Discussion on SBC1 and SBC2 Differences

We will now discuss the main findings from this result, and explain in detail why we observe different shut down times.

Differences in Production Stop Times

For the non-producing fields (Tor, Gaupe, Heimdal, Hod, Huldra, Yme), the difference is zero because we have imposed that these fields must be shut down in 2016. For the other cases where the difference is 0, there are two possibilities why this result occurs: One is that production is continued until the production profile reaches zero for both cases. Another possibility is that the savings from postponing shut down is not enough to outweigh the loss of continuing producing. This happens for fields where the OPEX are high compared with the shut down cost. For instance, the Edvard Grieg's forecast production ends in 2033, while running SBC1 and SBC2 results in the optimal stopping year of 2031. In 2032, the discounted OPEX is about twice as high as the P&A costs, and the income from producing in 2033 is not considerable. Postponing shut down would not result in discount rate savings that are larger than the discounted negative profits. The same is true for other fields that are categorised as producing fields and where the optimal stop time is the same for SBC1 and SBC2.

For fields where the difference is positive, postponing the production stop time in order to postpone shut down is cheaper than stopping production at the time where costs from production exceeds income from production. The reason for this behaviour is due to the discount on postponing shut down results in total alternative costs of capital for the relevant years higher than the total loss when producing in the same years. This is due to the fact that the shut down costs are much higher than the other cash flows. This happens for 43 of the 82 fields. However, we obtain some results that is probably not realistic:

For Oseberg and Njord, the differences are 40 and 12 years respectively. The estimated total P&A cost in Oseberg is 1 658 MUSD, meaning that there are huge potential savings from postponing shut down savings due to the discount rate, which might be one reason why we observe this result. Another and probably more realistic reason is due to the input data on OPEX. in Oseberg, the

OPEX suddenly drops in 2053 by 98%. The reason why this happens is that when we calibrated our data with NPD, we needed to include production levels from Oseberg Delta S2, a field only present in the UCube database. The merging of the two fields was performed because historical values for the two fields was equal to the historical figures for Oseberg in NPD. UCube does not forecast any OPEX in Oseberg after 2052 (but production levels are positive until 2100). However, for Oseberg Delta S2, OPEX is forecast until 2099, but this OPEX is much lower than for Oseberg. Our model then, calculates income from both of these fields/installations but only OPEX from Oseberg Delta S2 from 2052 onwards. Then, the benefit from discounting the shut down costs is therefore much higher than the OPEX incurred in these 40 years, which leads to this (probably) unrealistic result. This is an example of the challenge one faces when collecting data from different sources. We should therefore tread carefully when analysing and interpreting results from such fields where data may be inconsistent. This situation applies to very few fields. Thus, the large proportion of the results will not exhibit this behaviour.

The reasons why some stop times are lower when running the model with P&A costs can be many. When we include the P&A costs, the optimal production stop time is ten years earlier for Troll and Valhall. The reason for this is that the discount rate drops in the years between 2090 and 2089, leaving the option of shutting down in 2090 as the better alternative than shutting down between 2090 and 2100. The discount rate also drops between 2055 and 2056, which is the reason why the optimal production stop time for the Heidrun field is earlier when considering shut down costs. The economic gain of shutting down in 2055 due to the discount rate is therefore higher than the alternative to produce between 2055 and 2059. If we were operating with a flat discount rate, we would expect these shut down times to be later than the ones obtained from SBC2.

However, despite inconsistency in data and time inconsistency due to varying discount rate, the main finding is that the production stop time on average is postponed compared to the findings from SBC1 due to the discount rate effects on the shut down costs.

More on the Effect of Discount Rates

The discount rates used in the SBC1 and SBC2 are 4% for cash flows incurring between 2016 and 2055, 3% between 2056 and 2090, and 2% from 2091 onwards. Six of the optimal shut down times found were in 2055 and three in 2090. The reason why these shut down times are chosen by the model is either that the production forecast is zero, or that the drop in discount rate makes shutting down the better alternative than to postpone P&A even further.

In reality, planning of P&A operations far into the future is not common. When operating with discount rates that drops at a certain point in time, we assume that the decision to shut down must be done today in order for the decision maker to exploit the different interest rates obtainable in the market in the current year. However, due to uncertainty regarding recoverable resources, depletion rate, petroleum prices and other factors, the decision on whether to shut down a field in decades to come is not taken decades in advance, but rather at a point in time where the decision maker has more knowledge about these factors and production has dropped to a level where the actual decision on whether to continue to produce or planning for shut down should be made. Then, the decision maker would probably face another discount rate and the optimal shut down time would probably change.

Although the time dependent discount rate might result in some unrealistic results, we believe the focus should be on the results found for the fields in the next couple of decades, as both production and OPEX forecasts are more realistic for this period. However, when we present results for the entire period 2016-2100, we will continue to use this time dependent discount rate.

7.2.2 Numerical Results for SBC2

When presenting the numerical results from the SBC2, we also compare the results we obtain when we run the SBC2 with the production stop times found in SBC1. This analysis is interesting since, as mentioned, some industry actors claim that shut down costs should not be considered when planning the optimal time for shut downs. We have already seen that there are differences in optimal shut down times when we include and exclude P&A costs. Here, we present the monetary differences if we impose stopping times from SBC1 when running SBC2 (denoted SBC2(1)). Table 7.4 shows these results.

Table 7.4: Numerical results from SBC2 and comparison with imposed stopping times from SBC1 [MUSD]

Run	**Income**	**OPEX**	**Shut down cost**	**Total profits**
SBC2	621 690	-150 971	-17 122	453 597
SBC2(1)	619 665	-148 547	-19 161	451 957
Difference	2 025	2 589	- 2 039	1 475

Total income increases with 2 025 MUSD when taking into account P&A costs.

This is expected, as the production stop time is postponed and in these years, the fields would gain income from producing. OPEX increases by more, 2 589 MUSD. This means that if we look at income and OPEX isolated, the postponed production stop leads to a total loss of 564 MUSD. But when we include the benefits from postponing shut downs, we observe that this more than outweigh the loss associated with production (we gain 2 039 MUSD by postponing shut downs). Based on our dataset, we can conclude that when planning P&A operations, operators should take into account the potential savings from postponing shut down even though they will produce with a net loss in the postponement period if we look at income and OPEX isolated. For the total NCS, the inclusion of P&A costs in deciding when to shut down results in total profits of 1 475 MUSD.

When running the SBC2, we know that a large proportion of the costs related to shut down will incur in the future. In Chapter 5, we obtained a cost of 47 722 MUSD for the ML ML case (which is the case used in the SBC2). This was based on the assumption that all wellbores were to be P&A'ed now. When we compare this result with the NPV of the shut down costs in Table 7.4, we see that the total P&A cost decreases by over 30 000 MUSD. We are neither taking into account that prices related to vessel rental may change (due to e.g. higher or lower demand and technology development), nor that technology development might enable faster P&A operations in the future in this calculation. It should be interpreted as a coarse estimate of difference between the NPV of P&A cost incurring in the future and the P&A costs if all operations were to be executed now. However, this result shows that the true costs might not be as high as we include the time value of cash flows. Figure 7.1 shows the cost of shut down from SBC2 distributed in decades, together with the number of wellbores that corresponds to the fields whose optimal shut down year is in the same decade.

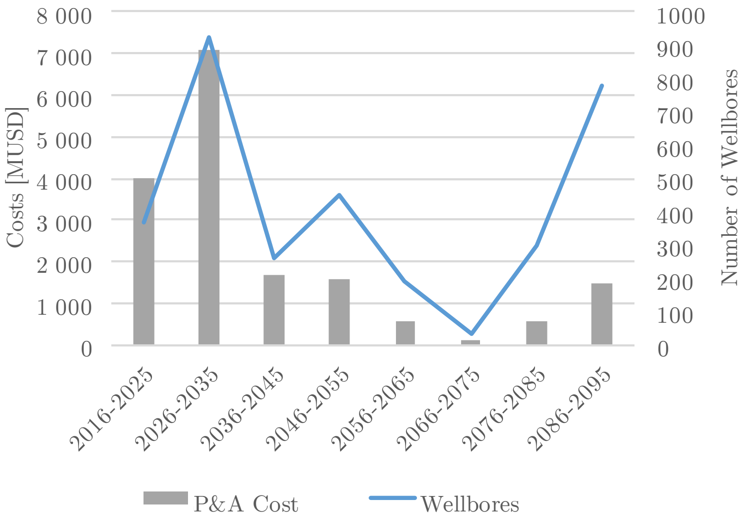

Figure 7.1: Distribution of P&A costs in decades where they incur, together with the associated number of wellbores in the same period.

Figure 7.1 tells us that the largest proportion of the P&A costs incurs in the first two decades. Approximately 39% of all current development wellbores must be P&A'ed in these periods. This high cost is expected as these costs have not been discounted as much as the costs that incur in the future.

As we move rightwards in the graph, we observe that in the last two decades, the number of wellbores to be P&A'ed are fairly high, but the associated costs are very low in comparison. Here we see the effect of the NPV clearly. If we compare the first and the last decade, we see that the costs incurred in the last decade is only 37% of the costs incurred in the first decade, but the number of wellbores that need P&A is over twice as many. We need to be cautious with these numbers, because it is not only the number of wellbores that determine the P&A costs, but rather what kind of operations these wellbores need.

If we investigate the two decades 2036-2045 and 2046-2055, one could conclude that the reason why the difference between number of wellbores are so big, while the difference in costs are not, is due to the proportion of wellbores in the latter period that need phase 3 operations are bigger (these are the cheapest operations). However, this is not the case. Approximately 1/3 of the operations in both decades are phase 3 operations. This means that the main determinant of the cost difference in this case must be the discount rate effects of the shut down costs.

7.3 Temporary Shut Down and Reopening - SBC3

In the SBC3, we ran the entire model with the option to temporarily shut down and reopen the field. We assumed a temporary shut down cost and reopening cost of 5% of total shut down costs, and 10 MUSD as monitoring cost. These costs are fictitious numbers that is used only to show how the model behave. The results are shown in Appendix H, Table H1, and an excerpt from this table is shown in Table 7.5.

Table 7.5: Excerpt from results from SBC3

Field	**Prod. stop**	**Temp. shut down**	**Monitor start**	**Monitor end**	**Perm. shut down**
Sleipner	2022	2023	2024	2026	2027
Snorre	2041	2042	2043	2045	2046
Snøhvit	2044				2045
Statfjord	2025	2026	2027	2029	2030
Statfjord Nord	2053	2054			2055
Statfjord Øst	2026	2027			2028
Svalin	2028				2029

With our input on the cost of temporary shut down, reopening of production, and monitoring, no fields chose to temporary shut down the field and reopen production. The reason for this is that avoidance of OPEX in any period were lower than the cost related to temporary shut down, monitoring and reopening.

In Table 7.5 we see that some fields chooses to shut down immediately after production stop (e.g. Snøhvit and Svalin). Others choose to temporarily shut down, and permanently shut down the year after without monitoring (e.g. Statfjord Nord and Statfjord Øst). This is because the modelled cost of temporarily shutting down in one year is lower than the gains from postponing the high permanent shut down cost and avoiding net profits in this period. In this case, temporary shut down is in effect permanent shut down. This is also true for fields that chooses to temporary shut down a field and monitor the field during the time period restricted by the time limit (set to three years) only to exploit the effect of the discounted costs of permanent shut down.

We ran the model without reopening costs, and found that three fields chose to temporary shut down in order to rather bear the cost of monitoring than OPEX (and possibly low profits) in some periods. The results from SBC3 is not directly applicable to the situation on the NCS. To our best knowledge, operators do not shut down entire fields temporarily in order to avoid OPEX, low profits or exploit the economic benefit of postponing shut down cost. Rather, such decisions are made in anticipation of further redevelopment of the field which could lead to positive cash flows in the future, or that a field must stop producing because it is connected to another field that is being shut down.

7.4 Connecting Fields Together - SBC4

Some fields are connected to each other through multi-field wellbores and/or production facilities. This consideration has not been taken into account so far. We will now look at an example of how we can include this in the strategic model.

According to NPD, Jotun was expected to produce until 2021, but due to low production from the connected field Jette, Jotun is expected to shut down during 2016. In the SBC2, we found that optimal stopping time for Jotun was 2016 and 2017 for Jette. This result is due to forecast production info from UCube, where forecasted production is positive until 2016 for Jotun and 2017 for Jette (this means that their forecast is not necessarily similar to what operators report to NPD). In this section, we will look at examples of similar situations on the NCS, and require that if one field from a set of two or more connecting fields must shut down, the other fields must either stop production temporarily and reopen production until the field that must be shut down has completed its shut down operations, or that these must stop production permanently. Due to restricted information, we have only included Jette and Jotun as real connecting fields, and have assumed connection between some other fields, based on interpretations of information from NPD. The results from running the model with these assumed connections should be interpreted as an example of what kind of answers the model can provide if real information were obtainable.

Table 7.6 lists the fields that will be used in the analysis. In reality, it is believed that one field "dominates" the other, i.e. if one field must shut down, this influences the other, but not the other way around. This assumption is based on the fact that some or all wells in a field can be connected to a production facility on another field. However, since most of the assumed dominant fields' optimal shut down time according to SBC2 is later than the dominated fields' optimal shut down time, we assume that they will influence each other equally in order to show how the model behave.

Table 7.6: Connected fields on the NCS

Connected Fields					
Jette	&	Jotun	Sleipner	&	Gungne
Brage	&	Oseberg Øst	Sygna	&	Statfjord Nord

If one of the fields starts temporary or permanent shut down, the other must cease production. Constraints (7.4.1) were included:

$$x_{ft} + y_{ft} - u_{zt} \leq 0, \qquad f \in \mathcal{F}', z \in \mathcal{F}'_f, t \in \mathcal{T} \tag{7.4.1}$$

Where $\mathcal{F}'$ is the set of fields with dependent fields, and $\mathcal{F}'_f$ is the set of fields on which field f is dependent. The numerical results are presented in Table 7.7 together with a comparison with numerical results obtained from running SBC3. The numbers for temporary shut down are aggregated costs of temporary shut down and monitoring.

Table 7.7: Comparison between results from SBC3 and SBC4.
PSD=Permanent shut down cost, TSD=Temporary shut down cost. [MUSD]

Run	**Income**	**PSD**	**OPEX**	**TSD**	**Total Profits**
SBC4	620 206	16 175	149 886	655	453 490
SBC3	621 115	16 007	150 300	667	454 140
Difference	**-909**	**168**	**-414**	**-12**	**-650**

We see that only when imposing a few dependencies, the total profits decreases with 650 MUSD. For future research, we recommend a thorough analysis on such dependencies where one should include the fact that some fields dominate the other. The reason why we recommend this approach is that it potentially has a great impact on the income and costs of operators including costs related to shut down and potentially the decision on when to shut down.

7.5 Results Real Options Model

In this section, results from running the real options model for Brynhild, Svalin and Vigdis are presented, along with discussion of the results and comparison with the deterministic approach in the SMB2.

7.5.1 Brynhild

In Figure 7.2, the production forecast for the Brynhild field for the period 2016-2025 is illustrated together with the OPEX (adjusted for inflation, not for discount rate).

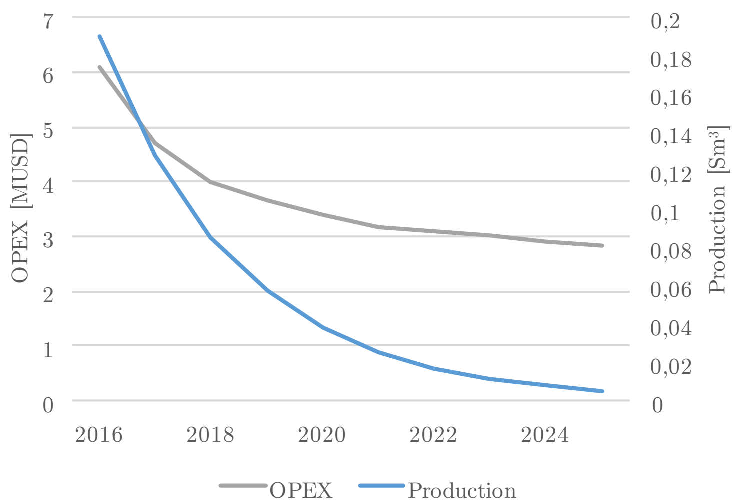

Figure 7.2: OPEX and production profile for Brynhild field. OPEX values on left axis and production on right axis (Rystad Energy, 2016).

The parameters for the conditional expectation function for each time period are given in Appendix I, Table I1. In Table 7.8, the average discounted exercise and continuation values for Brynhild for each period are presented.

Table 7.8: Results from the real options model for Brynhild. All values are average and discounted to today's value [MUSD].

Year	**Exercise value**	**Continuation value**
2025	-70.85	-69.80
2024	-73.35	-33.14
2023	-76.76	0.01
2022	-81.59	2.16
2021	-80.98	5.56
2020	-99.09	10.92
2019	-114.71	19.22
2018	-138.34	32.14
2017	-174.21	52.10
2016	-228.36	82.31

The optimal expected shut down time is when there are no forecast production, i.e. in 2026. We see that the continuation value is always lower than the exercise value, meaning that it is not optimal to shut down the field until we reach the period of no production. In order to compare the real options model with the SBC2, we changed the input data on oil price development in the strategic model to the average of the price paths generated by the Monte Carlo simulation for the relevant period. The deterministic approach gave the same result. Since both models suggests exercising in the last possible period, we do not clearly see the effects of the real options model in this case.

The reason why the SBC2 finds the same solution is that shut down cost are very high compared with the loss of producing in non-profitable periods. Continuing producing in 2016-2025 is therefore the better alternative since the effect of the discount rate is higher than the profit loss. In 2023-2025, the average continuation value discounted is negative. This is due to the inclusion of the shut down cost in 2026 when calculating the continuation value in previous periods. We observed the same when running the real options model for Svalin and Vigdis as well. One should therefore not interpret negative continuation value as a trigger for shut down.

7.5.2 Svalin

Figure 7.3 shows the production profile for Svalin in the years 2016-2028 and the OPEX (adjusted for inflation, not discount rate) that is used in the real options model. In Appendix I, Table I2 the calculated regression parameters for each year used to find the conditional expectation function are given, and in Table 7.9 the average exercise and continuation values for each year discounted are presented.

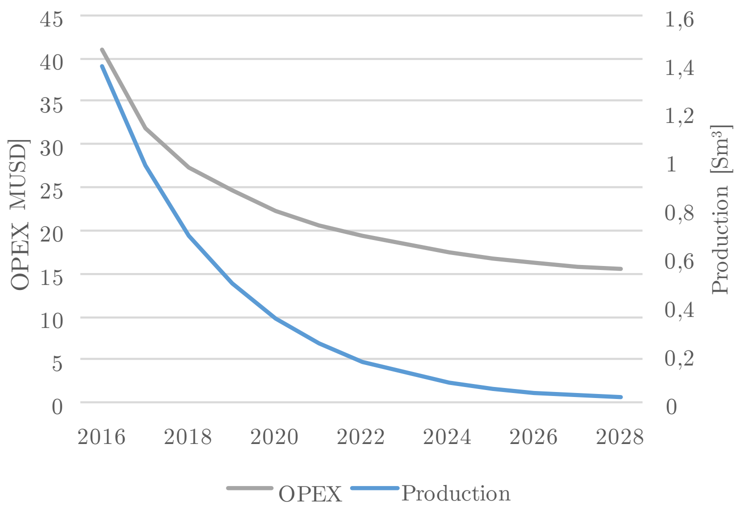

Figure 7.3: OPEX and production profile for Svalin field. OPEX values on left axis and production on right axis (Rystad Energy, 2016).

Table 7.9: Results from the real options model for Svalin. All values are average and discounted to today's value [MUSD].

Year	**Exercise value**	**Continuation value**
2028	-48.07	-56.91
2027	-46.18	-43.72
2026	-46.61	-27.15
2025	-50.50	-12.04
2024	-59.56	2.92
2023	-76.65	19.43
2022	-105.63	40.89
2021	-152.61	71.21
2020	-226.03	115.44
2019	-338.33	180.31
2018	-507.89	275.97
2017	-761.16	416.62
2016	-1133.15	618.80

These average exercise and continuation values suggest that the expected optimal shut down time is in 2028. In order to compare this result with the deterministic approach, we used the same approach as for the Brynhild case. The result from SBC2 suggested that the optimal shut down time was 2027. We here observe a value of waiting with the irreversible decision of shutting down the field. This value of waiting is due to the uncertainty of the actual cash flows that will incur in the future. Since the price development might lead to profit gain, or profit loss that is less than the value of postponing shut down, the value of keeping the option alive in 2027 is higher than the value of exercising.

7.5.3 Vigdis

Figure 7.4 shows the production profile for Vigdis in the years 2016-2033 and the OPEX (adjusted for inflation, not adjusted for discount rate) that is used in the real options model.

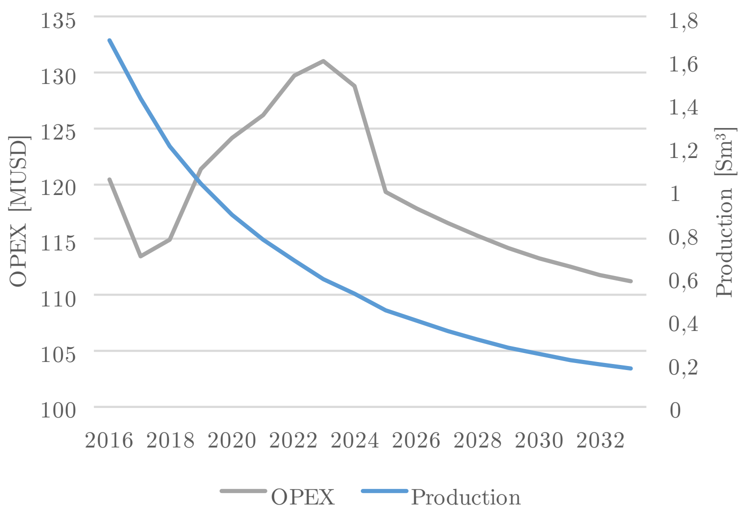

Figure 7.4: OPEX and production profile for Vigdis field. OPEX values on left axis and production on right axis (Rystad Energy, 2016).

Figure 7.4 shows a different shape of the forecast OPEX than Figure 7.2 and Figure 7.3 show for Brynhild and Svalin. This time, OPEX is not steadily decreasing at a given rate, but decreases the first year, and increases from 2017 to 2023 before it decreases again. It is difficult to provide a good answer to why the forecast OPEX follows this shape. One reason might be that the UCube database base their forecast for Vigdis on information that is not accessible for outsiders, such as investment plans developed by operators. It should be mentioned that the Vigdis field actually comprise two fields in UCube: Vigdis and Vigdis Nordøst. These were merged to mach the historic data in UCube with the historic data from NPD. The OPEX data for these two fields are different, but does not influence the upward development in the OPEX between 2017 and 2023. The sudden reduction between 2024 and 2025 however, is due to no information about OPEX for Vigdis Nordøst.

In Appendix I, Table I3, the regression parameters used in the conditional expectation function for each period for Vigdis are given. In Table 7.10, we present the average exercise and continuation values discounted obtained for each time period.

Table 7.10: Results from the real options model for Vigdis. All values are average and discounted to today's value [MUSD].

Year	**Exercise value**	**Continuation value**
2033	-336.52	-383.01
2032	-322.71	-300.93
2031	-311.95	-217.27
2030	-304.68	-154.74
2029	-302.30	-105.78
2028	-306.18	-68.39
2027	-317.06	-37.37
2026	-337.10	-6.36
2025	-367.30	27.15
2024	-407.95	60.12
2023	-464.03	99.12
2022	-544.44	146.87
2021	-655.05	202.20
2020	-801.07	261.86
2019	-994.05	331,69
2018	-1246.25	421.56
2017	-1571.24	536.16
2016	-1979.92	681.14

The expected time at which the option of exercising is optimal is in 2033. In order to compare this results with the SBC2, we used the same approach as for the other fields. We found that in this case, the optimal shut down time using the deterministic model was 2029. Again, we observe that the results from using our real options approach suggest that postponing P&A even more than the deterministic model suggests. The difference of four years is considerable.

One of the reasons why we observe so large differences when comparing SBC2 with the real options model in this case, compared to when comparing the results for Brynhild and Svalin, might be due to the high forecast production level in Vigdis. When production is relatively high in the tail region of the production profile, the impact of variable oil prices will be bigger than if forecast production is low in this region, as was the case for Brynhild and Svalin.

7.5.4 Possible Sources of Error

Although we were able to obtain interesting results from our real options approach, some points regarding this approach should be discussed.

We chose profits as the independent variable and the expected cash flow in the next period as dependent variable, and assumed a second order polynomial conditional expectation function. The cash flow from the next period was either the profits obtained in that period or the exercise value, dependent on which of these were highest. It might be difficult to argue that one period's profits should be explanatory for the next years exercise value as these are not directly related. When using this approach on a call or put option of a stock, this relation is more evident. This might have lead to conditional expectation functions that did not represent a realistic continuation values of the option. Further, choosing a different type of regression function could have provided other, and maybe more realistic results. These considerations however are beyond the scope of this thesis, but it is worth to mention that one should be careful when choosing independent and dependent variables for the regression, as well as regression functions.

In their example with an American put option on a stock, Longstaff and Schwartz (2001) only regress over the stock prices in a period in which the option is in-the-money. This is done to make the model work more efficiently, and to obtain a better conditional expectation function. We did not use this approach, but rather regressed over all paths, as we could not assess whether the exercise option was in the money or not in a convenient and realistic way.

By simulating price paths for each year, we assume that the prevailing price in one year will stay constant throughout the year. If we were to simulate the price paths in intervals of weeks or days, we believe that we could obtain a better representation of the uncertainty in the oil price. That being said, all other input data were given in years, and the assumption that a shut down decision is made only one time each year is deemed as realistic. Therefore, we believe that the approach of simulating prices for each year was sufficient for our purposes.

Despite these potential sources of error, we believe that the real options model provided valuable insights on how uncertainty in one variable can affect the expected optimal shut down time.

7.6 Conclusion Strategic Level

Our findings from running the strategic model and real options model can be summarised as follows:

- A large proportion of the wellbores that require P&A are connected to fields whose optimal P&A time is far into the future. However, the largest proportion of the costs incurs in the first two decades from now.
- Operators should include costs of P&A when determining when to shut down a field. Our results showed that the P&A costs could reduce by a order of magnitude of thousands MUSD.
- For 36 fields, the optimal production stop time is the same when running the model with and without P&A costs.
- For 3 fields, the optimal production stop time when running SBC2 is earlier than the optimal stop time when running the model without shut down costs (SBC1), mainly due to time inconsistency from considering a time dependent discount rate.
- For 43 fields (52%), the optimal production stop time is later when running SBC2 compared with SBC1, due to the gains from postponing shut down costs.
- In general, the high permanent shut down costs give incentives for postponing P&A, even though this means producing with losses or bearing monitoring costs in periods.
- Expected optimal shut down time in the real options approach deviated from the optimal shut down time obtained by the deterministic approach in SBC2 for two of the fields. The value of waiting to observe oil prices in the future suggest further postponement of the shut down decisions.
- For fields where the production levels are very small in the tale region, such as Brynhild and Svalin, the effect of treating the oil price as stochastic is minimal due to low effects on the profits.

- For fields where the production levels are high in the tale region, such as Vigdis, the effect of treating oil price as stochastic becomes more apparent.

Chapter 8

Results Tactical Level

In this Chapter, we present the results from running the tactical model. We ran the model several times with different constraints and time horizon. The different runs are described in Table 8.1.

Table 8.1: Different runs of the tactical model

Run Name	**Constraints/objective function**	**Time horizon**
TBC1	(6.3.1)-(6.3.19)/(6.3.20)	Two years.
TBC1IM	(6.3.1)-(6.3.9), (6.3.11)-(6.3.19), (8.1.1)-(8.1.3)/(6.3.20)	Two years.
TBC2	(6.3.1)-(6.3.9), (6.3.11)-(6.3.19), (8.1.1)-(8.1.3)/(6.3.20)	Three years.

In TBC1, we are assuming a cost associated with deviating from the optimal shut down time found in SBC2 to 0.1 MUSD for each period of postponing and 0.2 MUSD for each period of expediting. This is later changed for TBC1IM and TBC2 to 10 MUSD and 20 MUSD for postponing and expediting, respectively. Further, we are assuming a fixed mobilisation cost of 1 MUSD for RLWI and LCV and 1.5 MUSD for MODU, independent on travel cost. In the TBC1, we assume equal travel time between all locations, which is a simplification that we changed in the improved model. The WOW factor is chosen to be 1.8 (80% increase) in

January and December, with a near linear decrease to 1 (0%) in June and July from both sides of the year. We use travel times given in Appendix J. All these assumptions are valid also for the operational model except for the change cost and that we adjust the travel times. We further assume a month consist of 30 days.

As we were not able to obtain estimates on these costs we have used fictitious numbers which are subject to discussion, but are chosen only to show how the model can be used. However, probably the most important figures, such as rental rates and durations of P&A operations are the same as we used in the cost estimate. The results shown in this chapter should not be interpreted as a suggestion for an actual schedule, but rather as an approach to obtain valuable insights on how the tactical model might be used.

In Section 8.1, we show the computational results from running the TBC1, and discuss possible improvements of the model. In Section 8.2, we provide the optimal schedule for a two year horizon. Then, we increase the time horizon to three years in Section 8.3. Note that even though we are only considering subsea wellbores, some of these might not carry the letter H in the name. The reason for this is that it is the initial well, from which sidetracks that carry the letter H are drilled. From now on, we split phase 2 of the P&A operations in two, as described in Chapter 2, Section 2.2.

8.1 Statistical Results TBC1 and Improvement of Model

In Table 8.2, key statistics obtained after running the TBC1 is given.

Table 8.2: Computational results from TBC1. Objective function value in [MUSD]

Statistics		TBC1
Constraints	Originally	6 653
	Presolved	4 019
Variables	Originally	4 587
	Presolved	3 209
Global entities	Originally	3 561
	Presolved	3 101
Run-time		47 575.3s
Objective value		143.4
Optimality gap		4.55%

We chose to stop the execution of TBC1 after 47 575.3 seconds. Our goal with the tactical MIP model was to create a resource allocation schedule for three to five years, and we suspected that the model needed to be improved in order to handle the increased number of global entities. Therefore, we did not deem it necessary to run the model longer to guarantee optimality. In the next sections, we will look at some improvements of the tactical model that resulted in shorter run-time but a slight loss of flexibility.

In the original formulation, we imposed binary restriction on the variables θ_{zfkt}. We can relax the binary restriction on this variable if we remove Constraints (6.3.10) and add Constraints (8.1.1)-(8.1.2):

$$\gamma_{fkt} + \gamma_{zkt-1} - \theta_{zfkt} \leq 1,$$
$$\forall f \in \mathcal{F}^W, z \in \mathcal{F} \mid f \neq z, k \in \mathcal{R}, t \in \mathcal{T} \mid t-1 \in \mathcal{T} \tag{8.1.1}$$

$$\gamma_{fkt} + \gamma_{zkt-1} - \theta_{zfkt-1} \leq 1,$$
$$\forall f \in \mathcal{F}^D, z \in \mathcal{F}^W, k \in \mathcal{R}, t \in \mathcal{T} \mid t-1 \in \mathcal{T} \tag{8.1.2}$$

θ_{zfkt} will take the value 1 only if a move is recorded between two fields. We know that it will take the value 0 otherwise, as the variable contributes positively to the objective function value. The reason why we split the constraints in two is because we want to reduce the idle time incurred when a vessel is moved back to the port. With these constraints, we lose some flexibility as the model no longer can choose which of the time periods the movement is performed, we may also obtain results that leads to unnecessary high idle time in some periods. However, we deemed it necessary to reduce the problem in order for the model to be solvable for the desired time horizon.

When adding these constraints, we also know that no movement nor P&A work can be conducted in the first period. Therefore, we removed all variables in time period t except for the γ_{fkt} variable. This means that all other variables for January 2016 will not be created, and thus January 2016 was removed as an alternative for P&A work. We could have included an extra entry in the set $\mathcal{T}$ that represented the period before January 2016, but this is not critical for the model with our data set.

We also removed the possibility for a vessel which is not appropriate for the P&A work on a specific field to be present at, or be transported to or from, this field. In our case, the only field in which this is applicable is Yme, which we know only need phase 4 operations. Therefore we removed the possibility for the MODU to be present at, or transported to and from, Yme, since the MODU is only applicable for phase 2 operations.

In addition, we included Constraints (8.1.3) that states that if a vessel is present in one location at a given point in time, it must be present in a location in the next period as well:

$$\gamma_{fkt} - \sum_{z \in \mathcal{F}} \gamma_{zkt+1} \leq 0, \qquad \forall f \in \mathcal{F}, k \in \mathcal{R}, t \in \mathcal{T} \mid t+1 \in \mathcal{T} \tag{8.1.3}$$

At first sight, one may think that these constraints might be unnecessary due to the already included Constraints (6.3.6). The addition of these constraints lead however to a better performance of the model when we ran test cases.

When we ran TBC1, we wanted to include the possibility for of P&A in the years 2016-2018 even though we knew that the only wellbores included in the run were wellbores located in fields whose optimal shut down time was 2016 or 2017. This was an attempt to make the model flexible such that some operations could be postponed in order to reduce the risk of forcing operations to be performed in months where the WOW factor could increase rental time of the vessels. We suspect that this inclusion of an extra year contributed to an increase in run-time. Therefore, despite risk of losing flexibility, we removed this possibility, and only allowed wellbores to be P&A'ed within the time horizon of determined by the optimal shut down times found in SBC2. In general, the choice of time windows and the requirement that all wellbores within this time horizon must be P&A'ed is a weakness of the model, which is discussed in Chapter 11.

8.2 Improved model - TBC1IM

In Table 8.3, we provide the computational results from running TBC1 and the improved model, TBC1IM.

Table 8.3: Computational results from TBC1 and TBC1IM with improvements. Objective function values in [MUSD]

Statistics		**TBC1**	**TBC1IM**
Constraints	Originally	6 653	3 632
	Presolved	4 019	2 183
Variables	Originally	4 587	4 410
	Presolved	3 209	1 724
Global entities	Originally	3 561	1 167
	Presolved	3 101	1 012
Run-time		47 575.3s	158.4s
Objective value		143.4	156.5
Optimality gap		4.55%	0%

We observe that the run time was reduced drastically. The number of variables, constraints and global entities have been significantly reduced, probably due to a combination of the exclusion of 2018 as possible P&A period and the aforementioned improvements. In Table 8.4, we show the numerical results from running TBC1IM.

Table 8.4: Numerical results from TBC1IM [USD]

Cost Type	**TBC1IM**
P&A cost	90 451 000
Idle time cost	26 574 000
Mobilisation cost	11 500 000
Travel cost	17 975 000
Change cost	10 000 000
Total	**156 500 000**

The largest proportion of the total cost are related to the actual P&A activity. The idle time cost represent the rental of the resource when it is not used for P&A purposes. This is an important figure, because it tells us that our approach with treating time periods as discrete and operating with a time resolution in months provide some challenges regarding how realistic results we are able to obtain from the model. Our assumption that if a vessel is in use in one time period, it has to be rented in all days in that period, combined with the constraints that restrict a vessel from being present in several fields in the same time period, and the addition of Constraints (8.1.1)-(8.1.2), results in high idle time cost.

Table 8.5 provides information on the optimal P&A time for each field, wellbore and phase, and which vessel is used for the different operations.

Table 8.5: Coordination of vessels TBC1IM

Field	**Wellbore**	**Phase**	**Vessel**	**Month**	**Year**
Yme	9/2-D-1	4	LCV	September	2016
Yme	9/2-D-2	4	LCV	September	2016
Yme	9/2-D-3	4	LCV	September	2016
Rev	15/12-C-1 AH	1	RLWI	May	2017
Gaupe	15/12-E-1 H	1	RLWI	June	2017
Gaupe	15/12-E-1 H	2	MODU	June	2017
Gaupe	6/3-A-1 H	1	RLWI	June	2017
Gaupe	6/3-A-1 H	2	MODU	June	2017
Rev	15/12-C-2 H	1	RLWI	July	2017
Rev	15/12-C-2 H	2	MODU	July	2017
Rev	15/12-D-1 H	1	RLWI	July	2017
Rev	15/12-D-1 H	2	MODU	July	2017
Rev	15/12-C-1 AH	2	MODU	August	2017
Rev	15/12-C-1 AH	3	RLWI	August	2017
Rev	15/12-C-1	4	RLWI	August	2017
Rev	15/12-C-2 H	3	RLWI	August	2017
Rev	15/12-C-2 H	4	RLWI	August	2017
Rev	15/12-D-1 H	3	RLWI	August	2017
Rev	15/12-D-1 H	4	RLWI	August	2017
Gaupe	15/12-E-1 H	3	RLWI	September	2017
Gaupe	15/12-E-1 H	4	RLWI	September	2017
Gaupe	6/3-A-1 H	3	RLWI	September	2017
Gaupe	6/3-A-1 H	4	RLWI	September	2017

All P&A operations are being performed during the spring, summer and autumn months where the WOW factor are lowest. The reason why we cannot fit all operations in the months where the WOW factor is lowest (June and July) is because long durations of the P&A operations forces some operations to be performed in periods with higher WOW factor. LCV is only used in Yme, but could have been used for all phase 4 operations on the other fields as well. But since the RLWI already has mobilised to perform phase 1 in Rev and Gaupe, it is better to take advantage of the presence of the RLWI than to rent the LCV in more than one period or mobilise the vessel between Yme and the other fields. Although P&A durations are lower during the summer due to lower WOW factor, the wellbores in Yme is being P&A'ed in September. However, since the durations of the phase 4 operations are so short, the total time spent in Yme will not exceed 30 days. Since the idle time cost will incur anyway, it does not matter if the P&A operations in Yme are performed during the summer or winter.

Another interesting finding is that for the Gaupe field, which has optimal shut down time in 2016 according to the SBC2, all P&A operations are performed in 2017, despite the fact that we have introduced a cost associated with choosing a year for P&A that deviates from the optimal year found in the SBC2. This shows the potential in cost savings associated with exploiting that a vessel has already mobilised, and will be subject to high rental costs once it has been rented. Using our input data, we see that there should be economic incentives for operators to plan for P&A operations in collaboration rather than planning for each field individually. Table 8.6 shows the movement of vessels in the TBC1IM.

Table 8.6: Movement of vessels TBC1IM

Vessel	**From**	**To**	**Month**	**Year**
LCV	Port	Yme	September	2016
LCV	Yme	Port	September	2016
RLWI	Port	Rev	May	2017
MODU	Port	Gaupe	June	2017
RLWI	Rev	Gaupe	June	2017
RLWI	Gaupe	Rev	July	2017
MODU	Gaupe	Rev	July	2017
MODU	Rev	Port	August	2017
RLWI	Rev	Gaupe	September	2017
RLWI	Gaupe	Port	September	2017

Both the MODU and RLWI are transported between fields instead of being transported back to the port before a new well and/or field is being P&A'ed. We also see that the RLWI is transported between Rev and Gaupe several times, which suggest that collaboration of vessel rental is the cost optimal choice.

8.3 Time Horizon of Three Years - TBC2

Based on the aforementioned improvements of the model, we ran the final tactical model with a time horizon of three years. Extending our time horizon to three years resulted in inclusion of the field Jette. Table 8.7 shows these fields' optimal shut down according to the SBC2, number of wellbores and total number of phases required.

Table 8.7: Fields included in TBC2

Field	**Shut down SBC2**	**Wellbores**	**Phases**
Gaupe	2016	2	6
Jette	2018	3	6
Rev	2017	4	9
Yme	2016	3	3
Total		**12**	**24**

In Table 8.8, the computational results from running the TBC2 is presented, together with the statistics from the TBC1IM for comparison.

Table 8.8: Computational results from TBC1IM and TBC2. Objective fuction value in [MUSD].

Statistics		**TBC1IM**	**TBC2**
Constraints	Originally	3 632	7 567
	Presolved	2 183	5 023
Variables	Originally	4 410	8 076
	Presolved	1 724	3 959
Global entities	Originally	1 167	2 301
	Presolved	1 012	2 119
Run-time		158.4s	37 137.5s
Objective value		156.5	226.5
Optimality gap		0%	0%

The inclusion of one extra field with three wellbores and six phases and one year extra resulted in a run time of 37 137.5 seconds, which is large increase compared with the TBC1IM. However, we observe that we obtain a lower runtime for TBC2 than for TBC1. In Table 8.9,we present the cost of the P&A campaign together with the results from TBC1IM:

Table 8.9: Numerical results from TBC1IM and TBC2 [USD]

Cost Type	**TBC1IM**	**TBC2**
P&A cost	90 451 000	122 098 250
Idle time cost	26 574 000	29 216 750
Mobilisation cost	11 500 000	19 000 000
Travel cost	17 975 000	36 850 000
Change cost	10 000 000	20 000 000
Total	**156 500 000**	**226 500 000**

As expected, all cost types increase. However, the idle time cost does not increase by that much, which might be because the vessels are travelling more and thus filling the time periods with travel rather then idle time. Table 8.10 shows the coordination of vessels to perform different phases on different wellbores.

Table 8.10: Coordination of vessels TBC2

Field	**Wellbore**	**Phase**	**Vessel**	**Month**	**Year**
Yme	9/2-D-1	4	LCV	November	2016
Yme	9/2-D-2	4	LCV	November	2016
Yme	9/2-D-3	4	LCV	November	2016
Rev	15/12-C-1 AH	1	RLWI	May	2017
Rev	15/12-C-1 AH	2	MODU	June	2017
Rev	15/12-C-2 H	1	RLWI	June	2017
Rev	15/12-D-1 H	1	RLWI	June	2017
Rev	15/12-D-1 H	2	MODU	June	2017
Gaupe	6/3-A-1 H	1	RLWI	July	2017
Gaupe	6/3-A-1 H	2	MODU	July	2017
Gaupe	15/12-E-1 H	1	RLWI	July	2017
Gaupe	15/12-E-1 H	2	MODU	July	2017
Gaupe	15/12-E-1 H	3	RLWI	August	2017
Gaupe	15/12-E-1 H	4	RLWI	August	2017
Gaupe	6/3-A-1 H	3	RLWI	August	2017
Gaupe	6/3-A-1 H	4	RLWI	August	2017
Jette	25/8-D-1 AH	1	RLWI	May	2018
Jette	25/8-D-1 AH	2	MODU	June	2018
Jette	25/8-D-1 AH	3	RLWI	June	2018

Field	Wellbore	Phase	Vessel	Month	Year
Jette	25/8-E-1 H	1	RLWI	June	2018
Jette	25/8-E-1 H	2	MODU	June	2018
Jette	25/8-E-1 H	3	RLWI	June	2018
Rev	15/12-C-1 AH	3	MODU	July	2018
Rev	15/12-C-1	4	RLWI	July	2018
Rev	15/12-C-2 H	2	MODU	July	2018
Rev	15/12-C-2 H	3	RLWI	July	2018
Rev	15/12-C-2 H	4	RLWI	July	2018
Rev	15/12-D-1 H	3	RLWI	July	2018
Rev	15/12-D-1 H	4	RLWI	July	2018
Jette	25/8-D-1	4	LCV	October	2018
Jette	25/8-E-1 H	4	LCV	October	2018

As before, most of the operations are gathered around the summer months, except when the LCV is used. The reason for this is the same as in the TBC1IM case. We also observe that Gaupe and Rev chooses to postpone operations to 2017 and 2018, respectively, despite the changing costs. Here we also observe that there might be economic incentives for collaborative planning. When coordinating resources across fields, one is able to reduce the mobilisation and total rental costs by taking advantage of the fact that other fields are being P&A'ed during the time horizon. Another interesting finding is that the plan has changed for the fields that are included in both TBC1IM and TBC2. This suggest that when planning for P&A operations, one need to take into account that the time horizon chosen might influence the decisions. In Table 8.11, we record the movement of vessels in the TBC2.

Table 8.11: Movement of vessels in TBC2

Vessel	From	To	Month	Year
LCV	Port	Yme	Nobember	2016
LCV	Yme	Port	November	2016
RLWI	Port	Rev	May	2017
MODU	Port	Rev	June	2017
MODU	Rev	Gaupe	July	2017
RLWI	Rev	Gaupe	July	2017
MODU	Gaupe	Port	July	2017
RLWI	Gaupe	Port	August	2017
RLWI	Port	Jette	May	2018
MODU	Port	Jette	June	2018
RLWI	Jette	Rev	July	2018
RLWI	Rev	Port	July	2018
MODU	Jette	Rev	July	2018
MODU	Rev	Port	July	2018
LCV	Port	Jette	October	2018
LCV	Jette	Port	October	2018

We still observe that vessels are moving between fields, which means that the benefits of taking advantage of a vessel's location is bigger than the costs associated with changing P&A year.

8.4 Conclusion Tactical Level

The results from running the different versions of the tactical model, based on our data, can be summarised as follows:

- Reduction of binary variables lead to lower run-time of the model, but at the expense of flexibility in decisions regarding the period of vessel transport.
- The main costs are related to the actual P&A operations, but a considerable amount of costs are related to movement of resources. Assuming that a vessel must be rented monthly, there are significant idle time costs.
- Considering a time resolution in months leads to challenges regarding how well the model represents reality. The combination between low time resolution in discretisation of time an large variations in durations may suggest that the tactical model is not well suited for scheduling purposes.

- In general, P&A operations should be gathered around summer months to take advantage of low WOW factor.
- When a vessel is mobilised, it is sometimes better to continue using this vessel for other P&A operations rather than mobilising another vessel even though the rental and mobilisation cost of the other resource are lower.
- Taking advantage of the current locations of vessels gives incentives to coordinate multi-well campaigns.
- With more realistic data on WOW factors, mobilisation costs and cost associated with changing the year of P&A, we believe that the model can provide some interesting results regarding cooperation in P&A related activities.
- When imposing that all wellbores must be P&A'ed within the planning horizon, we lose the flexibility to consider other possibly better alternative times for P&A. For instance, it might be better to postpone P&A of wellbores in Jette to 2019, but the model does not allow for considering this alternative.

Chapter 9

Results Operational Level

The focus in this thesis has been on the strategic and tactical level. Therefore, not much time has been spent on developing an efficient operational model. We developed a simple operational model, and ran small test cases in order to evaluate whether the model could (with necessary improvements and real data set) provide valuable results. This chapter, therefore, will present only an example of the operational model. We reduced the durations of P&A operations and travel times by 50% in order to reduce the time horizon to only two months, June and July. We observed that when running the model for several months with the original input on durations, the model became very hard to solve. We have not focused on improvements of the operational model. Despite this, we believe that we were able to obtain interesting results.

We included Constraints 9.0.1 that states if a vessel is present in a location, it must be present in a location the next day. This was included because the model performed better as far as run-time is concerned (the same constraints was added in the tactical model).

$$\gamma_{fkt} - \sum_{z \in \mathcal{F}} \gamma_{zkt+1} \leq 0, \qquad f \in \mathcal{F}, b \in \mathcal{B}_f, k \in \mathcal{R}, t \in \mathcal{T} \mid t+1 \in \mathcal{T} \qquad (9.0.1)$$

In Section 9.1, a multi-well campaign schedule for 2016 is given. Then, in Section 9.2, we look at the year 2017. We conclude the chapter with a short summary of the findings in Section 9.3. Table 9.1 lists the model runs for the operational model.

Table 9.1: Different runs of the operational model

Run Name	Constraints/objective function	Year
OBC1	(6.6.1)-(6.6.11), (9.0.1)/(6.6.12)	2016
OBC2	(6.6.1)-(6.6.11), (9.0.1)/(6.6.12)	2017

9.1 Multi-Well Campaign 2016 - OBC1

First, we consider subsea wellbores located in fields whose optimal shut down time according to SBC2 was 2016, i.e. wellbores in Yme and Gaupe. In Table 9.2, we show the coordination of vessels and the date for execution of each phase.

Table 9.2: Coordination of vessels in OBC1

Field	Wellbore	Phase	Vessel	Date	Duration
Gaupe	15/12-E-1 H	1	RLWI	June 6	8
Gaupe	6/3-A-1 H	1	RLWI	June 14	8
Gaupe	15/12-E-1 H	2	MODU	June 16	6
Gaupe	6/3-A-1 H	2	MODU	June 22	6
Gaupe	15/12-E-1 H	3	RLWI	June 23	3
Gaupe	15/12-E-1 H	4	RLWI	June 26	1
Gaupe	6/3-A-1 H	3	RLWI	June 28	3
Gaupe	6/3-A-1 H	4	RLWI	July 1	1
Yme	9/2-D-2	4	RLWI	July 4	1
Yme	9/2-D-3	4	RLWI	July 5	1
Yme	9/2-D-1	4	RLWI	July 6	1

It is difficult to compare the results from this example with the results obtained from the tactical model. However, we observe that a vessel now can be present in both fields in the same month, which is more realistic than the results from the tactical model. In the operational model we avoid the weakness of obtaining unrealistic idle time for vessels, because time resolution is in days rather than months. In Table 9.3, the movement of vessels are recorded.

Table 9.3: Movement of vessels in OBC1

Vessel	From	To	Start date	Duration
RLWI	Port	Gaupe	June 3	3
MODU	Port	Gaupe	June 13	3
MODU	Gaupe	Port	July 28	3
RLWI	Gaupe	Yme	July 2	2
RLWI	Yme	Port	July 7	2

We see that the RLWI moves from Gaupe directly to Yme rather than being demobilised back to the port, which indicates that coordination of vessels between fields is the cost optimal alternative.

9.2 Multi-well campaign 2017 - OBC2

We also ran the model for the wellbores located in fields whose optimal shut down time according to SBC2 was 2017. The only field to which this applies was Rev. We therefore chose to include Jette, which according to NPD is expected to stop production late in 2016 (in SBC2, we found that optimal production stop time was 2017, and shut down time 2018). In Table 9.4, we show the coordination of vessels and the date for execution of each phase.

Table 9.4: Coordination of vessels OBC2

Field	Wellbore	Phase	Vessel	Date	Duration
Jette	25/8-D-1 AH	1	RLWI	June 5	8
Jette	25/8-D-1 AH	2	MODU	June 13	6
Jette	25/8-E-1 H	1	RLWI	June 13	8
Jette	25/8-D-1 AH	3	MODU	June 13	4
Jette	25/8-E-1 H	2	MODU	June 23	6
Rev	15/12-C-2 H	1	RLWI	June 24	8
Jette	25/8-E-1 H	3	MODU	June 29	4
Rev	15/12-D-1 H	1	RLWI	July 2	8
Rev	15/12-C-2 H	2	MODU	July 6	6
Rev	15/12-C-1 AH	1	RLWI	July 10	8
Rev	15/12-D-1 H	2	MODU	July 12	6
Rev	15/12-C-1 AH	2	MODU	July 18	6
Rev	15/12-D-1 H	3	RLWI	July 18	3

Field	Wellbore	Phase	Vessel	Start date	Duration
Rev	15/12-D-1 H	4	RLWI	July 21	1
Rev	15/12-C-2 H	3	RLWI	July 22	3
Jette	25/8-E-1 H	4	LCV	July 24	1
Jette	25/8-D-1	4	LCV	July 25	1
Rev	15/12-C-1 AH	3	RLWI	July 25	3
Rev	15/12-C-1	4	RLWI	July 28	1
Rev	15/12-C-2 H	4	RLWI	July 29	1

Operations are conducted immediately after each other in sequence in order to reduce the total rental time. In Table 9.5, the movement of vessels are recorded.

Table 9.5: Movement of vessels in OBC2

Vessel	From	To	Start date	Duration
RLWI	Port	Jette	June 2	3
RLWI	Jette	Rev	June 21	3
RLWI	Rev	Port	July 30	3
MODU	Port	Jette	June 10	3
MODU	Jette	Rev	July 3	3
MODU	Rev	Port	July 24	3
LCV	Port	Jette	July 21	3
LCV	Jette	Port	July 26	3

Vessels are moving between fields before moving back to port, which suggest that vessel rental should be planned in collaboration. In Chapter 10, Section 10.3, we will present a numerical result from another multi-well campaign together with different alternative well campaigns for Gaupe and Rev to look at the differences in total costs.

9.3 Conclusion Operational Level

Our findings from running the operational model can be summarised as follows:

- Time resolution in days and horizon of several months lead to difficulties in solving the operational model.

- With a higher time resolution, we are able to better represent a day-to-day schedule that does not suffer from the shortcomings of the tactical model, particularly related to the unrealistic idle time of vessels.
- Our results indicate that collaboration in planning for P&A operations is better than planning for each well or each field independently.

Chapter 10

Sensitivity Analysis

In this chapter, we look at some of many interesting sensitivity analyses that may provide valuable insights on how our results presented in chapters 7, 8 and 9 may or may not change given that we use different inputs in our models. First, in Section 10.1 we run the SBC2 with values on minimum and maximum durations obtained from Chapter 5 with the aim to see how shut down decisions might be different from the most likely durations case. Then, in Section 10.2, we investigate the effects of running the TBC1IM with 20% and 50% reduction in durations of P&A operations. Lastly, in Section 10.3, we compare a multi-well campaign solved by the operational model with other alternatives in order to investigate cost differences. We conclude this chapter with a short summary in Section 10.4. In Table 10.1, we list the runs used in the analysis.

Table 10.1: Runs in the sensitivity analysis

Run Name	**Constraints/objective function**	**Comments**
SS1	(6.1.1)-(6.1.14)/(6.1.16)	Change in shut down costs. No temporary shut down allowed.
TS1	(6.3.1)-(6.3.9), (6.3.11)-(6.3.19), (8.1.1)-(8.1.3)/(6.3.20)	20% reduction in durations.
TS2	(6.3.1)-(6.3.9), (6.3.11)-(6.3.19), (8.1.1)-(8.1.3)/(6.3.20)	50% reduction in durations.
OBC3	(6.6.1)-(6.6.11), (9.0.1)/ (6.6.12)	Multi-well campaign for Rev and Gaupe.
OS1	(6.6.1)-(6.6.11), (9.0.1)/ (6.6.12)	Planning for fields independently.
OS1	(6.6.1)-(6.6.11), (9.0.1)/ (6.6.12)	Planning for wells independently.

10.1 Effects on Using Different Shut Down Cost Inputs - SS1

In Chapter 5, Section 5.2, we presented several different cost estimates for each field distributed on whether we operate with minimum, most likely and maximum values of durations and the choice of different vessels to perform the P&A operations. In this section, we will use minimum and maximum values for durations and consider the same use of technology and vessels as in the SBC2 (i.e. we look at the Min ML and Max ML cases in addition to ML ML). The reason for excluding different vessels and techologies from this scenario analysis is that our hypothesis based on results illustrated in Figure 5.3 was that the costs were most sensitive to the duration of P&A. Table 10.2 shows the results from these runs.

Table 10.2: SBC2 with different shut down costs [MUSD].

Scenario	**Income**	**Shut down costs**	**OPEX**	**Total Profits**
Minimum	621 349	-12 445	-150 531	458 373
Most Likely	621 690	-17 122	-150 971	453 597
Maximum	621 877	-22 391	-151 226	448 259

We see that the main determinant of the objective function value (total profits) are changes in shut down costs. When investigating the change in shut down times when running the different scenarios, we found that in the Min ML case, only eight fields changed its optimal shut down time, with an average of 1.5 years back in time. For these fields, the biggest change was -3 years and the smallest was -1 year. No changes in optimal shut down time to the future was observed. For the maximum cost scenario, we observed the opposite. Here, eight fields (not all the same as in the minimum cost scenario), postponed shut down time farther into the future, and none changed the shut down time to an earlier year, compared to the most likely scenario. The biggest change was +2 years, and the smallest +1 year, and the average was 1.25 years. If costs are reduced, the effect from the discount rate will also reduce. For some fields, the gains of postponing P&A will not be enough to justify continuing producing with losses in order to exploit this effect. The opposite argument applies for the maximum cost case: When costs increase, the effect from the discount rate will be greater, which gives incentives for further postponement.

Although we observe large changes in shut down costs for the different scenarios, the optimal shut down time does not change notably for the large proportion of the fields. Thus, in our deterministic approach we can conclude that the strategic shut down decision is not particularly dependent on the durations of the P&A operations. We believe changes in production, petroleum prices, or other costs may have a greater impact on fields' shut down time decisions, as we observed in the results from the real options model, presented in Chapter 7, Section 7.5.

10.2 Reducing P&A Time in the Tactical Model - TS1 and TS2

If technology advances such that P&A operations might be executed faster, our hypothesis is that more wellbores can be P&A'ed within the same period such that total duration and costs are reduced. We want to investigate how much the total costs decreases, and how the schedule is affected. We use the TBC1IM as basis for this analysis. By reducing durations of P&A operations times by 20% and then 50%, we obtained numerical results given in Table 10.3 (we also include results from TBC1IM for comparison purposes). These runs are denoted TS1 and TS2, respectively.

Table 10.3: Numerical results for TS1, TS2 and TBC1IM [MUSD]

Cost Type	**TS1**	**TS2**	**TBC1IM**
P&A cost	69.771	43.607	90.451
Idle time cost	27.559	16.073	26.574
Mobilisation cost	12.000	9.500	11.500
Travel cost	24.170	13.820	17.975
Change cost	0	10.000	10.000
Total	**133.500**	**93.000**	**156.500**
% of TBC1IM	**85.3%**	**59.4%**	**100%**

As expected, the total costs reduces. However, due to our modelling, we do not see the effects clearly in TS1. In TS2, where we reduced durations by 50%, all cost types except the costs associated with changing year of P&A has been reduced notably. The reduction in execution time not only reduced the costs related to the actual execution of P&A operations, but it also reduced idle time costs by approximately 10 MUSD. If execution time reduces by a large percentage, the tactical model is able to find solutions where it fills up a month with more P&A related work. We observed in TS2 that all operations could be executed during the summer months, which is the cheapest due to the low WOW factor.

10.3 Difference Between Planning Independently and Collaborating - OS1, OS2

On of the main goals with the ECOPA project is to investigate the effect of collaborating in planning for P&A operations in order to reduce costs.

In this section, we will look at two cases: (1) solving the operational model for each field independently (denoted OS1), and (2) solving the operational for each well independently (denoted OS2), and compare the cost obtained from this with the costs obtained from a run where we assumed that Rev and Gaupe were to be P&A'ed in 2016 (We chose this case in order to include many wellbores, such that the effects would become more apparent. This run is denoted OBC3). This way, we can show how the operational model can be used for comparing the costs of a different campaigns. The monetary results should not be in any way interpreted as realistic, but the differences between them might give some insight on the possible gains from collaborating.

For simplicity, we solve the OS1 for each field independently, and add the results together. This is a simplification, because we assume that the vessels are available for both fields in the same period. In reality, we would expect that the resulting schedule would increase the total time used, which could lead to some operations being performed in months where the WOW factor is higher, which would lead to even higher rental costs of the resources since the durations have increased. However, for this example we deem it sufficient to solve the model for each field and add these together. The same approach is used for solving the OS2, only here we are solving the model for each well and adding these together to obtain the total costs. This means that the true costs associated with planning for fields and wells independently should perhaps be adjusted upwards. In Table 10.4, we show the numerical result for these cases together with the numbers obtained from the multi-well campaign for Rev and Gaupe (the schedule for this case is not presented).

Table 10.4: Results from planning for fields independently. OBC3, OS1 and OS2. [USD]

Cost Type	**OBC3**	**OS1**	**OS2**
Rental cost	57 650 000	62 700 000	96 000 000
Mobilisation cost	11 500 000	10 000 000	25 000 000
Total	**69 150 000**	**72 700 000**	**121 000 000**
% Increase from OBC1		**5.1%**	**75.0%**

We see that the cost increases both for OS1 and OS2. The largest increase is observed for OS2, when we plan for each well independently. Rental cost increases because the RLWI has to wait for the MODU to perform its operations before it can execute phases 3 and 4. In the multi-well campaign, the vessels could move to another well once they have finished operations on one well. Thus, the increase in rental costs are actually due to idle time costs for the vessels.

Although only an example, this shows that there might be huge savings from planning operations together rather than planning for P&A for each field or each well independently.

10.4 Conclusion Sensitivity Analysis

The findings from this chapter can be summarised in short as follows:

- Shut down decisions are not especially sensitive to variations in durations.
- Reduction in execution time allows more operations to be performed in cost-optimal time periods.
- Planning P&A operations for several wells and across fields may lead to huge savings compared to planning for fields and wells independently.

Chapter 11

Discussion

In this chapter, we begin in Section 11.1 with a discussion on the different models' inter-dependencies and challenges associated with decomposing a cost analysis of P&A operations in several levels. Then, we discuss each approach and model covered in this thesis in terms of relevance for different actors associated with the Norwegian petroleum industry in Section 11.2.

11.1 Discussion on Planning Levels

In Chapter 1, Section 1.2, we distinguished between three different planning levels that has been used throughout this thesis. This section is meant to provide insights on the interlink between these planning levels in the context of cost analysis of P&A operations on the Norwegian Continental Shelf using mathematical programming, and shed light on some of the advantages and disadvantages by decomposing the holistic cost analysis into the strategic, tactical and operational level.

11.1.1 The Strategic and Tactical Level

In our approach, the strategic model's results were used as basis for the tactical and operational model. This approach requires that the results from the strategic model is a good approximation on the shut down time in order to obtain realistic resource allocation schedules. As we observed when comparing the deterministic approach with the stochastic approach in the real options model, the expected optimal shut down time could deviate by several years if we included uncertainty in oil prices. We have also seen some inconsistencies with publicly available information on planned shut down times and results from our strategic model due to e.g. shortages in data availability. Despite the existence of possible sources of error regarding the results associated with optimal shut down time, we believe that since the tactical model is meant to apply for only a few years in the future, real information on shut down plans should be fairly reliable. Therefore, the tactical model does not necessarily suffer from potential unreliable results obtained from the long term strategic approach if reliable data on a short time horizon has been obtainable.

We based our high level cost estimates on a predetermined number of combinations of durations and vessel choice for performing different phases. Although the tactical model is more flexible regarding the choice of which resources to use, we do not believe that this necessarily represents a challenge regarding the inter-link between the strategic and tactical level. We observed that when changing the duration input data on the strategic model, the optimal shut down decisions did not change notably. As durations represented the biggest difference in the cost estimates and the differences in shut down times were so small, we believe that changes in vessels used for P&A operations would not result in notable changes in optimal shut down time either (given the vessel alternatives we have worked with). In short, although the tactical model is more flexible in the choice of vessels, we do not believe that this difference between the strategic and tactical level give rise to considerable inconsistencies.

The tactical model operates with a combination between discrete and continuous time. The reason why a time resolution in months was chosen was that the problem became unsolvable if we used a time resolution of days or weeks. This results in some challenges regarding how well the model represent reality. Since durations of phases span from only a one day to almost a month (if we take into account the WOW factor) combined with the requirement that a vessel can only be present at one location during a month results in inefficiencies in the schedule and possibly sub-optimal results compared to a model where the time resolution is in days. In order to guarantee time feasibility and to correctly record the movement of vessels, while keeping the model solvable for big data instances, we needed this compromise.

Another challenge with the tactical model is that when we require that all wellbores that belongs to fields whose optimal shut down time lies within the chosen time horizon must be P&A'ed, we lose the flexibility of allowing wellbores to be P&A'ed outside this time horizon, which may be a better alternative. One possible remedy to this problem is to solve the tactical model for different years to investigate whether operations should be included in other time horizons.

11.1.2 The Tactical and Operational Level

The main determinant of how well the tactical model can represent reality is the durations of P&A operations and travel times for vessels. We observed that although we were able to obtain a coarse resource allocation schedule for three years, the idle time on vessels were unrealistically high.

We believe that the tactical model can provide some interesting insights on whether wells in a field should be P&A'ed in combination with other P&A operations of other wells, and to obtain insights on how resource scarcity and long durations influence the time of year the P&A operations should be conducted. However, we do not believe that it should function as a model for detailed planning of P&A operations. Due to high rental costs, it is of utmost importance that the model used for scheduling purposes are allowed to make decisions on a day-to-day level in order to minimise the total cost of a well campaign.

In order to establish a well functioning model for scheduling operations and coordinating resources on a day-to-day level, we need to operate with a time window that allow us to discretise time in days (or construct a model with continuous time, as we did in the tactical VRP model). Therefore, the tactical model is in fact very important in order to obtain a planning horizon that can be used as a time window in which the operational model can be applied. However, if the results from the tactical model is not reliable, this would possibly lead to sub-optimal results for the operational model as well.

11.1.3 The Strategic and Operational Level

There are also inter-links between the strategic and operational level. The high level cost estimate was based on a categorisation of wells based on their statuses and a deterministic estimate of durations. The well statuses give little insight on the complexity of the P&A work required which can influence the duration of the P&A operation. Also, as mentioned in Chapter 1, Section 2.4.3, there are numerous factors that can influence the time used for plugging a well. These "operational" considerations greatly impact the cost estimate of each well, and therefore cost estimation on a field level. Therefore, operational considerations not only influences the credibility of the analyses performed on a tactical level, but also on the strategic level.

11.1.4 Conclusion Discussion on Planning Levels

Based on these considerations and the ones discussed in the previous sections, we believe that in order to use the models developed in this thesis for cost estimation, shut down decision planning, resource allocation and day-to-day P&A planning, the following is of great importance:

- Operational considerations such as well statuses, complexities and durations must be very precise in order to obtain realistic high level cost estimates.
- The results from the strategic level should be interpreted as approximates as results from the tactical level might suggest that deviating from the original optimal solution obtained in the strategic level might lead to better results.
- The results from the tactical level should be interpreted as approximates for the operational level, as optimal decisions on a day-to-day level might deviate from the original optimal solution found in the tactical level.
- The tactical model should be used with caution. Choosing different time periods for the planning horizon might be necessary to investigate which time horizon in which certain fields and/or wellbores should be included.
- Ideally, when solving the operational model, one should iterate back to the tactical and the strategic level to investigate how a potential deviation from the original results influence the decisions in these levels, and measure these costs/benefits against each other in order to validate whether the resource allocation and day-to-day schedule is optimal.

11.2 Relevance of Models

Some of the models might be relevant for some industry actors, but might be less relevant for others. In this section, we will briefly discuss the relevance of each model and approach associated with different industry actors in Norway.

11.2.1 The High Level Cost Estimation Approach

The method used for categorising each well such that an overview of required P&A work and associate a high level cost estimate to this work might be relevant for the Norwegian government and associated directorates (NPD in particular), research institutions and research funding organisations such as the Research Council of Norway. This method can be used to develop a database that can be continuously updated as well and field statuses changes. Such a database can provide insights on the future requirements of P&A work and allow for economic analyses which can motivate for targeted investments and policies regarding P&A. In order for such a database to be valuable, well and field statuses should be continuously updated and categorised in a way that makes it appropriate to use well classification schemes such as Oil and Gas UK (2015). Ideally, the information on each well should be on such fine detail level such that the number of phases and associated complexities can can be included.

11.2.2 The Strategic Model

The strategic model follows naturally the high level cost estimation and well classification. This model can be used to approximate field's optimal shut down time taking into account that the timing of the P&A costs' outflow, gain insights on how connection between fields may impact total profits and shut down decisions, and obtain information on whether a field should be temporary shut down in some periods.

In order for the model to be truly valuable, it should be developed further to include uncertainty in for instance petroleum prices, production levels, depletion rates and technology development. We believe that with these extensions, the model can provide a fairly good approximation on when fields on the NCS should shut down, and also connect the costs to different points in time dependent on when the shut downs are performed. This way, institutions such as the ones mentioned in the previous paragraphs can use these results as basis for even more targeted investments, plans and policies. For petroleum operators, the strategic model can provide insights that can help decision makers in planning for future shut downs in addition to guidance for budgeting.

11.2.3 The Real Options Model

Some of the shortcomings of the strategic model can be handled by a real options model. Our findings suggest that using a stochastic approach for only one state variable gives incentives for postponement of shut down of a field. Such considerations should be taken into account when planning for shut downs. In addition, a more sophisticated real options model can include more stochastic state variables such as gas, NGL prices, recoverable resources, technology, redevelopment of fields, in addition to inclusion of options to temporary shut down and reopen and/or options to switch from oil production to gas production (or vice versa). The real options model can be used as a replacement for, or in combination with, the strategic model. A real options model might be more relevant for petroleum operators than the strategic model as a support for strategic decisions on a firm level.

11.2.4 The Tactical Model

Due to the issues related to the modelling of time as discrete with a time resolution that creates problems as far as reality representation is concerned, the tactical model's usefulness might be restricted. However, it can be used to provide insights on how scarcity in resources can affect the timing and costs related to well campaigns and to give a coarse estimate of an optimal schedule for P&A operations on a medium time horizon. The model can be used to analyse economic effects on for instance reduction in P&A time and availability of resources, and can show that using the vessels that has the lowest rental costs might not always be the cost optimal choice when we take into account the benefits of taking advantage that another appropriate vessel has been mobilised.

The tactical model can be used as a step to obtaining an optimal multi-well campaign schedule. Results from this model give estimates on when during a year it might be optimal to perform P&A operations on the different fields. The model is most relevant for petroleum operators that wish to obtain a medium term overview of the future requirements in resources and to help in planning for more detailed P&A operations. Also, it might be used by several operators in collaboration in order to obtain information on how one should cooperate in order to reduce the costs associated with P&A campaigns. We believe that the model instead of the operational model, but rather as a step for obtaining a time window in which the operational model can be solved.

11.2.5 The Operational Model

When information on estimated times during a year it might be optimal to perform P&A work on wells and fields, and what kind of vessels to be used for these operations, the operational model can be used to provide a day-to-day schedule for the resources needed.

This model can be used by petroleum operators in collaboration to plan for multi-well campaigns with the aim of minimising the time and therefore costs associated with the P&A work. It should be mentioned that in order to increase the usefulness of the model, uncertain factors related to the actual operations (as discussed in Chapter 1, Section 2.4.3) in addition to uncertainty in P&A durations and WOW time should be included in a future model.

11.2.6 Conclusion Relevance of Models

We can summarise the previous sections as follows:

- Models and approaches on the strategic level might be relevant for NPD, research institutions and perhaps operators.
- The tactical model is most relevant for operators and should be used as a coarse estimate on when during a year it might be optimal to P&A wellbores.
- We believe that the operational model is the most relevant model for operators, and is most valuable when it is used in collaboration with other operators to plan for multi-well campaigns that may result in large cost savings compared to planning for each field or each well independently.

Chapter 12

Conclusion and Further Research

This Chapter concludes the thesis with a summary of findings and conclusive remarks in Section 12.1, and suggestion for further research in Section 12.2.

12.1 Conclusive Remarks

We used publicly available information on current development wellbores on the NCS from the NPD and a framework presented by Oil and Gas UK (2015) to obtain a total overview of the number of wellbores and their required P&A phases. We performed a high level cost estimate of the remaining P&A work for 82 fields and 3308 wellbores, which amounted to approximately MUSD 50 000 given that we use most likely values on the durations and an assumed distribution of technologies and vessels to execute the operations. Results from the strategic model showed that these costs are significantly reduced when we take into account that a large proportion of the cash flows will incur in the future. The largest proportion of these costs will incur in the following couple of decades, as many fields must be shut down within this time horizon.

By using these estimates together with forecast data on production levels, petroleum prices and expenses, we estimated the optimal shut down time for all fields on the NCS through different runs of the strategic model. We found that when including shut down cost when investigating the optimal shut down time suggested postponement of production stop for a large proportion of the fields, due to benefits from postponing the cash flow associated with shut downs, despite that the total profits from production were decreased. Although durations of the P&A operations can influence the total P&A cost estimate on a high level, we observed that on average, it did not affect the optimal shut down time notably. When we allowed the oil price to be stochastic, we observed that the shut down decision should be postponed even further.

On the tactical level, we ran several cases that all suggested that P&A operations should be planned in collaboration to obtain efficient use of vessels. However, the model did not perform particularly well as a planning tool for actual multi-well campaigns, due to issues regarding low time resolution which resulted in unrealistic idle time of vessels. We further showed that long durations of P&A operations lead to some wellbores being P&A'ed in periods where durations increase due to the WOW factor. If P&A durations are reduced, one is able to perform more operations during the cheaper summer months.

We used a simple example that showed how the model may provide a day-to-day schedule for two months given that all durations were reduced by 50%, for wellbores candidates for P&A in 2016 and 2017. The results also showed that there are economic incentives for collaboration rather than planning for P&A for each field or each well independently. If improvements are made on the model, or other MP models based on routing problems with time windows combined with project scheduling theory, we believe it can become a good planning tool also for longer time horizons and more wells. The operational model can be used to analyse the economic effect of multi-well campaigns and collaboration and to provide a day-to-day schedule of how resources should be coordinated.

We believe that we have shown that optimisation models can provide powerful tools for performing analyses on many levels regarding P&A operations.

12.2 Suggestion for Further Research

In order for the models presented in this thesis to become part of reliable planning and analysis tools, we believe that it is important to develop the models such that uncertainty can be included. Uncertainty related to petroleum prices, rental rates and availability on vessels and rigs, technology and P&A durations should be integrated in the model formulations.

We have operated with three different types of vessels which has been the only resources we have assumed to be necessary to perform the P&A operations. In reality, many different types of resources are needed to perform these tasks, e.g.

manpower and material. Such considerations should be included in the tactical and operational level.

We have assumed that the vessels used for P&A operations are available for P&A during the entire planning horizon. This is not the case in reality. Future research should include the uncertainty in availability of vessels. Another possibility is to integrate well drilling planning in the models, such that integrated schedules might be obtained. This way, one reduces the risk of planning for P&A operations that might be in conflict with other plans that make use of the same resources.

The inter-link between the planning models has been discussed. Models that integrates several levels such that one is able to obtain results that are optimal for the combination of all levels are desirable.

One of the main challenges we experienced when writing this thesis was the unavailability of relevant information to perform realistic cost analyses. A more detailed and complex database with continuously updated information on well and field statuses, rental rates and other relevant information should be developed.

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Appendices

Appendix A

Durations and Rental Rates

Subsea				
		Durations		
		Min	Most Likely	Max
Phase 1	RLWI	9,08	11,90	14,54
Phase 2	MODU	6,50	8,85	11,54
Methods	ICP	2,00	3,00	4,00
	PWC	3,00	4,00	5,00
	SM	14,00	22,50	33,00
Surface plug	MODU	4,42	5,63	7,50
Surface plug	RLWI	3,13	3,65	4,54
Phase 3	LCV	0,38	0,75	1,08
	RLWI	0,38	0,75	1,08

Platform				
		Durations		
		Min	Most Likely	Max
Phase 1	PLATFORM	9,08	11,90	14,54
Phase 2	PLATFORM	6,50	8,85	11,54
Methods	ICP	2,00	3,00	4,00
	PWC	3,00	4,00	5,00
	SM	14,00	22,50	33,00
Surface plug	PLATFORM	4,42	5,63	7,50
Phase 3	PLATFORM	1,50	3,00	4,33

WOW%	20,00 %	**Daily rates of [USD]**	
NPT%	20,00 %	RLWI	450 000
		MODU	700 000
		LCV	150 000
		Platform	400 000

Figure A.1: Durations and rental rates

Appendix B

Possible Unexpected Events

Table B1: Possible unexpected events for P&A of a single well (Moeinikia et al., 2014).

Unexpected Events	Consequences
Lack of communication between tubing and annulus after punching	Need higher punch, need extra run
Collapsed tubing or casing	Need for specialised equipment and plan to remove collapsed casing, tubing and obstructions
Problem to cut tubing	Need to recut or change tool
Pulling breaks into separate parts when pulling out	Need extra runs
Operational problems have been encountered with perforate, wash, and cement (PWC) technology	Drill cement plug inside casing and check quality of cement behind casing - implement necessary measures

Unexpected Events	**Consequences**
No uncemented casing across the setting interval	Change program: Mill, clean, underream the section, and set a balanced cement plug
When using PWC Technology, there is not additional wellbore length for guns to be left in the hole	Use two or three trips with PWC system, which require additional time
Not able to pull casing	Extra cuts in different sections of casing and need additional runs
Problem to cut casing	Need recut or change tool
Casing breaks into separate parts when pulling out	Need extra runs
Contamination of cement during placement or failure of cement during test	Need to set new plug

Appendix C

Conversions

$$1Sm^3gas = 40MJ$$

$$1MJ = 947.817BTU$$

$$1Sm^3gas = 37.91268cf = 0.03791268kcf$$

$$1000Sm^3gas = 37,91268kcf$$

$$\frac{1USD}{kcf} = \frac{1USD}{\frac{1000}{37.91268}Sm^3}$$

$$\frac{1USD}{kcf} = \frac{37.91268USD}{1000Sm^3}$$

$$\frac{1USD}{kcf} = \frac{1USD}{MMBTU} = \frac{0.03791268USD}{Sm^3}$$

Appendix D

Phase Requirement on the NCS

Table D1: Phases needed on the NCS divided in fields and wellbore types

Field	Type	Wellbores	P1	P2	P3	Total Phases
Tor	Platform	20	15	15	16	46
Alve	Subsea	3	2	2	2	6
Alvheim	Subsea	47	34	34	22	90
Atla	Subsea	1	1	1	1	3
Balder	Platform	27	18	18	19	55
Balder	Subsea	42	24	24	27	75
Brage	Platform	65	39	39	40	118
Brynhild	Subsea	6	4	4	4	12
Bøyla	Subsea	5	3	3	3	9
Draugen	Platform	8	6	6	6	18
Draugen	Subsea	20	16	16	19	51
Edvard Grieg	Platform	5	3	3	3	9
Ekofisk	Platform	281	168	168	193	529
Ekofisk	Subsea	16	16	16	16	48
Eldfisk	Platform	94	53	53	59	165
Embla	Platform	7	7	7	7	21
Fram	Subsea	22	16	16	13	45
Fram H-Nord	Subsea	3	2	2	1	5
Gaupe	Subsea	2	2	2	2	6

Field	**Type**	**Wellbores**	**P1**	**P2**	**P3**	**Total Phases**
Gimle	Platform	5	4	4	3	11
Gjøa	Subsea	21	16	16	13	45
Goliat	Subsea	23	20	20	19	59
Grane	Platform	99	76	76	38	190
Gudrun	Platform	9	7	7	8	22
Gullfaks	Platform	199	127	127	130	384
Gullfaks	Subsea	6	1	1	6	8
Gullfaks Sør	Platform	2	2	2	1	5
Gullfaks Sør	Subsea	82	55	55	53	163
Gungne	Platform	4	3	3	3	9
Gyda	Platform	50	34	34	33	101
Heidrun	Platform	84	55	55	55	165
Heidrun	Subsea	32	21	21	21	63
Heimdal	Platform	12	2	2	11	15
Hod	Platform	13	8	8	8	24
Huldra	Platform	6	6	6	6	18
Hyme	Subsea	4	3	3	2	8
Jette	Subsea	3	2	2	2	6
Jotun	Platform	30	20	20	22	62
Knarr	Subsea	6	6	6	6	18
Kristin	Subsea	15	12	12	14	38
Kvitebjørn	Platform	17	12	12	16	40
Marulk	Subsea	3	2	2	2	6
Mikkel	Subsea	3	3	3	3	9
Morvin	Subsea	5	4	4	5	13
Njord	Subsea	30	16	16	20	52
Norne	Subsea	41	28	28	27	83
Ormen Lange	Platform	1	0	0	1	1
Ormen Lange	Subsea	26	19	19	22	60
Oseberg	Platform	123	72	72	73	217
Oseberg	Subsea	21	14	14	15	43
Oseberg Sør	Platform	51	32	32	29	93
Oseberg Sør	Subsea	19	13	13	14	40
Oseberg Øst	Platform	24	13	13	15	41
Oselvar	Subsea	3	3	3	3	9
Rev	Subsea	4	3	3	3	9
Ringhorne Øst	Platform	6	4	4	4	12
Sigyn	Subsea	3	3	3	3	9
Skarv	Subsea	18	13	13	17	43

Field	Type	Wellbores	P1	P2	P3	Total Phases
Skirne	Subsea	3	2	2	2	6
Skuld	Subsea	12	6	6	8	20
Snorre	Platform	64	45	45	44	134
Snorre	Subsea	50	37	37	39	113
Snøhvit	Subsea	10	10	10	10	30
Statfjord	Platform	225	112	112	124	348
Statfjord	Subsea	3	2	2	2	6
Statfjord Nord	Subsea	14	12	12	12	36
Statfjord Øst	Platform	2	2	2	0	4
Statfjord	Subsea	14	7	7	11	25
Svalin	Platform	3	2	2	1	5
Svalin	Subsea	4	2	2	2	6
Sygna	Subsea	3	3	3	3	9
Tambar	Platform	3	3	3	3	9
Tambar Øst	Platform	2	1	1	1	3
Tordis	Subsea	23	15	15	17	47
Troll	Platform	49	39	39	48	126
Troll	Subsea	449	360	360	131	851
Trym	Subsea	3	2	2	2	6
Tune	Subsea	8	5	5	6	16
Tyrihans	Subsea	35	25	25	13	63
Ula	Platform	30	16	16	18	50
Urd	Subsea	15	11	11	11	33
Vale	Subsea	2	1	1	1	3
Valemon	Platform	13	11	11	12	34
Valhall	Platform	136	91	91	99	281
Varg	Platform	23	9	9	16	34
Vega	Subsea	8	5	5	6	16
Veslefrikk	Platform	47	24	24	24	72
Vigdis	Subsea	41	28	28	29	85
Vilje	Subsea	7	4	4	3	11
Visund	Subsea	48	26	26	30	82
Visund Sør	Subsea	7	4	4	4	12
Volund	Subsea	13	7	7	6	20
Volve	Platform	14	9	9	10	28
Yme	Platform	8	0	0	8	8
Yme	Subsea	3	0	0	3	3
Åsgard	Subsea	85	71	71	66	208
Sleipner	Platform	46	39	39	41	119

Field	**Type**	**Wellbores**	**P1**	**P2**	**P3**	**Total Phases**
Sleipner	Subsea	6	5	5	5	15

Appendix E

Cost Estimate

Table E1: Cost estimation of P&A of fields on the NCS [MUSD] The first row of the table, in columns 2-12, states whether we have use minimum (Min), most likely (ML) or maximum (Max) values for the duration times. Furthermore, in row 2, columns 2-12, there are two letters. The first states whether the surface plug is set with a MODU (M) or RLWI (R), and the second indicates whether the last phase (removing wellhead) is performed by an LCV (L) or RLWI (R).

	Min	Min	Min	Min	ML	ML	ML	ML	Max	Max	Max	Max
Field	**ML**	**MR**	**RL**	**RR**	**ML**	**MR**	**RL**	**RR**	**ML**	**MR**	**RL**	**RR**
Tor	194	194	194	194	272	272	272	272	359	359	359	359
Alve	37	38	36	36	51	51	50	51	67	67	65	66
Alvheim	634	637	613	616	866	871	852	857	1131	1139	1104	1109
Atla	19	19	18	18	26	26	25	25	33	34	33	33
Balder	681	684	666	670	939	945	929	935	1230	1239	1211	1217
Brage	503	503	503	503	705	705	705	705	929	929	929	929
Brynhild	75	75	72	73	102	103	100	101	133	135	130	131
Bøyla	56	56	54	55	77	77	75	76	100	101	98	98
Draugen	376	378	367	369	517	521	510	515	676	683	663	668
Edvard Grieg	39	39	39	39	54	54	54	54	71	71	71	71
Ekofisk	2482	2484	2472	2474	3476	3480	3469	3473	4578	4584	4565	4569

Field	Min ML	Min MR	Min RL	Min RR	ML ML	ML MR	ML RL	ML RR	Max ML	Max MR	Max RL	Max RR
Eldfisk	687	687	687	687	965	965	965	965	1272	1272	1272	1272
Embla	90	90	90	90	126	126	126	126	166	166	166	166
Fram	299	300	289	290	408	411	401	404	533	537	520	523
Fram H-Nord	37	37	36	36	51	51	50	50	66	67	65	65
Gaupe	37	38	36	36	51	51	50	51	67	67	65	66
Gimle	51	51	51	51	71	71	71	71	93	93	93	93
Gjøa	299	300	289	290	408	411	401	404	533	537	520	523
Goliat	373	376	361	363	510	515	502	506	666	673	650	655
Grane	952	952	952	952	1317	1317	1317	1317	1727	1727	1727	1727
Gudrun	91	91	91	91	128	128	128	128	168	168	168	168
Gullfaks	1658	1659	1657	1658	2323	2324	2322	2323	3059	3061	3058	3059
Gullfaks Sør	1052	1058	1019	1025	1438	1450	1414	1427	1878	1896	1834	1846
Gungne	39	39	39	39	54	54	54	54	71	71	71	71
Gyda	437	437	437	437	612	612	612	612	806	806	806	806
Heidrun	1101	1103	1088	1091	1528	1533	1520	1524	2007	2014	1990	1995
Heimdal	32	32	32	32	49	49	49	49	66	66	66	66
Hod	103	103	103	103	144	144	144	144	190	190	190	190
Huldra	77	77	77	77	108	108	108	108	143	143	143	143
Hyme	56	56	54	54	76	77	75	76	100	100	97	98
Jette	37	38	36	36	51	51	50	51	67	67	65	66
Jotun	259	259	259	259	364	364	364	364	480	480	480	480
Knarr	112	113	108	109	153	154	151	152	200	202	195	197
Kristin	224	226	217	219	306	310	301	305	400	405	390	394
Kvitebjørn	158	158	158	158	222	222	222	222	294	294	294	294
Marulk	37	38	36	36	51	51	50	51	67	67	65	66
Mikkel	56	56	54	55	77	77	75	76	100	101	98	98
Morvin	75	75	72	73	102	103	100	102	133	135	130	131
Njord	299	301	289	292	409	413	402	407	534	541	521	525
Norne	523	526	506	509	714	721	702	709	933	942	910	917
Ormen Lange	356	358	344	347	487	492	478	484	636	643	620	625
Oseberg	1190	1192	1182	1183	1658	1662	1652	1656	2180	2185	2169	2172
Oseberg Sør	653	655	645	647	905	908	899	903	1188	1193	1177	1180
Oseberg Øst	169	169	169	169	238	238	238	238	313	313	313	313
Oselvar	56	56	54	55	77	77	75	76	100	101	98	98
Rev	56	56	54	55	77	77	75	76	100	101	98	98
Ringhorne Øst	52	52	52	52	72	72	72	72	95	95	95	95
Sigyn	56	56	54	55	77	77	75	76	100	101	98	98
Skarv	243	245	235	237	332	336	327	331	434	440	423	427
Skirne	37	38	36	36	51	51	50	51	67	67	65	66
Skuld	112	113	109	109	153	155	151	153	200	203	195	197
Snorre	1270	1275	1248	1252	1755	1764	1739	1748	2301	2314	2271	2280
Snøhvit	187	188	181	182	255	257	251	253	333	337	325	328
Statfjord	1489	1490	1488	1488	2090	2090	2089	2089	2754	2754	2752	2752
Statfjord Nord	224	225	217	218	306	309	301	304	400	404	390	393
Statfjord Øst	155	157	151	152	212	215	209	212	277	281	271	274
Svalin	62	63	61	61	86	86	85	85	112	113	110	111
Sygna	56	56	54	55	77	77	75	76	100	101	98	98
Tambar	39	39	39	39	54	54	54	54	71	71	71	71
Tambar Øst	13	13	13	13	18	18	18	18	24	24	24	24
Tordis	280	282	271	273	383	387	377	381	500	506	488	492
Troll	7217	7232	6999	7014	9875	9906	9722	9753	12906	12950	12626	12657
Trym	37	38	36	36	51	51	50	51	67	67	65	66
Tune	93	94	90	91	128	129	126	127	167	169	163	164
Tyrihans	466	468	451	452	636	640	626	629	831	836	812	815

Field	Min ML	Min MR	Min RL	Min RR	ML ML	ML MR	ML RL	ML RR	Max ML	Max MR	Max RL	Max RR
Ula	208	208	208	208	292	292	292	292	384	384	384	384
Urd	205	207	199	200	281	283	276	279	367	370	358	360
Vale	19	19	18	18	26	26	25	25	33	34	33	33
Valemon	142	142	142	142	200	200	200	200	264	264	264	264
Valhall	1179	1179	1179	1179	1654	1654	1654	1654	2180	2180	2180	2180
Varg	121	121	121	121	173	173	173	173	228	228	228	228
Vega	93	94	90	91	128	129	126	127	167	169	163	164
Veslefrikk	309	309	309	309	433	433	433	433	570	570	570	570
Vigdis	523	526	506	509	715	721	703	709	933	943	911	917
Vilje	75	75	72	73	102	103	100	101	133	134	130	131
Visund	486	489	470	473	664	671	653	660	867	877	846	853
Visund Sør	75	75	72	73	102	103	100	101	133	135	130	131
Volund	131	131	126	127	178	180	176	177	233	235	228	229
Volve	117	117	117	117	164	164	164	164	216	216	216	216
Yme	6	6	6	6	12	13	12	13	17	18	17	18
Åsgard	1325	1333	1282	1290	1811	1826	1781	1796	2366	2388	2308	2324
Sleipner	597	598	594	595	834	835	832	833	1098	1099	1094	1095
Total	**34527**	**34621**	**33906**	**33999**	**47722**	**47909**	**47284**	**47472**	**62575**	**62846**	**61755**	**61942**

Appendix F

Results SBC1

Table F1: Results from SBC1: Production stop time without P&A costs - all OPEX are fixed

Field	Model	Forecast	Field	Model	Forecast
Tor	2016	2016	Oseberg	2049	2099
Alve	2027	2032	Oseberg Sør	2051	2055
Alvheim	2034	2035	Oseberg Øst	2050	2050
Atla	2027	2029	Oselvar	2019	2019
Balder	2027	2027	Rev	2016	2016
Brage	2025	2027	Ringhorne Øst	2023	2023
Brynhild	2025	2025	Sigyn	2036	2037
Bøyla	2027	2029	Skarv	2038	2045
Draugen	2031	2031	Skirne	2020	2021
Edvard Grieg	2031	2033	Skuld	2027	2027
Ekofisk	2074	2077	Sleipner	2021	2023
Eldfisk	2064	2064	Snorre	2041	2041
Embla	2052	2059	Snøhvit	2044	2055
Fram	2038	2045	Statfjord	2023	2025
Fram H-Nord	2025	2027	Statfjord Nord	2053	2053
Gaupe	2016	2016	Statfjord Øst	2025	2026
Gimle	2023	2026	Svalin	2027	2028
Gjøa	2028	2030	Sygna	2025	2025
Goliat	2030	2030	Tambar	2021	2022
Grane	2060	2060	Tambar Øst	2020	2021
Gudrun	2030	2032	Tordis	2036	2036

Field	**Model**	**Forecast**	**Field**	**Model**	**Forecast**
Gullfaks	2031	2031	Troll	2099	2099
Gullfaks Sør	2051	2065	Trym	2025	2028
Gungne	2019	2021	Tune	2018	2020
Gyda	2016	2020	Tyrihans	2060	2068
Heidrun	2059	2064	Ula	2028	2028
Heimdal	2016	2016	Urd	2032	2033
Hod	2016	2016	Vale	2017	2017
Huldra	2016	2016	Valemon	2029	2033
Hyme	2038	2039	Valhall	2099	2099
Jette	2017	2017	Varg	2016	2016
Jotun	2016	2016	Vega	2040	2043
Knarr	2021	2021	Veslefrikk	2018	2018
Kristin	2030	2033	Vigdis	2032	2033
Kvitebjørn	2053	2061	Vilje	2030	2030
Marulk	2025	2028	Visund	2053	2068
Mikkel	2071	2081	Visund Sør	2033	2038
Morvin	2053	2053	Volund	2045	2045
Njord	2030	2042	Volve	2016	2016
Norne	2021	2022	Yme	2016	2016
Ormen Lange	2035	2042	Åsgard	2031	2034

Appendix G

Results SBC2

Table G1: Results from SBC2. Shut down times with P&A costs.
PS1=Production stop time from SBC1. PS2=Production stop time from SBC2

Field	PS1	PS2	Diff.	Shut Down
Tor	2016	2016	0	2016
Alve	2027	2030	3	2031
Alvheim	2034	2035	1	2036
Atla	2027	2029	2	2030
Balder	2027	2027	0	2028
Brage	2025	2027	2	2028
Brynhild	2025	2025	0	2026
Bøyla	2027	2028	1	2029
Draugen	2031	2031	0	2032
Edvard Grieg	2031	2031	0	2032
Ekofisk	2074	2077	3	2078
Eldfisk	2064	2064	0	2065
Embla	2052	2054	2	2055
Fram	2038	2045	7	2046
Fram H-Nord	2025	2027	2	2028
Gaupe	2016	2016	0	2016
Gimle	2023	2026	3	2027
Gjøa	2028	2029	1	2030
Goliat	2030	2030	0	2031
Grane	2060	2060	0	2061
Gudrun	2030	2030	0	2031

Field	PS1	PS2	Diff.	Shut Down
Gullfaks	2031	2031	0	2032
Gullfaks Sør	2051	2054	3	2055
Gungne	2019	2020	1	2021
Gyda	2016	2019	3	2020
Heidrun	2059	2054	-5	2055
Heimdal	2016	2016	0	2016
Hod	2016	2016	0	2016
Huldra	2016	2016	0	2016
Hyme	2038	2039	1	2040
Jette	2017	2017	0	2018
Jotun	2016	2016	0	2017
Knarr	2021	2021	0	2022
Kristin	2030	2031	1	2032
Kvitebjørn	2053	2054	1	2055
Marulk	2025	2026	1	2027
Mikkel	2071	2076	5	2077
Morvin	2053	2053	0	2054
Njord	2030	2042	12	2043
Norne	2021	2022	1	2023
Ormen Lange	2035	2036	1	2037
Oseberg	2049	2089	40	2090
Oseberg Sør	2051	2054	3	2055
Oseberg Øst	2050	2050	0	2051
Oselvar	2019	2019	0	2020
Rev	2016	2016	0	2017
Ringhorne Øst	2023	2023	0	2024
Sigyn	2036	2037	1	2038
Skarv	2038	2045	7	2046
Skirne	2020	2020	0	2021
Skuld	2027	2027	0	2028
Sleipner	2021	2022	1	2023
Snorre	2041	2041	0	2042
Snøhvit	2044	2044	0	2045
Statfjord	2023	2025	2	2026
Statfjord Nord	2053	2053	0	2054
Statfjord Øst	2025	2026	1	2027
Svalin	2027	2028	1	2029
Sygna	2025	2025	0	2026
Tambar	2021	2022	1	2023

Field	PS1	PS2	Diff.	Shut Down
Tambar Øst	2020	2021	1	2022
Tordis	2036	2036	0	2037
Troll	2099	2089	-10	2090
Trym	2025	2027	2	2028
Tune	2018	2020	2	2021
Tyrihans	2060	2068	8	2069
Ula	2028	2028	0	2029
Urd	2032	2033	1	2034
Vale	2017	2018	1	2019
Valemon	2029	2030	1	2031
Valhall	2099	2089	-10	2090
Varg	2016	2016	0	2017
Vega	2040	2043	3	2044
Veslefrikk	2018	2018	0	2019
Vigdis	2032	2033	1	2034
Vilje	2030	2030	0	2031
Visund	2053	2054	1	2055
Visund Sør	2033	2038	5	2039
Volund	2045	2045	0	2046
Volve	2016	2016	0	2017
Yme	2016	2016	0	2016
Åsgard	2031	2034	3	2035

Appendix H

Results SBC3

Table H1: Results from running the SBC3. PS = Production stop time, TSD = Temporary shut down, MS = Monitor stop, ME = Monitor end, PSD = Permanent shut down

Field	PS	TSD	MS	ME	PSD
Tor	2016				2016
Alve	2030				2031
Alvheim	2035	2036	2037	2039	2040
Atla	2029				2030
Balder	2027	2028	2029	2031	2032
Brage	2027	2028	2029	2031	2032
Brynhild	2025				2026
Bøyla	2028				2029
Draugen	2031	2032	2033	2035	2036
Edvard Grieg	2031				2032
Ekofisk	2077	2078	2079	2081	2082
Eldfisk	2064	2065	2066	2068	2069
Embla	2054				2055
Fram	2045	2046	2047	2049	2050
Fram H-Nord	2027				2028
Gaupe	2016				2016
Gimle	2026				2027
Gjøa	2029	2030	2031	2033	2034
Goliat	2030	2031	2032	2034	2035
Grane	2060	2061	2062	2064	2065

Field	PS	TSD	MS	ME	PSD
Gudrun	2030				2031
Gullfaks	2031	2032	2033	2035	2036
Gullfaks Sør	2054				2055
Gungne	2020				2021
Gyda	2019	2020	2021	2023	2024
Heidrun	2054				2055
Heimdal	2016				2016
Hod	2016				2016
Huldra	2016				2016
Hyme	2039				2040
Jette	2017				2018
Jotun	2016	2017	2018	2020	2021
Knarr	2021				2022
Kristin	2031	2032	2033	2035	2036
Kvitebjørn	2054				2055
Marulk	2026				2027
Mikkel	2078				2079
Morvin	2053				2054
Njord	2042	2043	2044	2046	2047
Norne	2022	2023	2024	2026	2027
Ormen Lange	2036	2037	2038	2040	2041
Oseberg	2089				2090
Oseberg Sør	2054				2055
Oseberg Øst	2050				2051
Oselvar	2019				2020
Rev	2016				2017
Ringhorne Øst	2023				2024
Sigyn	2037				2038
Skarv	2045	2046	2047	2049	2050
Skirne	2020				2021
Skuld	2027				2028
Sleipner	2022	2023	2024	2026	2027
Snorre	2041	2042	2043	2045	2046
Snøhvit	2044				2045
Statfjord	2025	2026	2027	2029	2030
Statfjord Nord	2053	2054			2055
Statfjord Øst	2026	2027			2028
Svalin	2028				2029
Sygna	2025	2026			2027

Field	PS	TSD	MS	ME	PSD
Tambar	2022	2023			2024
Tambar Øst	2021				2022
Tordis	2036				2037
Troll	2089				2090
Trym	2027				2028
Tune	2020				2021
Tyrihans	2068	2069	2070	2072	2073
Ula	2028	2029	2030	2032	2033
Urd	2033	2034	2035	2037	2038
Vale	2018				2019
Valemon	2030				2031
Valhall	2089				2090
Varg	2016	2017			2018
Vega	2043				2044
Veslefrikk	2018				2019
Vigdis	2033	2034	2035	2037	2038
Vilje	2030				2031
Visund	2054				2055
Visund Sør	2038				2039
Volund	2045				2046
Volve	2016	2017			2018
Yme	2016				2016
Åsgard	2033	2034	2035	2037	2038

Appendix I

Regression Parameters

Table I1: Regression parameters for Brynhild

Year	β	γ_1	γ_2
2024	-32.11	15.31	-0.58280
2023	-0.70	0.79	-0.01862
2022	-0.91	0.69	-0.00179
2021	-0.96	0.67	-0.00075
2020	-0.95	0.67	-0.00074
2019	-1.15	0.69	-0.00087
2018	-1.46	0.69	-0.00069
2017	-1.54	0.68	-0.00031

Table I2: Regression parameters for Svalin

Year	β	γ_1	γ_2
2027	-49.73	1.70	-0.00313
2026	-31.93	1.65	-0.00298
2025	-20.84	1.29	-0.00231
2024	-12.89	0.99	-0.00110
2023	-7.56	0.76	-0.00030
2022	-5.15	0.73	-0.00018
2021	-3.67	0.68	-0.00002
2020	-3.25	0.68	-0.00004
2019	-5.80	0.71	-0.00008
2018	-9.31	0.73	-0.00008
2017	-10.25	0.72	-0.00004

Table I3: Regression parameters for Vigdis field (Values for β and γ_1 are rounded to two decimals, and values for γ_2 to five.

Year	β	γ_1	γ_2
2032	-377.03	2.28	-0.00071
2031	-217.30	2.36	-0.00095
2030	-141.43	1.89	-0.00058
2029	-88.58	1.51	-0.00042
2028	-58.45	1.18	-0.00019
2027	-33.85	1.00	-0.00008
2026	-12.65	0.83	-0.00002
2025	8.38	0.68	0.00013
2024	34.78	0.63	0.00004
2023	52.85	0.44	0.00026
2022	72.34	0.26	0.00043
2021	86.32	0.35	0.00028
2020	97.07	0.29	0.00039
2019	90.94	0.36	0.00031
2018	75.86	0.43	0.00031
2017	61.27	0.45	0.00039

Appendix J

TravelTimes

Table J1: Travel times used in the tactical and operational model. We assume that the port is located in Stavanger, Norway

From	**To**	**Duration**	**From**	**To**	**Duration**
Port	Port	0	OSELVAR	OSELVAR	0
Port	GAUPE	5	OSELVAR	REV	5
Port	JETTE	5	OSELVAR	VALE	12
Port	OSELVAR	7	OSELVAR	YME	3
Port	REV	5	REV	Port	5
Port	VALE	3	REV	GAUPE	1
Port	YME	3	REV	JETTE	5
GAUPE	Port	5	REV	OSELVAR	5
GAUPE	GAUPE	0	REV	REV	0
GAUPE	JETTE	5	REV	VALE	5
GAUPE	OSELVAR	5	REV	YME	3
GAUPE	REV	1	VALE	Port	3
GAUPE	VALE	5	VALE	GAUPE	5
GAUPE	YME	3	VALE	JETTE	2
JETTE	Port	5	VALE	OSELVAR	12
JETTE	GAUPE	5	VALE	REV	5
JETTE	JETTE	0	VALE	VALE	0
JETTE	OSELVAR	10	VALE	YME	10
JETTE	REV	5	YME	Port	3
JETTE	VALE	2	YME	GAUPE	3
JETTE	YME	5	YME	JETTE	5

From	To	Duration	From	To	Duration
OSELVAR	Port	7	YME	OSELVAR	3
OSELVAR	GAUPE	5	YME	REV	3
OSELVAR	JETTE	10	YME	VALE	10
			YME	YME	0