David Semwogerere

Digital Well Planning for Completions

Master's thesis in Petroleum Engineering
Supervisor: Sigbjørn Sangesland, IPT
Co-supervisor: Bjørn Brechan, Equinor
June 2021

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Summary

The current well completion planning process in most operating companies is a manual process involving hands-on approach from one step to another. It is typified by repetitive calculations, meetings and email exchanges for reservoir and subsurface input and a lot of paperwork. This thesis introduces an automated well completion design process based on digitalization of the manual elements of the traditional well completion planning.

Well completion planning has two stages. The first stage is the Basis of Design (BOD) stage where methods and technology are selected based on the well Statement of Requirements (SOR). The second stage is operations planning for deployment of the technology selected in the BOD. These processes take a long time in the current well planning methodology and in light current industry challenges (covid, renewables, falling oil prices), any improvement in efficiency and faster well delivery can go a long way in cost reduction. This can be achieved with digital well planning.

To illustrate how this works, a program was written in Python that automatically selects a sand control strategy at the BOD planning level. The program receives sieve analysis and formation stresses as input data from subsurface, it then considers production requirements from the production team and recommends a sand control strategy.

The thesis further describes a workflow for operations planning in well completion deployment using sand control deployment as an example. This relies on the common sequence of operations based on standards and experience with related equipment and engineering for successful execution of these operations. The challenge however, and possibly an opportunity for future work is how to merge the digital well planning with automation execution on the rig/platform/workover units to allow robotics to read instructions and execute/deploy the completion as required.

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Sammendrag

Den nåværende planleggingsprosessen for brønnkomplettering er i de fleste operatørselskaper en manuell prosess som involverer praktisk tilnærming trinn for trinn. Det er preget av gjentatte beregninger, møter og utveksling av e-post for reservoar og undergrunnsinformasjon og mye papirarbeid. Denne oppgaven introduserer en automatisert designprosess for brønnkomplettering basert på digitalisering av de manuelle elementene som inngår i den tradisjonelle planleggingen av en brønnkomplettering.

Planlegging av brønnkomplettering har to trinn. Den første fasen er basis av design (Basis of Design- BOD) hvor metoder og teknologi velges basert på brønnen kravspesifikasjon (Statement of Requirements- SOR). Den andre fasen er operasjonsplanlegging for distribusjon av teknologien valgt i BOD. Disse prosessene tar lang tid i dagens brønnplanleggingsmetodikk og i lys av nåværende industriutfordringer (covid, fornybar energi, fallende oljepris). Enhver forbedring i effektivitet og raskere brønnleveranse kan bidra til vesentlige kostnadsreduksjoner. Dette kan oppnås med digital brønnplanlegging.

For å illustrere hvordan dette fungerer ble det skrevet et program i Python som automatisk velger en sandkontrollstrategi på BOD planleggingsnivå. Programmet mottar utvalgte data og formasjonsspenninger som inndata fra undergrunnen, og vurderer deretter produksjonskrav fra produksjonsteamet og anbefaler deretter en strategi for sandkontroll.

Som et eksempel, beskriver oppgaven videre en arbeidsflyt for planlegging og operasjon for plassering av en brønnkomplettering for sandkontroll. Dette er en vanlig operasjonssekvens basert på standarder og erfaring med relatert utstyr og konstruksjon for vellykket gjennomføring av slike operasjoner.

Utfordringen, og en mulighet for fremtidig arbeid, er hvordan man kan slå sammen den digitale brønnplanleggingen med automatiseringsutførelsen på riggen / plattformen / workover-enhetene for å tillate robotikk å lese instruksjoner og utføre / arrangere ferdigstillelse etter behov.

Acknowledgements

I would like to thank my supervisor professor Sigbjørn Sangesland at NTNU for aligning my professional and academic interests with this thesis opportunity.

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My father Herbert Katende for supporting me, keeping me grounded and focused on pursuing this master's degree.

Thank you all

David Semwogerere

List of Acronyms

AFE – Authorisation For Expenditure
API – American Petroleum Institute
ASV – Annulus Safety Valve
BHA – Bottom Hole Assembly
CBL – Cement Bond Log
BOD – Basis of Design
CCL – Casing Collar Locator
CFT - Call For Tender
CSD – Completion String Design
CWOP – Completion Well On Paper
DHSV – Downhole Safety Valve
ECD – Equivalent Circulation Density
EOWR – End of Well Report
FIV – Formation Isolation Valve
GP - Gravel Pack
HMI – Human-Machine Interface
HP/HT – High Pressure/High Temperature
HRWP - High Rate Water Pack
HUD – Hold Up Depth
ICD – Inflow Control Device
ID – Internal Diameter
ISO - International Standards Organisation
KPI - Key Performance Indicators
LD - Lay down
MLT - Multilateral Technology
MU - Make Up
MWD - Measurement While Drilling
MTTF - Mean Time To Failure
NCS - Norwegian Continental Shelf
NPT - Non-productive Time
POOH - Pull Out Of Hole
PSD – Particle Size Distribution
PBR – Polished Bore Receptacle
PU – Pick Up
QSHE – Quality Health Environment Safety
RAP – Rig Action Plan

RIH – Run In Hole
SAS – Stand-alone Screens
SOR – statement of Requirements
SPM – side Pocket Mandrel
SSD – Sliding Side Door
TAML – Technology Advanced Multi-laterals
TCP– Tubing Conveyed Perforation
T&D – Torque and Drag
TH – Tubing Hanger
TOC – Top Of Cement
TWC – Thick-Walled cylinder
TVD – True Vertical Depth
WH – Wellhead
XLOT – Extended Leak Off Test
Xmas – Christmas Tree
XT – Christmas Tree

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Chapter 1

Introduction

The oil and gas industry is sometimes deemed a technology averse with not much change in methods of doing work. While there have been massive technology leaps in other oil and gas dependent industries such as automotive and aerospace manufacturing, the oil and gas industry continue to lag behind in methods and execution. Case in point; drilling for hydrocarbons existed before car manufacturing, however the automotive industry has moved from human dependent manufacturing processes to fully autonomous robot driven car manufacturing and assembling plants and currently making autonomous vehicles. On the other hand, the techniques and processes for drilling haven't changed much in the same time period ; with most companies preferring to stick to only tried and tested methods developed years ago. However, in today's era of falling oil prices coupled with rising big data and digitalization, oilfield operating companies have decided to embrace the technology opportunities as they strive to reduce project costs. This has had 3 major drivers

- Reducing rig non-productive time (NPT)
- Reducing well planning time between project conception and execution
- Automation of operations

As far as the oil and gas industry value chain is concerned, the drilling contractors have been at the forefront of implementation and taken advantages of digitalization. This comes as no surprise as partly it's due to pressure from the operating companies to make the drilling execution faster and more efficient in an effort to reduce rig time. Drilling automation and robotics has been ahead of digital well planning mostly driven by cost and injury/ incident reduction. The industry has seen automation on offshore rigs (Eustes *et al.* 2007) e.g robotic pipe handlers on deck with just the driller monitoring and a floorhand to fix anything that requires the occasional human help. With the introduction of wired pipe, it has also allowed the real-time downhole conditions to be monitored in greater volumes with faster speeds compared to the pressure-pulse MWD technologies.

Where are the operating companies (clients) in all of this? While they desire to reduce planning time between project conception and execution, the drilling and completion planning process hasn't changed much. At best, the planning time is usually only reduced by subcontracting the engineering work to specialist companies in an effort to increasing the manhours on the project so that the company employed drilling and completion engineers can focus on other administrative tasks of the project. This strategy can only reduce project costs in the short run but is expensive in the short run due to the increased manhours.

This thesis proposes a new way of well planning by use of a digital framework to reduce well planning time without increasing project manhours. The thesis presents a template and workflows that can be applied to build custom made applications for digitizing the well planning process with a focus on well completions. Another intention of this thesis work is to show the problems with the current well planning process and highlight how the well completion planning process can be moved to a digital planning process. It also highlights the advantages and the benefits of digital well planning in completions with some tangible examples.

1.1 Background

Well planning is the first and most important stage in the well lifecycle management It's the point where the well functionalities are decided, and components selected; expected to withstand stresses from installation to permanent abandonment. Completion design also determines good productivity of the reservoir, or lack of therefore. As such, completion planning gives a chance to mitigate any possible well issues that might arise later in the life of the well before they occur.

Having had the opportunity to work with two oil majors, I've realised that the well planning process is too manual and ususally takes on the following pattern i.e:

- Spreadsheets for calculations
- Simulation with one software
- Drawings and schematics with another
- Repetitive writing of procedures
- Numerous meetings
- Manual approval process for execution
- Rig Action Plans (RAP) printed and handed to the driller/supervisor

Today, a lot of well planning in completions involves several discussion and meetings between the well planning team with other disciplines such as subsurface, reservoir management and material purchase and logistics with back and forth paperwork. Well parameters like perforation depths and reservoir pressure is known through meeting minutes or email requests and engineers spend a lot of time recalculating, re-drawing well architectures for individual wells as well as tending to administrative aspects of the project. This repetitiveness in calculations/tasks by the different teams is one of the main time consumers in the well planning process.

There's certainly a need to digitize and automate these tasks. Well planning can be made faster especially if integrated with experience and lessons learnt from different projects and industry standards. It greatly smoothens and shortens the learning curve. In turn projects can be planned faster and frees up time for engineers to focus on other aspects of the project that justify human intervention such as verifying inputs, completion design outputs and operational follow-up.

In Brechan, Sangesland *et al.* 2019 the concept of digital well planning is introduced from a drilling perspective. From a drilling engineer's view, Well planning is based on trajectory, BHA and section and casing point selection.

From a well completion perspective however, well planning differs from drilling in that the planning is not based on sections drilled but rather a wholistic approach using the already drilled well to satisfy reservoir and production management requirements. This thesis therefore presents a workflow on how to serve this purpose with digital well completion planning.

1.2 Motivation and objectives

The motivation for this thesis stems from my early experience in well completion planning both from the concept development and operations planning perspective. The planning process hasn't changed much and could really benefit from the digitalization wave similar to those in other industries. In this thesis, I hope to achieve the following objectives

1. Design a digital well planning workflow for completions.
2. Use sand control planning as an example to illustrate digital well planning.

1.3 Thesis breakdown

The thesis is structured as below:

- Give a summary of the general well planning process.
- Highlight the shortfalls in the current well planning process.
- Propose a digital well planning process.
- Make workflow and decision trees that can be used to write programs for a digital well completion planning software.
- Showcase application of the flowcharts in conceptual and operations planning sand control.

1.4 Definitions

Digitization: This is the conversion of a physical phenomenon into a language that can be understood and acted upon by a computer. In simple terms, it's the conversion of analogue data into a digital format.

Digitalization: Digitalization is the organization of digitized data into formats, systems and process that make automation possible.

Automation: Application of technology to perform a task without human intervention.

Automation: IBM defines automation as the application of technology, programs, robotics or processes to achieve outcomes with minimal human input.

Well planning: Well planning are the engineering and administrative decisions that lead to construction of a fit for purpose hydrocarbon production or water/gas injection well.

Completions: Completion refers to the installation of equipment and operations in the well to aid optimum communication between the reservoir and the surface facilities.

Chapter 2

Theory

2.1 Highlighting shortfalls in current well completion planning process

2.1.1 The general well completion planning workflow

Well completion planning can be at a concept development or a detailed engineering level. In concept level planning, a general completion is developed that fulfils the project SORs. At this well completion planning stage, different technology is also tested and compared with other options to gauge feasibility. The completion technologies are also matched with the drilling, reservoir management and production goals and constraints to meet an optimum that serves all requirements. Once these have been decided and a simple basis of design (BOD) document generated, then detailed engineering can commence.

The detailed engineering results into a completion architecture that can be fitted to most of the wells in the field is generated with the equipment specifications. The goal is standardization of the well equipment in the entire field for purposes of ease of exchangeability, easy planning, logistics, lead-time reduction and economics. The detailed engineering results into a well completion program for completion execution. See figure 2.1 below.

2.1.2 The current single-well completion planning process

The single well completion is a parent of the detailed engineering and focuses on the individual wells at different reservoir targets and well objectives. While single well plans are sub products of the detailed engineering there is usually similarity between the two.

In the current well planning, the completion engineer also usually works in collaboration with other engineers and stakeholders in the well construction. These are reservoir

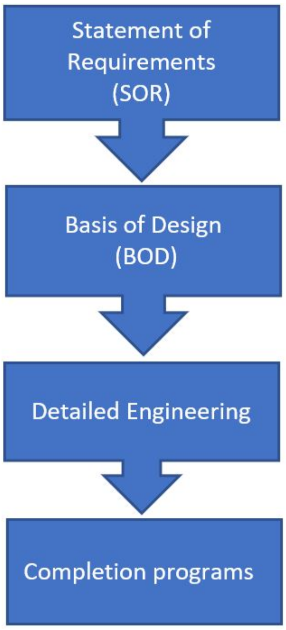

Figure 2.1: Well completion planning stages

engineers, production engineers, geoscientists and of course the drilling engineers. Because of the differences in performance or desires, the well completion process involves back and forth discussions to satisfy every engineer's desires or reach a compromise.

1. **Reservoir and subsurface data collection:**
   The first step is to manually collect data about the reservoir and subsurface from the respective teams. This could be reservoir, pore pressure or lithology and Particle Size Distribution (PSD) data.
2. **Gather requirements:**
   The production requirements to be fulfilled gathered from the production responsible person. This could be the peak production rate through the completion as well as production fluid treatment requirements before the reservoir fluids enter surface facilities. It's from here that demulsification, wax or scaling appearance is determined and required remedies determined.
3. **Well architecture:** Work with drilling and well construction team to design completion architecture. The size of the completion is limited by the casing size and as such close collaboration with the drilling team during well planning is crucial. Additional data like casing Top Of Cement (TOC) and casing shoe depth or wellhead profile is provided by the drilling team.
4. **Liaise with equipment suppliers and logistics team:** The completion engineer liaises with the supplier and the logistics team to ensure that the service/equipment is delivered on location on schedule.
5. **Contracts:**
   Based on the requirements, equipment designed to specification and contracts are awarded for the equipment supplier who can provide the specified services at the best price.
6. **Write a well completion program with procedures**

The well completion program is a detailed execution plan for installing the completion as well as things to look out for as well as the QHSE considerations involved in the execution. It's written in collaboration with other engineers.

7. **Conduct completion well on paper (CWOP):**
   A CWOP is a presentation or meetings with all stakeholder teams prior to execution to ensure that everyone involved is on the same page and understand the objectives and execution plans of the completion.
8. **Monitor execution and performance of completion:**
   The completion installation is monitored, and the performance of the completion is monitored from well start up.
9. **Gather experience:** By manually writing an end-of-well and lessons-learnt report
   The experience in the process is documented by the completion engineer in terms of an EOWR, the lessons learnt, what went wrong and what can be done better in the next completion.

From this, it's clear to see that the completion planning process is very human dependent in moving from one step to another.

Also, in the well engineering team, the different aspects of well planning are usually performed separately. For example, the tubing stress and movement is performed using one software while the lower completion/ pay-zone completion engineering modeling and selection is performed separately by another software. See figure 2.2

It is this separation that cause disconnect errors in the planning, project lagging and loss of several manhours on issues that might not directly be related to the well planning such as meetings and soliciting approval signatures.

2.1.3 Current well completion modeling software situation

The engineering part of the of well completion planning has been dominated by Halliburton's Landmark EDT WellCat module with new entrants such as Oliasoft only emerging recently. These are the preferred tools for tubing design by engineers in the market today while Schlumberger's Petrel finds applications in lower completion for sand control with SandCADE, SandCAT and ICD advisor for valves selection. Prosper and GAP are also usually used for modeling completion production requirements. SubPUMP as a tool for ESP artificial lift sizing and modeling has been around for those who don't have the proprietary product specific softwares. What's clear however is that a completion engineer only has access to most of these modeling tools if the company decides to purchase the completion equipment in question, which greatly impacts the ability to make a more informed decision if they had access to independent modeling tools/software.

This lack of diversity and competition is perhaps why there's been less development in digital well planning. Also, different companies in different regions have different needs and as such might prefer more customized solutions to their engineering needs.

Also, while tools like Landmark EDT have other modules for costs, they are not fully integrated with modules for contract management, or reservoir and subsurface models. This means that separate software has to be used to manage other planning aspects of the project e.g WellView for reporting and the well schematics have to be redrawn, leading to repetition of tasks.

Sand control planning has predominantly been shared between rock mechanics, production engineers, petrophysists and and well completion engineers. The later focusing on the mechanical side of things like torque and drag while running screens, the petrophysists manage the particle size distribution and rock mechanics engineers the expected formation stress changes with production (or injection). Current market software such as Schlumberger's Sand Advisor helps in open-hole sand control recommendation, DIANA for pore pressure reduction prediction and Techlog for core and particle size analysis.

Because the subsurface and well engineering teams have different Key Performance Indicators (KPI) according to which they measure success, such a scenario can make the decision-making process longer due to many meetings and paperwork since the 3 teams don't work/alight together fast. The subsurface teams are more interested in reservoir contact but the well engineering team have other concerns like well drillability, equipment types and safe well construction. However, with digital well planning, all this can be done on the same platform, making decision making faster and less prone to errors due to omission or having more than one person doing the same calculation.

Also. while big companies can afford to have such an array of vendor dependent tools at their disposal, the basic functions can be rolled into one simple software for analysis based on independent standard recommendations to suit more cost individual operator needs. See figure 2.2

2.1.4 Experience transfer

The importance of experience in the oil and gas industry is one that cannot be understated. It reduces planning/operational time and allows for good quality engineering work. The current transfer of experience between experienced engineers and inexperienced ones happened either verbally or by observing the experienced engineers. It's also comes down to the willingness of experienced engineers to share their experiences or the eagerness of the learner to seek the experience. Because of the human dependency of the current experience transfer between teams, learning gaps tend to arise both at the human level and at the overall project level from well to well.

2.2 Key elements digital well completion planning

The planning software of the future should be able to integrate all well planning aspects of a completion engineer in one space. To reduce planning time, the software should be able to perform some tasks automatically and reduce repetitive tasks or those similar to other offset wells in the project.

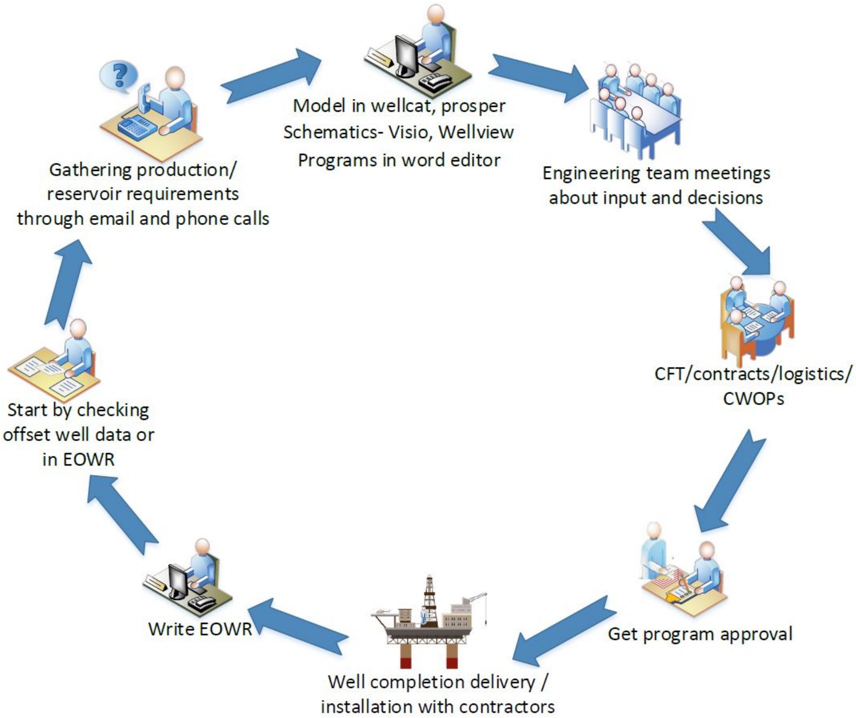

Figure 2.2: Current well planning methodology

In digital well planning, all the engineering functions can be automatically calculated and generated by input into a single well design software accessible by all well engineers, whose only role is to verify that the inputs and outputs are correct. The output should be of a format readable for man and machine, for example a rig automation software to make use of the program directly without much human intervention.

The use of one software allows real time updates to the engineering design without having to manually do calculations and as such saves time and allows visualization of outputs such as schematics and possible failure scenarios which would otherwise remain unseen due to use of different software packages for different elements of the same well. The incorporated lessons learnt from previous projects also help optimize the design for performance and enable quick learning especially for less experienced engineers.

2.2.1 Collaborated planning platform

In the planning phase, well completion requires strong a collaboration between drilling engineers and reservoir, production and subsurface engineers because the completion ultimately affects the production capacity of the well.

In operating companies where these disciplines don't share a common working platform, the planning is impaired by conflicting interests, methodologies and repetition of tasks. For example, the production engineer might wish for a production rate which can't be supported by the proposed tubing size, which could have in term been limited by the casing size installed by the drilling team for well integrity/operations reasons. It sometimes takes hours before the engineer can get feedback about such changes.

All this can be avoided by quickly reaching optimum well designs if the engineers are working the same planning platform. Figure 2.3 shows how collaborated working is from the completion engineer's perspective in a collaborated platform where all engineers work from the same digital space and have access to all information and work done by other team members in real time.

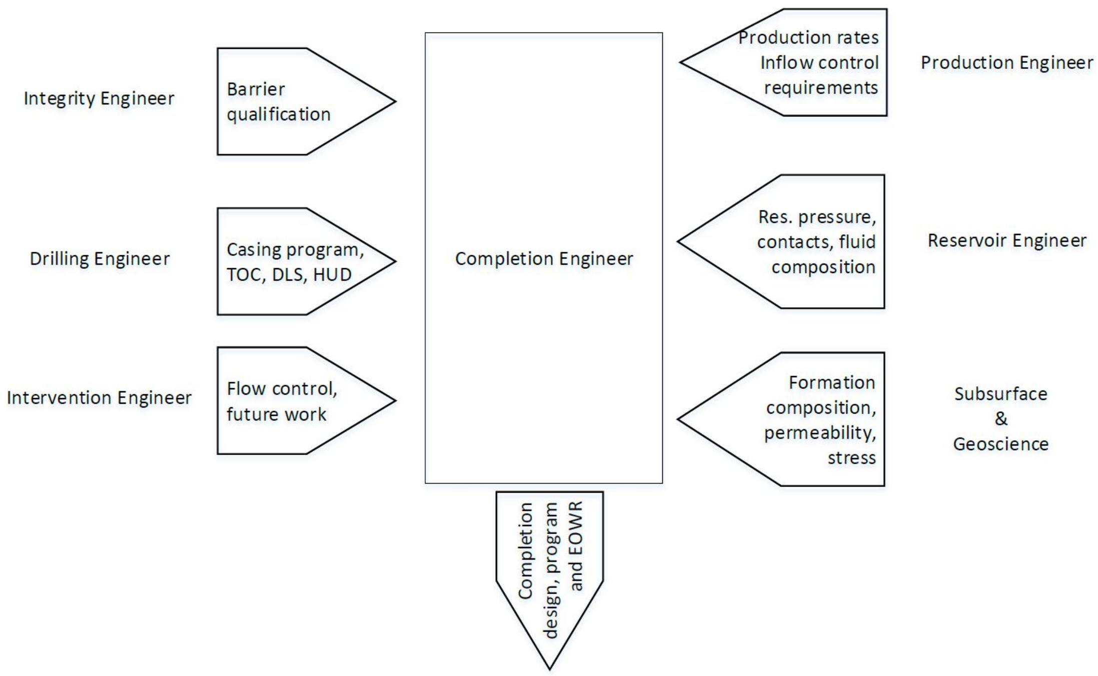

Figure 2.3: Collaborated planning platform from completion engineer's perspective

2.2.2 Fully automated calculations

In most cases, an engineer today uses an engineering handbook where tubular data, fluids and related conversion units are copied and fed into a calculator. This not only consumes time but makes the final calculations prone to errors when copying from handbooks. Importing the handbook data and making all calculations would alleviate this.

Also, while current software has so many functionalities, it requires so much input and work on part of the engineer to ensure that they get the correct output. A fully automated engineering system should be able to self-right if for example a physically impossible input is suggested by the user.

2.2.3 Reasoning behind the software's outputs

Incidentally, the user should also be able to check the calculations and models behind the output for purposes of verification or validity.

Most well planning software today acts like a black-box (figure 2.4) into which the engineer sends well design inputs and he equally gets an output without the thought process behind the output. This builds opportunities for mistakes to pass unnoticed and hinders experience transfer especially for new engineers using the software. Output should be interactive either in text, code or diagrams of different design options, helped by a machine learning database of previous work.

Figure 2.4: Illustration of blackbox system

2.2.4 Open source

The ability of the software to be modeled differently by individual companies is good as it opens it up for innovative and sometimes more efficient ways of running processes compared to the earlier release.

This allows the user to fine-tune the engineering model to meet engineer specific needs. These needs could be a matter of different nature of reservoir, geomechanics forces of equipment for specific operating conditions that would otherwise not be optimal with the default engineering settings/models from traditional supplier specific ecosystems. For example, some of the earlier models on which planning software was built have been found to be prone to error especially in tubular design Brechan, Sangesland, Dale *et al.* 2019. If the software is open-source, new models can be fed into it as they come.

2.3 Benefits of digital well completion planning

The advantages of digital well completion planning are numerous but some of the more obvious ones include:

1. With digital well planning, the planning time could potentially be reduced due to
   - Automation of repetitive tasks

    - Merged working platforms as discussed earlier. Reducing meeting times, which can sometimes involve teams flying from country to country due to the lack of a centralized digital system. This could even be more relevant considering the impact of the current global covid-19 crisis and emergence of other travel restrictions in the future such as wars or visa requirements.
    - Building on previous digital engineering experience

2. Human errors in completion planning can be eliminated reducing well integrity or completion performance issues. See graph in figure 2.5 below from Vignes, Aadnoy *et al.* 2008 for illustration of well integrity issues on the Norwegian Continental Shelf (NCS)

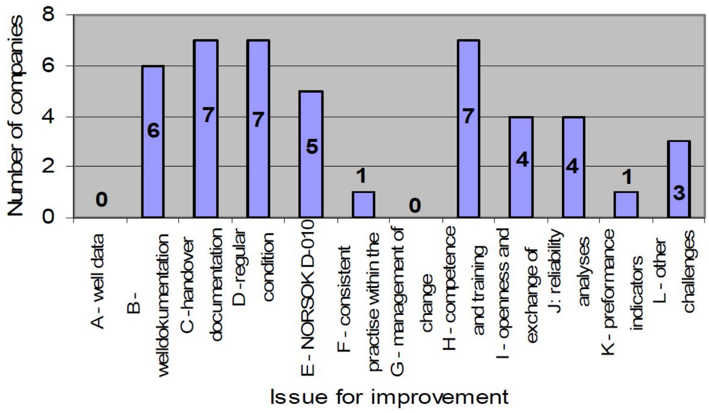

Figure 2.5: Issues for improvement (Vignes, Aadnoy *et al.* 2008)

   From the graph we can see that lack of competence and poor documentation are the highest root causes of well integrity incidents.
3. Digitalization and automation reduces workload on the completion engineers allowing them to focus on other critical roles like performance monitoring or project administration.
4. Minimizes missing information links during handover between the well completion planning team and operations team.
5. Efficient management of change in the well planning process.
6. Digital well planning is more energy efficient due to collaboration and produces less waste since there's no need to print many documents.

Chapter 3

Methodology of digital well planning

The digital well completion planning concept is geared at automating the well completion process and relieving the well completion engineer of most of the repetitive tasks involved in well planning. The figure 3.1 below summarises the concept.

3.1 Digital governing documents

Part of the well completion planning involves referencing governing documents related to operations and this is usually the starting point of the completion planning. These documents can be divided into the following categories

3.1.1 Laws and regulations

These are legally binding and there are legal consequences if not followed. An example is the requirement of the xmas tree to be located below ground level in Uganda.

3.1.2 Standards

Standards can be industry or statutory imposed with no legal obligation and they govern the well completion components, material, functionality and architecture. They are recommendations based on best practice and years of experience about the best and safe ways to design wells or perform well operations. Some common standards are NORSOK D-010 (Standard 2004) for well integrity in drilling and well operations, API and ISO which give equipment specifications.

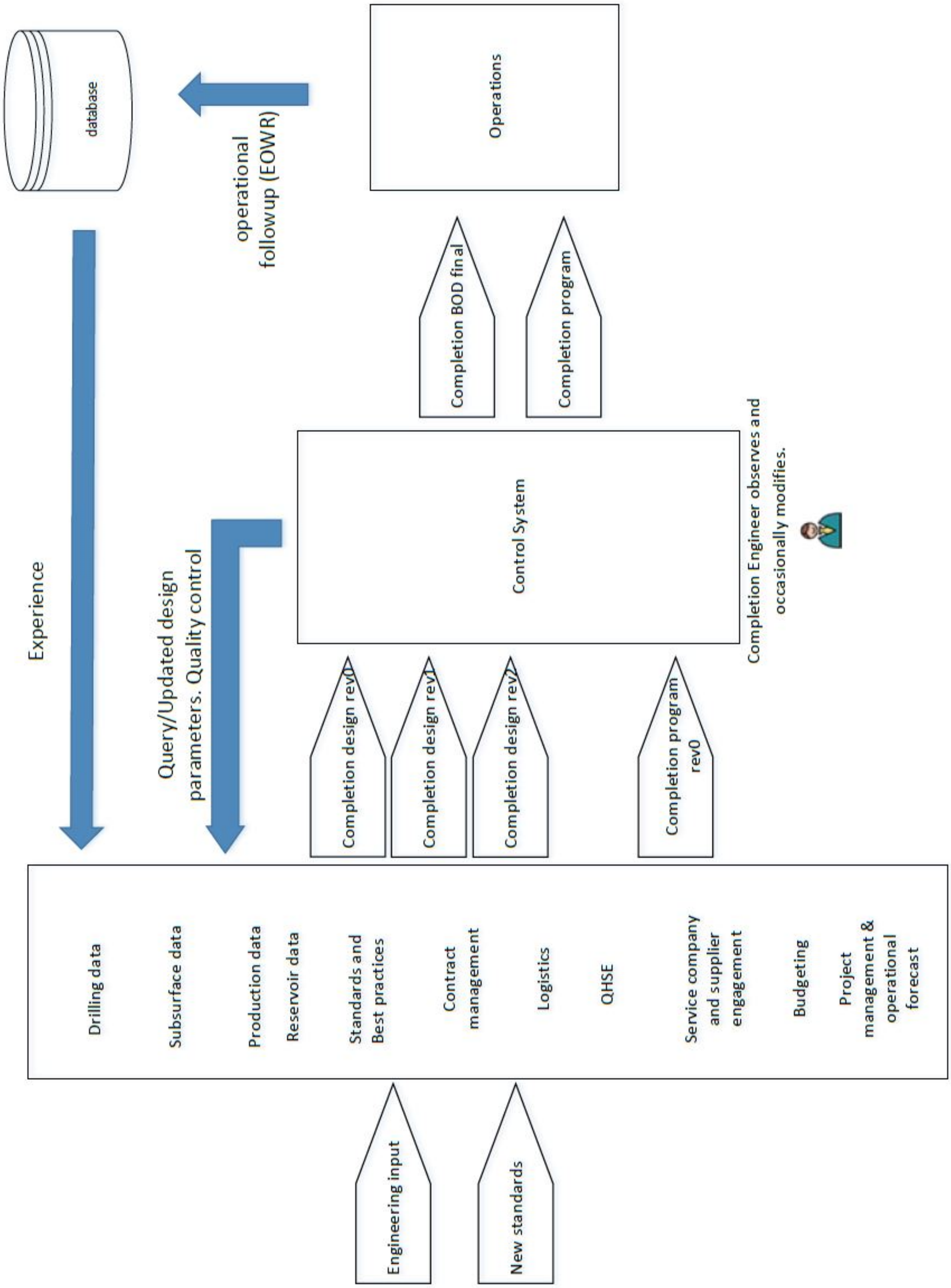

Figure 3.1: Digital completion planning

3.1.3 Internal company documents

And while the standards must be followed in designing the completion, the company can also have internal governing documents to help optimize their work. These could be based on experience or as a way to ensure safety in operations.

The figure 3.2 below shows how these documents are related to each other in terms of flexibility. Usually, the higher up the hierarchy the less flexibility and vice versa.

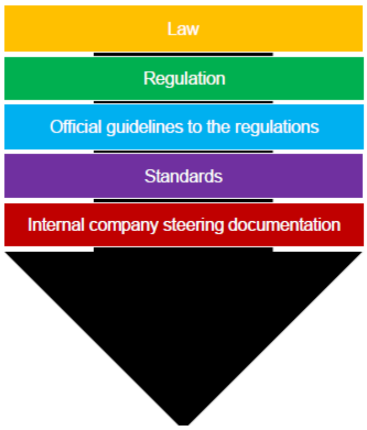

Figure 3.2: Governing documents hierarchy

In digital well completion planning either in design or operation, the standards are usually the starting point. In order for automatic inclusion of these standards or best practices in the completion design, they have to be digitized and into machine understandable language i.e minimum and maximum values, logic maps etc. For example, the NORSOK D-010 (Standard 2004) stipulates completion design safety factors and also has the 2-barrier principle required by requires that there are two barriers in the well at all times and also stipulates tubing design safety factors. This is broken down and interpreted for the different stages of well design, construction and during production in figure 3.3

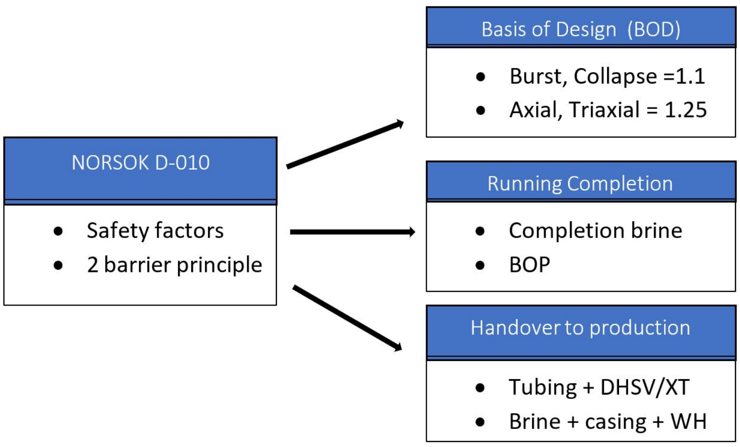

Figure 3.3: Integrating digital standards

This means that the software looks for what the standards and company guidelines (in that order) recommend for the particular completion and will make design decisions based on this. It will apply these as a requirement in the engineering calculations or in the procedures. For example in engineering design the safety factor of 1.3 is acceptable but that of 1 could be rejected (apart from cemented sections of casing). It would then require two barriers as a must in design and program procedures but the third barrier is optional. This is a better option compared to traditionally typing or copy-pasting from old programs. In fact, in Vignes, Aadnoy *et al.* 2008 we see that human errors such as writing mistakes/interpretation errors at the design stage is mentioned as one of the causes of well integrity failures that stem from the well completion planning. This human element can be eliminated if the standards and governing documents are automatically integrated in completion planning.

Another advantage of this is that if there's revision of the standard, it can be automatically updated in the future plans even if the engineer didn't know about this update in the first place.

3.2 Completion Basis of Design and Engineering decision trees

A typical well completion plan usually consists of the equipment selections, functionality, performance and integrity related considerations from lower completion (payzone), middle completion and the upper completion all of which have to be planned based on expected well conditions and stresses.

At the back of the digital planning tool, there are engineering calculations and decisions that determine the final architecture of the completion. Some of the decisions could be internal or as a result of regulations and industry standards; ISO 16530 and NORSOK D010 for example.

In this section the workflow and all requirements for each section of the well completion are included. The workflow can be used as a template for a software to do the analytical calculations to make design decision based on the input. While better results can be obtained by numerical methods approach, the goal of the analytical equations is to give a better understanding of the engineering decisions.

In all these decisions, the fundamentals of a good completion should be incorporated. A good completion should be simple, reliable and safe. The more complex the design, the more failure points created in the system, reducing reliability and provide flexibility of change for future operation or changes on the well. The completion should function as required, performing as expected to maximize production output. It should give maximum return on investment in the well's lifetime, i.e reasonable cost compared to existing technologies while minimizing workover expenditure.

Because a completion is primarily meant to serve reservoir and production requirements while ensuring well integrity, the design takes on a bottom up approach. Every aspect and design of the different elements in a well is subject to different solutions. In completion planning, an early decision map indicating equipment purpose and calculations to be undertaken for each of the completion components as shown in 3.4. This decision map shows some examples of these choices from the lower pay zone completion to the middle and upper completion involving the xmas tree. The decision maps are shown in appendix C

3.2.1 Pay zone Completion

Formation Analysis is carried out either from lab or using other numerical tools to determine the characteristics of the lower completion contacting the reservoir.

Sand control

This takes into consideration the possibility of sand production and the need for sand control/exclusion. If sand production is expected, what strategies or sand control techniques can be applied. For purposes of illustration, a good example of sand control is considered in the digital well planning methodology. See appendix A

Zonal isolation

Zonal isolation is required to prevent pressure communication between zones

- Cased hole or open hole packers
- Bridge plugs
- Cement plugs

Smart completions

Intelligent completions allow control and monitoring of downhole conditions via remotely operated hydraulic/electric control valves.

- Reservoir management requirement to monitor pressure and temperature with sensors.
- Multizone inflow control:

The difference in drawdown across the length of a completion in the reservoir from heel to toe can lead to uneven inflow pressure across the length of the completion especially when the horizontal drain is considerably long. Inflow Control Devices (ICDs) across horizontal the drain can to control inflow pressure. If the difference in flow resistance between toe and heel qL is much less than the average in-flow density q_L. Pressure loss Δp_c along the completion must be balanced by an equal pressure drop across the ICD.

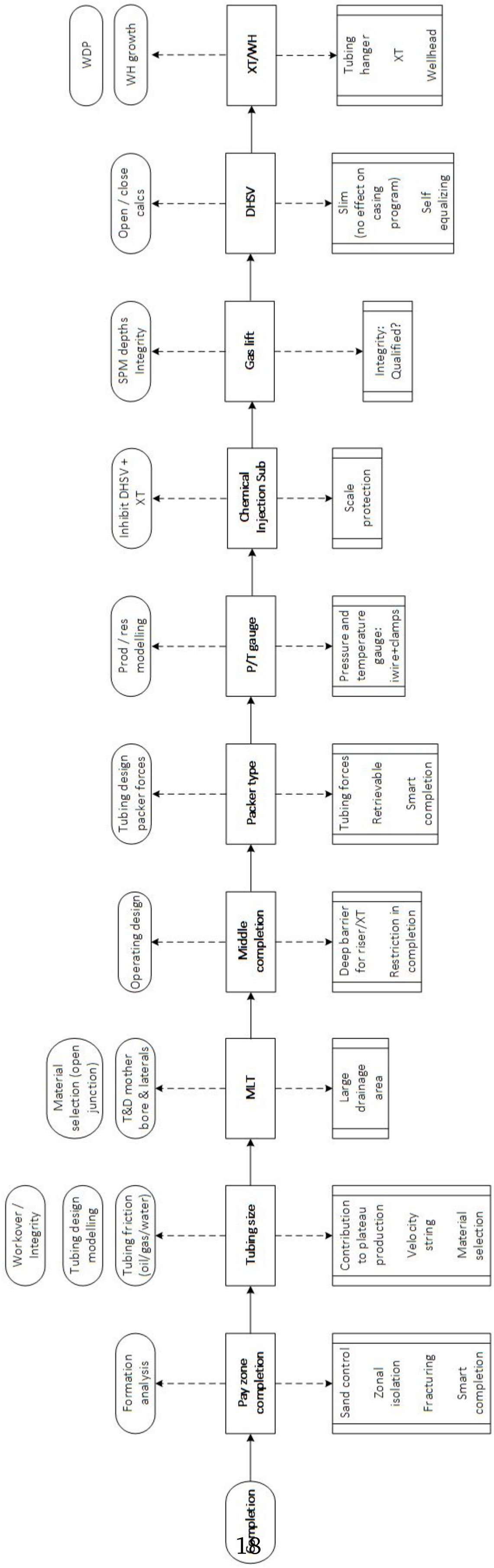

Figure 3.4: Typical NCS completion BOD decision map

The nozzle ICD flow area is given by equation 3.1

$$A_c = (L_c/n_c x^{1.5})(3\pi^2 d^5/16f)^{0.5} \tag{3.1}$$

Where d is the pipe diameter, f is the friction factor, x the length along the pipe in the flow direction, L_c is the length between ICDs and n_c the number of nozzles on the ICD.

Hydraulic fracturing

Hydraulic fracturing is meant improve reservoir productivity by by-passing the near well bore damage and increasing permeability of otherwise low permeability reservoir rocks such as chalks and shales.

If an extended leak off test (XLOT) (figure 3.5) is performed, we can determine the value of the fracture pressures and corresponding principal stresses of the formation.

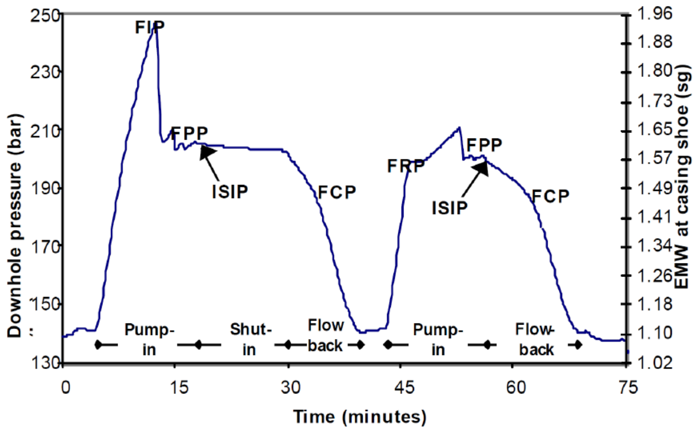

Figure 3.5: Extended leak-off test

Where FIP - Fracture initiation pressure, FPP - Fracture propagation pressure, FCP - Fracture closure pressure, ISIP - Instantaneous shut-in pressure and FRP - Fracture re-opening pressure. For the case of an impermeable borehole wall of a vertical well with pore pressure p_f, FIP can also be obtained from equation 3.2

$$P_{frac/FIP} = 3\sigma_h + \sigma_H + p_f + T_0 \quad \| \, \sigma_v \tag{3.2}$$

The minimum horizontal stress σ_h is the fracture closure pressure and can obtained from the mini-frac test, while vertical stress σ_v can also obtained from density logs. Initial tensile rock strength T_0 is obtained from core measurements or sonic logs. The maximum horizontal stress σ_H is obtained from the fracture reopening pressure at which point $T_0 = 0$ in equation 3.2. The fracture closure pressure is a direct measurement of σ_h

Completion fluid selection

The completion fluid used has to take into the following factors

- Drill/in fluid requirements to minimize reservoir damage and invasion
- Brine density and quality (cleanliness)
- Corrosion inhibited
- Resistance to degradation with temperature

3.2.2 Tubing size

Plateau production requirements

Let Q_L be the desired plateau production at the wellhead per unit time t, flowing through tubing of length L and internal diameter ID. The ID can be expressed as

$$ID = 2(Q_L t/L\pi)^{0.5} \tag{3.3}$$

Erosion velocity

The velocity v_c in ft/s at which fluid flow starts causing erosion inside the tubing. This is determined from expression 3.4

$$v_c = C/\rho_m^{0.5}) \tag{3.4}$$

Where C is an empirical constant for the tubing material e.g 620 for carbon steel or 890 for 13Cr and ρ_m is the fluid density (lb/ft3).

Material selection

Choice of material for tubing and other completion components is important.

- Material yield strength through modeling i.e casing and tubing load safety factors 1.1, 1.1, 1.25 ,1.25 for burst, collapse axial and triaxial respectively for all load cases expected in the well's lifetime from installation, production/injection to POOH
- Temperature effects from initial conditions i.e for production and injection
- Corrosion from produced fluids depends on dissolved CO_2 and H_2S corrosion will be considered. Generally if CO_2 and H_2S partial pressure < 10 low alloy carbon steel is used for the tubing,otherwise Chromium or nickel alloy steel for HPHT wells.

3.2.3 Multi-lateral completions

A multi-lateral well is one with more than one bore all connected to the main bore. The drilling and completion through the primary bore allowing cost and time savings from drilling separate conventional bores. The Technology Advancement of Multilaterals (TAML) system is used to classify the different types of multilateral wells basing on the number of multilaterals and the hardware used

- Level 1: Open and unsupported junction.
- Level 2: Main bore cased and cemented, lateral open hole.
- Level 3: Main bore cased and cemented, lateral cased, but not cemented.
- Level 4: Main bore and lateral both cased and cemented.
- Level 5: Pressure integrity at the junction achieved by completion equipment.
- Level 6: Pressure integrity at the junction achieved by casing.

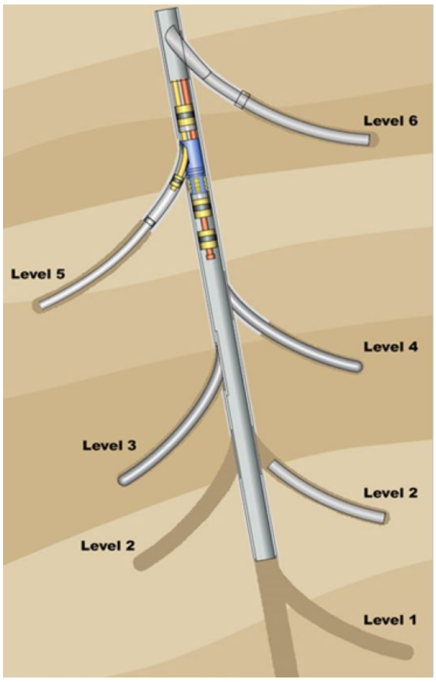

Figure 3.6: TAML categories

The major need for multilateral wells is to increase drainage area without the need for a new wellbore. They key issues of design in multilateral technology are:

- Drainage area
- Open junction material selection
- Torque and drag modeling for mother bore and laterals

3.2.4 Middle Completion

The middle completion is installed between the lower completion and the upper completion. This completion allows installation of a barrier for isolating the lower completion without the problems of losses associated with pulling deep set plugs in highly permeable reservoirs. The middle completion barrier conforms with the 2 barrier requirements by

NORSOK D10 well integrity standards (barrier plug and brine) when the XT is no longer a barrier. Such a completion is shown in figure 3.7.

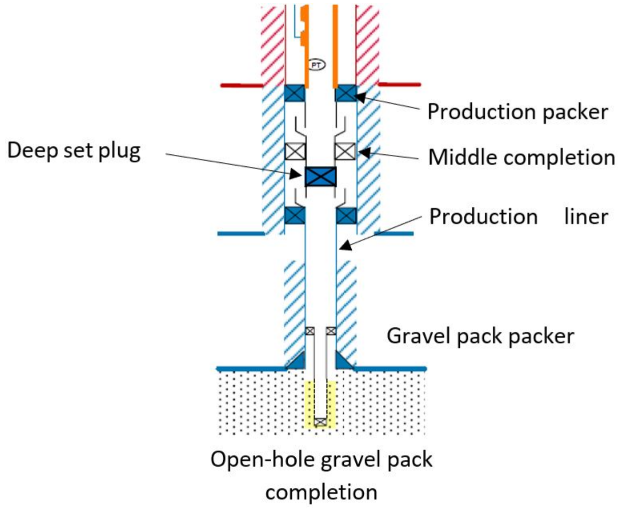

Figure 3.7: Middle Completion

3.2.5 Packer type

Packers allow isolation of the production fluids from the casing-tubing annulus. They also allow zonal isolation. In that respect they can be open-hole or cased-hole. They can also be hydraulic or hydrostatic set and permanent or retrievable.

Tubing design packer forces

During normal operation:

- A packer transmits axial forces from the tubing and tailpipe into the casing via anchors (tubing to packer loads).
- Differential pressure across the packer elements from gas lift injection or the reservoir.

Setting packer: When the setting mechanism is activated, the packer locks in the axial loads in the tubing at the packer depth.

Unsetting packer: To unset the packer, the string is lifted and an extra overpull for unlocking the setting mechanism (release force) is factored in addition to the string pickup weight. The packer can have a tailpipe onto which gauges, and sensors are fixed to monitor downhole well condition and the packer body should have ports for passage of control lines for downhole valves and other monitoring tools.

Pressure and Temperature Gauge

Downhole pressure and temperature measurements are critical in facets such as Production and reservoir modeling, completion integrity and operations, in-flow performance and general reservoir management. Downhole electric gauges with electric line to surface, clamped at every tubing connection to allow top side pressure and temperature readout.

- Ported packer, tubing hanger, christmas tree to allow control line connection
- Pressure ratings of ports not to be exceeded if they don't match the wellhead pressure

3.2.6 Chemical injection

Scale build up can reduce tubing ID which can increase friction pressure drop in the tubing. It could also hamper the closure of the DHSV if it builds up on the flapper, consequently causing leaks when the DHSV is cycled to close position. Carbonates such as calcium carbonate ($CaCO_3$) and sulphates like calcium sulphate ($CaSO_4$) and barium sulphate ($CaSO_4$) are the typical scales that build up in the completion

Scale prediction

Generally, if there's CO_2 partial pressure reduction and high temperatures, this creates conditions for carbonates to precipitate from solution to establish ionic equilibrium in the fluid. The supersaturation ratio (SR) gives the prediction for scale formation

$$SR = IP/K_{sp} = Ca^{2+}HCO_3^-/K_{sp} \tag{3.5}$$

Where IP is ion product of carbonate and bicarbonate concentrations in solution the and K_{sp} is the solubility product constant.

3.2.7 Gas lift

Gas lift works by injecting gas via the A-annulus into the well tubing flow stream to reduce the hydrostatic pressure in the tubing. The injection valves are situated in the side pocket mandrels (SPM) in the tubing and consequently the deeper the SPM, the more hydrostatic pressure can be reduced in the tubing. Popular in the presence of high quantities of gas for its reliability and deployment simplicity. If SR < 1 solution is undersaturated and scaling not expected. However if SR 1 solution is supersaturated and scaling expected. This justifies the need for scale inhibitor injection.

Unloading the well

At start up, pressure is required to overcome the tubing hydrostatic pressure and replace this with the gas in the annulus. This pressure is determined by the depth of the SPM and at that depth kick-off pressure will reach its maximum, dropping as the gas starts to enter the tubing. This maximum injection kick-off pressure is given by

$$P_{inj} = hg(\rho_{brine} - \rho_g) \tag{3.6}$$

Where h is the TVD of the lowest SPM orifice in the completion ρ_{brine} the tubing fluid density (brine) and ρg the density of the injected gas.

Integrity

Since it's desirable to have the SPM as low as possible to reduce the tubing hydrostatic pressure, this will create high kick-off pressure in the casing at very high depths. To ensure casing integrity, the kick-off pressure should be less than the casing burst pressure P_{csg} for casing integrity, $P_{inj} < P_{csg}$. Installation of unloading valves above depth h can reduce the required kick-off pressure P_{inj} by unloading the tubing in intervals

3.2.8 Downhole Safety Valve

A downhole safety valve is a fail-safe device that shuts in the well in case of an emergency. It constitutes a flapper valve kept open by surface hydraulic pressure via a control line. While dual control line valves exist, in this thesis only the single control line valve is considered.

DHSV setting depth and opening pressure

The DHSV has a maximum setting depth below which it won't close due to excessive hydrostatic pressure in the control line keeping it open. This depth can be determined from the equation.

$$D_{max} = (P_{vc} - P_{mc})/\rho_{cf} \tag{3.7}$$

Where D_{max} is the maximum fail close setting depth, P_{vc} is the valve closing pressure (spring dependent), P_{mc} is the safety margin (manufacturer ρ_{cf} is the density of the control or annulus fluid depending on which density is greater. The required pressure to open the valve at surface is given as

$$P_{surface} = P_{vo} + P_t + P_{mo} - \rho_{cf} D_{set} \tag{3.8}$$

Where P_{vo} is the spring opening force (psi), P_t is the maximum expected tubing pressure (psia), P_{mo} is the manufacturer given opening margin with piston friction accounted for, ρ_{cf} the control fluid density (psi/ft) and D_{set} is the DHSV setting depth (ft).

3.2.9 Christmas Tree and Wellhead system

The christmas tree and wellhead system is where the completion terminates at surface for dry wells or the seabed for subsea completions.

Christmas Tree

The christmas tree allows control of flow from the well to the production flow line via the flow wing valve. The master valve on the XT can be used to shut in the well. It also allows access to the well via the swab valve in case of well intervention.

Vertical xmas tree: The tubing hanger is suspended in the wellhead. This implies that the tubing hanger is run into the well along with the tubing and then the xmas tree is installed onto the wellhead. The master valves in a vertical are also in line with the tubing in a vertical position.

Horizontal xmas tree: In this type of XT, the tubing hanger is suspended in the xmas tree. This implies that the xmas tree is installed before running the tubing hanger and tubing.

- Vertical XT eliminates the need for running tree plugs prior to removing the BOP during installation, an operation that has to be performed with horizontal trees and is very weather dependent.
- Horizontal XT allow a wider bore compared to vertical trees.
- Vertical XT finds application where frequent tubing replacement or workover operations are expected since closing and opening valves is easier than running plugs.

Tubing hanger

The tubing hanger suspends the weight of the tubing into the wellhead (or XT for horizontal XT). It is held down in the spool by lockdown bolts to mitigate growth from tubing thermal expansion. The tubing hanger also has a profile for running a barrier plug or back pressure valve to isolate the well in operations such as pressure testing the xmas tree.

- Dual TH neck seals to allow testing the TH from the xmas tree without pressurizing casing
- Tubing hanger should allow control lines ports

Wellhead

The wellhead provides spools provides termination for casing strings as it's the suspension point of the casing in the previous casing strings. In effect it transfers casing weight onto the surface via the conductor pipe and seals off the casing annuli.

- Pressure classification: The wellhead pressure rating should be higher than the maximum expected operating pressure in the well's lifetime.
- Tensile strength to support weight of casings.
- Corrosion resistance based on expected partial pressure
- Wellhead growth: this is a phenomenon in which free uncemented sections of casing undergo axial elongation from thermal stress due to increase in temperature when the well is in production.

$$\Delta\sigma = \alpha E \Delta T \tag{3.9}$$

$$\Delta L = \alpha L \Delta T \tag{3.10}$$

Where $\Delta\sigma$ is the incremental thermal stress $1/^{o}C$, E is Young's modulus of the casing material ΔL is the change in length, α is the linear expansion coefficient of the casing material, ΔT the average temperature change across a casing ^{o}C of length L tied back to the wellhead, m.

3.3 Digital Contracts

To ensure that specific work doesn't fall through the cracks, contracts are assigned for specific services and supply of equipment necessary for well completion installation. In well operations contracts are of the following types.

- Service specific contract: Every service is managed by one contract awarded to A provider deemed to be most qualified for the task both technically and financially.
- Lumpsum contracts: The whole package for all aspects of the completion is awarded to one contractor for easy management.
- Alliances: This type of contracts has fluidity where the contractors work together with the operator as one team generating synergies. It's project performance compensation based

In a digital well completion planning, the contracts are digitized and reduce to the level of equipment, personnel and specific service

3.3.1 Scope of Work/services

During an operation planning, every activity is mapped to a service backed by a contract. It's therefore important that the anticipated service/work is backed by a contract clearly specifying the work to the detail. The goal is to reduce ambiguity and confusion about responsibilities and obligations.

3.3.2 Equipment and personnel

The execution of the services to be contracted is enabled by equipment related to that service. This can range from handling equipment of the tool (which the rig may not have) to the personnel specialized in running the equipment. See figure 3.8 below

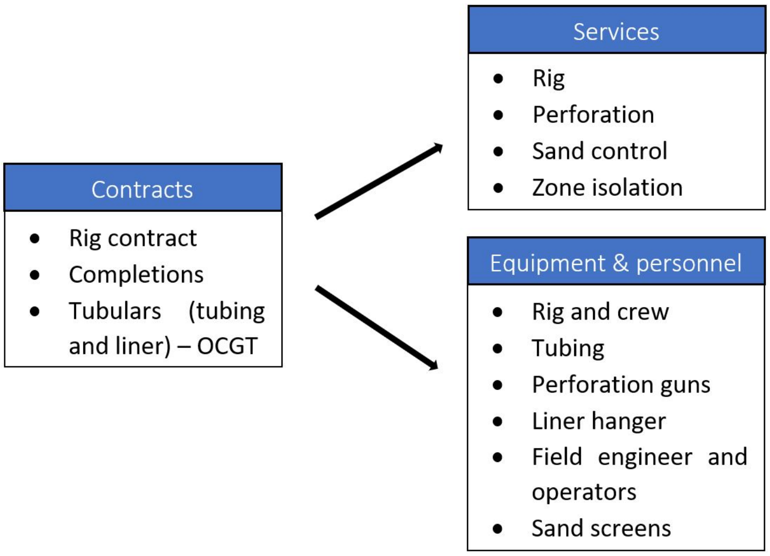

Figure 3.8: Operations equipment and personnel

3.3.3 Digital cost and AFE generation

An important aspect of the well completion planning process are the costs. These costs can be one-time equipment purchases or as a result of contract obligations between the planning company and its suppliers/service providers. With experience from previous contracts in the database, automated Authorization for Expenditure AFE generation for future well completion projects becomes easy since they already have a list of equipment and services in the digital contract.

It becomes easy to map the contract items and their cost according to the contracts to which they belong. From this, the rental rates and durations with their related costs can be used to generate the cost reports of the work done without manually entering this data on a spreadsheet making it susceptible to error.

3.3.4 Digital completion programs and Rig Action Plans (RAP)

Writing well completion programs is one of the most repetitive tasks performed by well completion engineers. Since in most cases, the well architectures in a given field tend to be the same. The only things that typically change between wells are depths, fluid volumes and a few specialized.

Ideally, these procedures could be automatically generated with great input from equipment suppliers to automatically generate installation details of said equipment. The role of the completion engineer would be to verify that the generated completion program is accurate.

Proposed completion schematics

The well completion and BHA schematics can be generated automatically based on depth input well data, offset wells (experience) and the existing completion contract and equipment modules. This eliminates the need of having to draw them using other tools and saves time.

The design standards such as barrier requirements are also taken into consideration to generate compliant barrier schematics both in installation at handover.

Digital programs and procedures

Today after a lot of experience in well operations the industry has developed standard procedures for most well completion activities. Take a look at the tubing conveyed perforation procedure for example

1. Change rig handling equipment to gun size.
2. Run in Hole guns on drill pipe to setting depth
3. Perform GR/CCL+CBL log on wireline
4. Correlate gun depth
5. Set the packer
6. Detonate firing head with drop bar or pressure to shear pins
7. Confirm guns fired and perform flow check
8. Unset packer with overpull
9. POOH and lay down spent guns
10. Prepare to run lower completion

This procedure is the generic, i.e best practice procedure for a perforation job in a well completion program. Instead of copy pasting this same procedure for every new program, it can be written just once in a software that can automatically reproduce it and this is the basis of the digital well completion program generation in digital well planning. This is illustrated in figure 3.9 below.

The specific details such as volumes, packer pick up weights can be calculated automatically in the engineering module discussed in section 4.9.

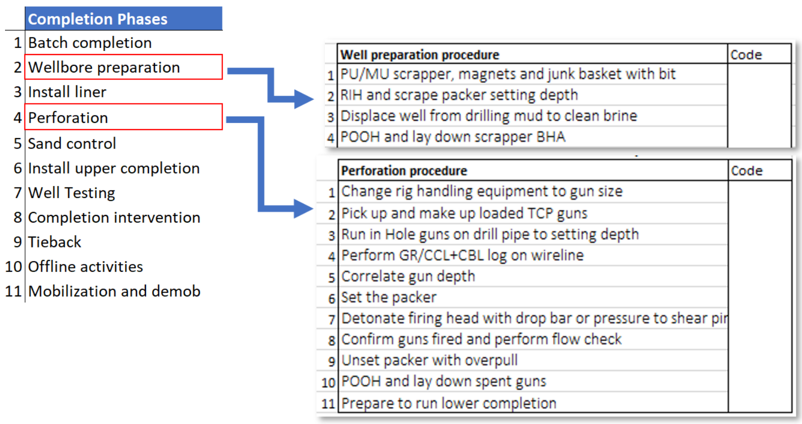

Figure 3.9: Illustration of digital program methodology

Operational Time and schedule management

In the offshore environment where rig rates can reach over $500000 per day schedule management becomes one of the key focuses in completion planning.

Automatic generation of planned time schedule basing on experience from similar tasks in previous projects becomes a capability in a digital environment. The schedule can be monitored, managed and fine-tuned with different options in installation procedures; ever choosing the procedure which will allow the faster but safe installation of completion. It also allows easier detection of time thieves in well completion operations.

The capabilities are also limitless if incorporated with digital rigs, because of human factors like fatigue and lack of concentration, installation times for the same equipment can vary depending on who's on shift that day. However, with automated rigs, you can achieve the same installation time minimizing lag in the installation timeline. This also allows easy quantification of costs involved in renting well completion services.

3.3.5 Digital experience

As highlighted in subsection 2.1.4, experience transfer in the current well planning process is by word of mouth or written documents by more experienced engineers. And while this experience has been made into standards and best practice, it's still in the form of written documents. However in a digital planning environment where these have been digitized, experience transfer can happen in the completion design and operations planning with minimal human involvement.

Digital experience in well completion design and operations

As is the case in most well operations, a lot of data is collected to monitor downhole conditions from ECD to reservoir pressure, especially with the introduction of wired pipe. When operations are going smoothly, it's stored on a hard drive and no one knows what to do with it after. Interestingly, it remains the humans, who are responsible for monitoring this data in real-time and interrupting the system when they notice abnormal condition. This information is sometimes too much for a human to process. A drillers console with 50 gauges or 100 lines of well status trends doesn't translate better drilling but rather confusion or ignoring of the less used outputs.

The same challenge is affecting the "lessons-learnt" databases of many operating companies today. The information collected has to be manually sifted through, read and then implemented in the next plan either in projects or on a well by well basis. There has got to be a way for the computer system to detect and categorize this data into meaningful reports that it automatically indexes for easy reference. See figure 3.10.

As noted in subsection 3.1 the initial well completion design is usually based on existing governing documents such as standards. However, the standards themselves are a result of past experiences from which we learnt what works and what doesn't. The initial well completion output i.e the first design iteration can be automatically generated from standards, previous well designs with similar conditions, with the incorporation of lessons learned and nest practice documents. These best practice documents e.g standards and company governing documents (NORSOK D-010) can be stored and translated into the machine decision making during well completion design. Since computers can't easily understand statements, alpha numeric codes can be used to identify an event or task. For example, continuing from the generic procedure in 3.3.4 the corresponding daily completion report from operations following the completion program are shown in figure 3.10 below. In this particular case, the perforation guns got stuck after perfor-

Old report

	Daily Completion Report DCR##04	Code	Duration/hrs	Category
1	RIH 4-1/2" guns on 3-1/2" drill pipe	PET	6	PT
2	Set retrievable packer and pressure test	RPI	0.75	PT
3	Circulate well for 500psi underbalance	PCD	1	PT
4	Fire guns to perforate 7" liner	PET	0.25	PT
5	Unset retrievable packer	PET	0.1	PT
6	Prepare to POOH. Guns stuck - jarring	NGI	1	NPT
7	Work string to free guns. String snapped, POOH	SWF	8	NPT
8	RIH fishing equipment and tag fish at 1200m	REP	10	NPT
9	Fish pipe and gunsLD fish and spent guns	REP	6	NPT

New well program/plan

	Activity	Code	Procedure	Lessons learnt
1	Preparing the well	PR	DCR##05	N/A
2	Perforation	PET	DCR##05	LLR##04
3	Scraper run	SCR	DCR##05	N/A
4	Run lower completion	IC	DCR##05	N/A

	Lessons learnt report LLR##04	Code
a	Circulatewell for less tha 100psi underbalance or in overbalance	PET
b	Include safety joing in BHA	PET
c	Use auto- gun release guns	PET

Figure 3.10: Post operations digital experience

ation due to excessive underbalance that swabbed sand from the perforations coming into the well and covering the guns. The sand and debris caused the guns to be stuck in the well. The lesson learnt for future perforation activities are:

1. Minimize the underbalance to reduce the produced sand
2. Include safety joint in the TCP BHA

3. Use auto-release guns in next TCP design

If a new completion program is produced, the system is able to automatically incorporate this new knowledge by relating the perforation code PET detected in the new program activity with the PET code in the old report.

The parameters related to this event e.g brine density, depth, string weight, well bore geometry etc are also automatically communicated and compared for digital interpretation in real time; see figure 3.11 below.

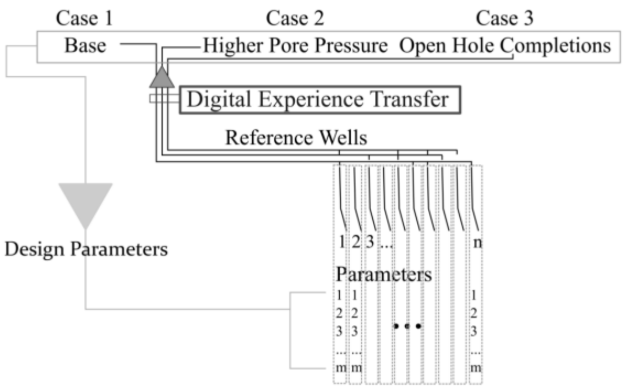

Figure 3.11: Real-time digital experience (Tvedt *et al.* 2017)

Digital experience in well completion reliability and failure prediction

As noted by Vignes, Aadnoy *et al.* 2008, well integrity issues for wells in the Norwegian Continental shelf, the completion items failures such as tubing, ASV, DHSV and packer failure contributed to majority of well integrity issues found in wells.

The goal of completion planning is to ensure that the equipment works efficiently and that well integrity failures and workovers are minimized as much as possible. From an economic point of view reducing maintenance expenditure while maximizing return on investment from the deployed completion technology. With that in mind, the ability to model and predict the failure of the completion and its components should be incorporated in the digital planning design.

As an example from the above well completion schematic 3.12 from Ajimoko *et al.* 2016, the well failure tree is produced as shown below where leakage to the surrounding area of the is the top event and the basic events are DHSV failure to close, DHSV leakage in closed position and tubing to annulus communication. From this failure analysis, a fault tree such as the one in figure 3.13 is used to quantify the failure probability

This can either be from reliability and mean time to failure (MTTF) databases or from lessons learnt from experiences where similar or relevant completion technology has been deployed before. The failure probability of the system is the failure probability

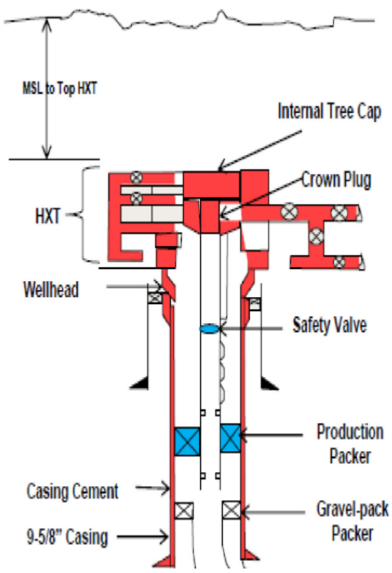

Figure 3.12: Barrier schematic for production well (Ajimoko *et al.* 2016)

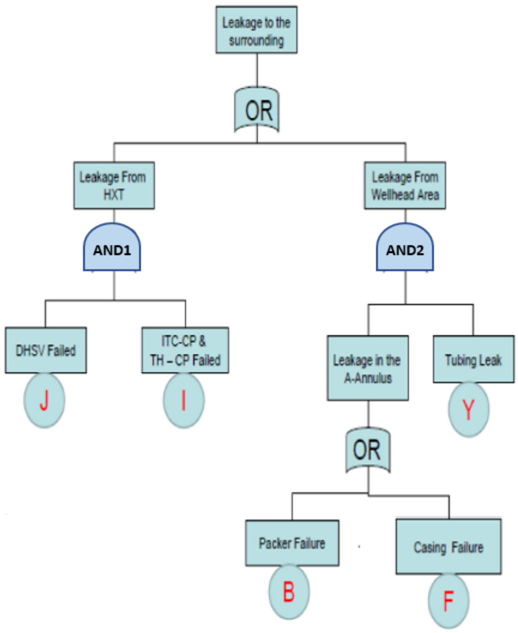

Figure 3.13: Completion fault tree analysis prior to production

of the failure components along the leak path. The same can be done for individual components. See equation 3.11

$$Failure probability = Reliability/MTTF \tag{3.11}$$

Digital experience in Risk and Impact assessment

Risk assessment is an important aspect in the well completion planning process. While it's usually possible for the engineer to think about potential risks facing the project or the completion design and installation, it is impossible to quantify the impact of the risks without experience. Experience stored digitally and by use of certain metrics can be used in attaching related consequences of failure as well as categorizing them.

The input is usually from offset wells or projects with similar subsurface properties and technology. For the example given in table 3.1 below from King *et al.* 2003 shows general reliability of sand control completions.

Table 3.1: Reliability of sand control completion types reproduced from King *et al.* 2003

Completion type	Number of wells	Total well years	Design failure/%	Application failure/%	Infant failure/%	Production failure/%
Injectors	24	62	0.0	12.5	0.0	0.064
Screenless Fracs	7	44	0.0	0.0	0.0	0.046
Perfed casing	66	306	0.0	1.5	0.0	0.085
SAS	183	783	0.6	0.0	0.6	0.056
Expandables	194	255	1.0	3.0	1.0	0.016
Cased hole GP	369	1514	0.0	2.2	0.8	0.011
Open hole GP	175	507	0.0	9.7	0.67	0.020
HRWP	187	544	0.0	0.5	0.53	0.009
Frac pack	844	3369	1.69	2.4	0.24	0.004
Total	2049	7384				

As far as the sand control completion types considered in this thesis goes, the risk corresponding assessment results are as shown in table 3.2.

Table 3.2: Sand control based on production failure probability experience

Type of sand control	Improbable	Remote	Occasional	Probable	Frequent
SAS					X
Expandables			X		
Cased hole GP		X			
Open hole GP				X	
HRWP		X			
Frac pack	X				

Mitigation measures can be suggested based on output from the risk assessment. Further examples of risk quantification with advanced models using data from offset wells can be found in Mohan *et al.* 2020.

Digital experience in automated report generation

The planned and actual results of the well completion can be quantified and automatically generated in the end of well report (EOWR) and lessons learnt. Possible input into the automatically generated EOWR is from the events log. Incidentally other reports such as planned vs actual, NPT, cost reports and schedule are generated in relation to other modules of the software such as the contract module and the schedule management module. This can all be possible if all facets of the planning are already digitized and on a merged planning platform. It eliminates the need to manually write the reports.

3.4 Control unit

At the heart of any digital system, there's always a control unit taking input, processing and outputing results. In digital well planning, the roles of the control unit can be split into two:

3.4.1 Logic and Engineering decisions

An important aspect of the digital planning in well completion are the back-end calculations that determine engineering decisions/output. Another one is the logic that decides what to implement and when

3.4.2 Quality control

To ensure accurate output, the engineering though valid should be within the design envelope for the specific well e.g 6000psi pressure rating automatically converts to 10000psi in equipment selection. The control unit is required to make these checks automatically. Figure 3.14 shows the a flowchart for how the quality control would work.

Engineering

For the procedures to be valid, they have to be backed by equally correct engineering calculations. For every event, the related engineering evaluations to be carried out are evaluated until they are valid. The status of the engineering can be verified at each level and once all the engineering involved is valid, the green light is given for the execution. For example,

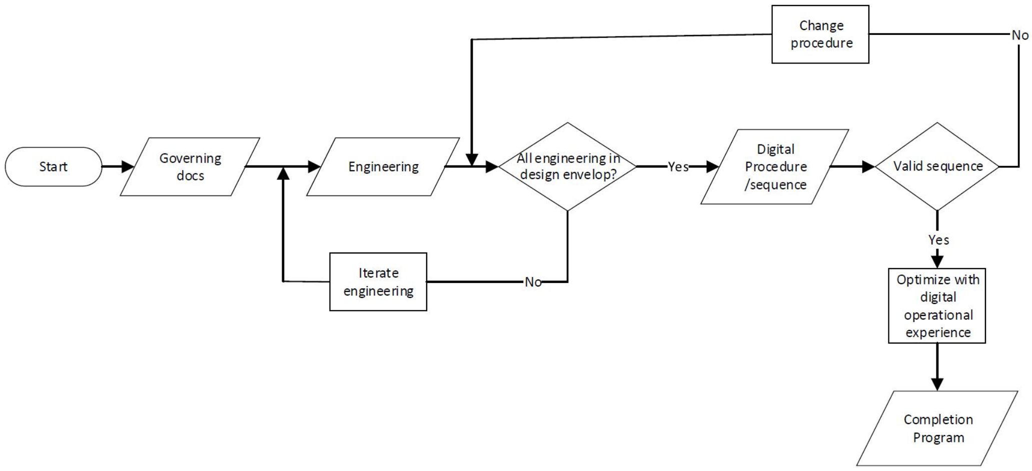

Figure 3.14: Automated quality control

- Safety factor shall not be less than 1
- The drag can't be higher than the rig's handling capacity.

Schematics and BHAs

The BHA should also be validated. As an example, the lowest nipple ID < higher nipple IDs. If a completion schematic is selected that has ID specifications contrary to this, the system can automatically reject it.

Completion program events

During well completion operations, a sequence of events is usually followed and one cannot happen before another. For example, circulating the well cannot happen before BOP pipe rams are closed or before a string is RIH. This should also be reflected in the completion program logic and the control system would make such input invalid.

Final program authorization

Because there's no paperwork involved, the manager, engineering lead, superintendent etc in the company hierarchy can also digitally sign off on the programs without the need to sign and scan the signatures. This makes the work process faster especially where the wells team is not collocated (Mohan *et al.* 2020). It's mostly at this point that the human involvement discussed in section 3.6 would be required as the final quality control measure.

3.5 Linking digital well planning with rig automation

As discussed earlier, the goal of most companies is to minimize the people on the rigs and platforms to reduce incidents and injury to humans. Rig automation and digital well planning should go hand in hand. Today we see digital rig action plans delivered straight to the drillers console in figure 3.15 as opposed to the printing the instructions on a piece of paper by the tool pusher or completion engineer.

Figure 3.15: Driller using digital RAP (from Isbell *et al.* 2021)

However, for the rigs to require less input from the driller, the rig should directly read detailed instructions from the program and execute as required

3.5.1 Automation / process environment

The procedures are based on the engineering decision maps developed and discussed in section 4.6. They follow the best practice i.e the tried and tested way to execute something and the digital completion procedures could in effect be fed into an automated rig and for automated execution.

However, in the real-world things are not always straight forward and conditions might occur dictating a change in the execution procedure. This could be due to difference in the rig set up, weather, borehole conditions or personnel. The system therefore should allow for anticipation of these deviations from the best practice and provides alternative procedures before continuing execution of the best practice procedures.

The process environment, a concept from Brechan, Sangesland *et al.* 2019, describes what equipment on the rig is needed to carry out a specific task and how this relates to digital planning. In a nutshell, what this implies is that it would be possible for the well planning software to give instructions/call out rig automation modules to carry out these tasks. The process environment is thus rig/vessel specific. For example a rig could use drill pipe to run a tree while an intervention vessel would use a wire.

3.6 Human involvement in digital well planning

Human errors contribute to a great deal of well integrity incidents not only at planning level but during execution. The goal of digital planning therefore is to reduce human involvement and only be introduced in cases where there's dispensation from the original work plan.

3.6.1 Completion engineer's role in digital well planning

Today's completion engineer's well planning roles can be divided into two.

- Engineering design
- Administrative work involved around well planning e.g budgeting, contracts management, equipment supplier engagement logistics.

It also comes as no surprise that the administrative work of the completion engineer consumes majority of their project time.

However, with digitalization of the engineering and administrative work, the engineer's role is reduced to that of generating the SOR, monitoring and intervening to make adjustments or corrections in the inputs/iterations as well as validating output. This also means that there is less chance of work falling through the cracks.

3.6.2 The role of contractors in digital well planning

In traditional well completion planning, the completion engineer acts like the project manager and connection point between service companies and the operating company. In digital well planning however, an alliance contract model serves the projects best. This is because it allows more fluidity and the teams have access to the well planning hub.

The collaboration with service company engineers is essential in efficient well delivery right through planning to execution. They understand their tools and their operational limits better. Because of the difference in operating principle of the different completion equipment supplied by the service companies, the calculations involved, operating environment and deployment method have to be adjusted to suit the supplier specific completion equipment i.e. what rig handling equipment is required.

Because there is already a service contract in the system, the service company engineers can be granted role specific access to the system and add the required parameters for their completion tool. These parameters are then automatically included in the well completion program for example.

Chapter 4

Illustrating digital well completion planning for sand control

The digital planning process begins by extracting necessary data from the reservoir, geophysics and drilling modules as shown in figure 4.1

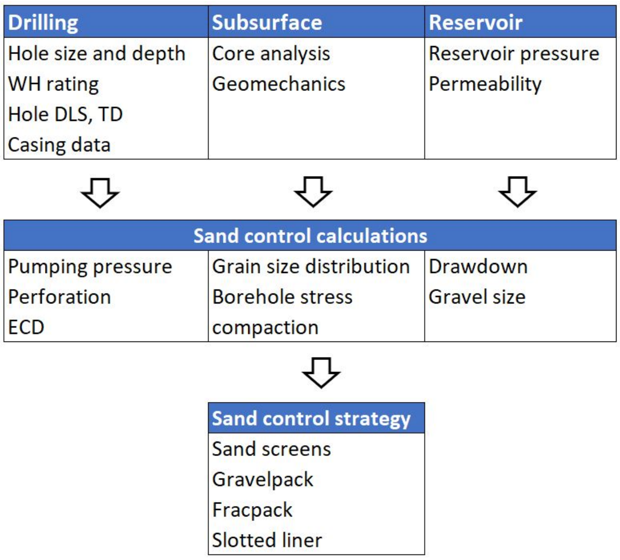

Figure 4.1: Illustration of input data for sand control

Sand production is one of the leading production problems in sandstone reservoirs. Some of the challenges with sand production are:

- Plugged perforations
- Total sand-face collapse leading to loss of the well
- Damage of surface facilities due to erosion
- Erosion of the completion components

Therefore, it's desirable to reduce sand production wherever it's technologically and economically possible with either passive or active sand control mechanisms,

4.1 Program description and tools

The sand control decisions were first expressed in a flowchart as shown in figure 4.2 the derivation of which can be found in appendix A

The sand control process usually begins with predicting sand failure based on the pore pressure, geomechanics stresses and drawdown as described in appendix A. If sand production is predicted, choosing a sand exclusion strategy involves core analysis to determine the particle size distribution, sorting and fines content.

A simple python program was written to aid in sand production prediction and selecting sand control strategy using analytical equations and best practice design recommendations. It begins by importing formation and production rate data. It also imports a core lab sieve analysis file and generates the particle size distributions. Based on this data, it determines whether they'll be sand production or not. If sand production is predicted, sand exclusion strategy between SAS, expandables and gravel pack is recommended.

Common sand control installation procedures were also loaded in text and the program automatically shows these procedures by prompting for the sand control objective/activity at hand.

4.2 Investigating sand production

Assume a single vertical production well with the reservoir data obtained and shown below in table 4.1

Table 4.1: Reservoir and subsurface data

Property	Value	Units
Fluid density	4.50e3	Pa/m
Production duration	5	years
Reservoir pressure	1.05e8	Pa
Depletion	2.0e7	Pa/year
Vertical stress	2.26e4	Pa
TVD	5000	m
Reservoir top	4850	m
TWC	3.0e7	Pa

Then the probability of sand production is determined from the sand control engineering module. This was achieved by a python program in appendix xx which compares rock strength (TWC) with the effective vertical stress σ_v.

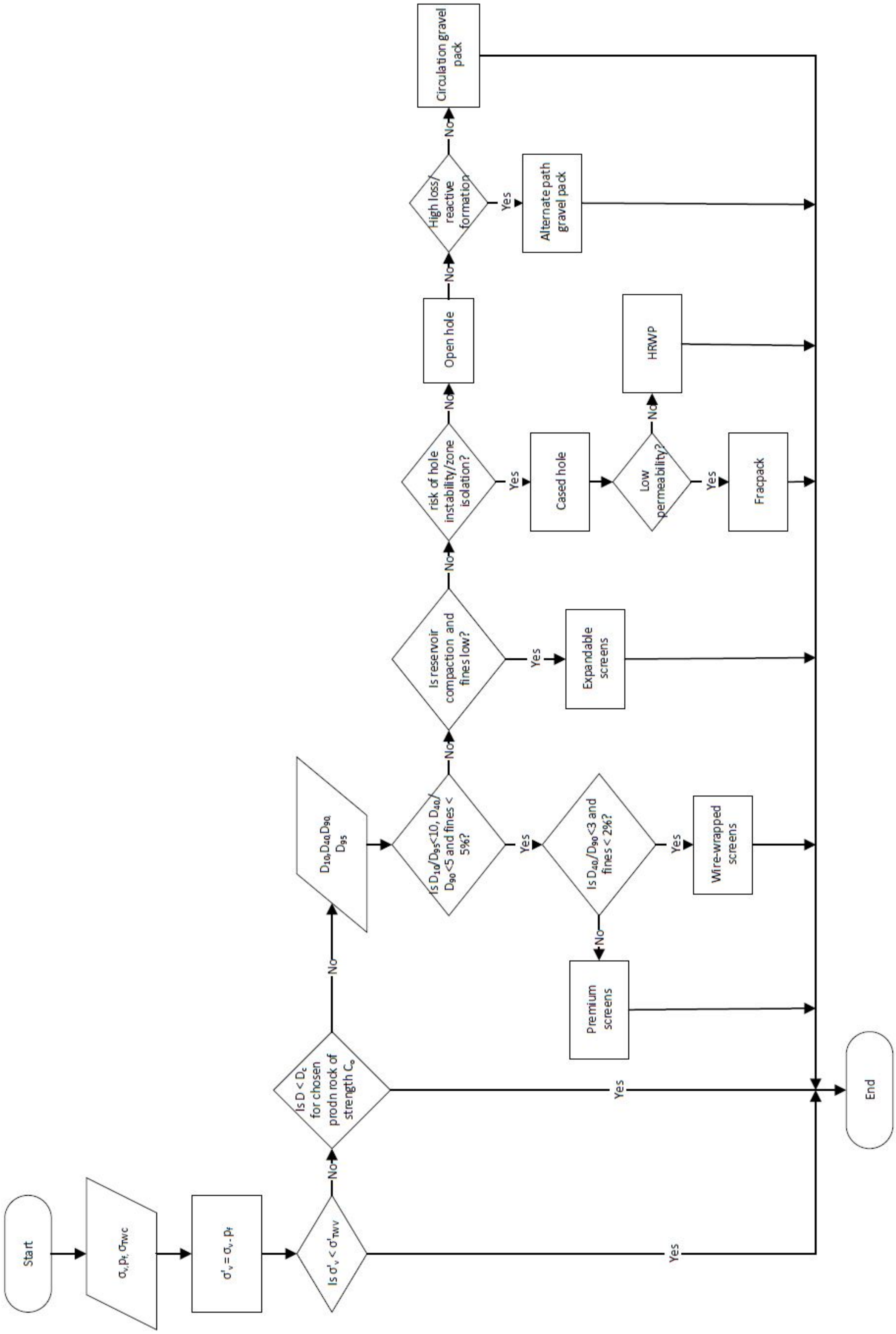

Figure 4.2: Sand control decision tree

This comparison is done for every year in a 5 years production life with consideration of pore pressure reduction as a result of production.

```
year 1
No sand production expect
year 2
Sand production expected
year 3
Sand production expected
year 4
Sand production expected
year 5
Sand production expected
```

Figure 4.3: Onset of sand production

For this particular model, the sand production happens in the 2nd year of production, way early into the expected lifetime of the well.

While this should normally be confirmation for sand control installation, another step would be to limit the plateau production rate to exert drawdown lower than the critical drawdown of the formation. To illustrate this a production rate of 16.4 sm3/d doesn't cause sand production. However, if the rate is changed to 327.7 sm3/d, sand production occurs since the critical draw down of 342.22MPa. See table 4.2.

Table 4.2: Sand production changes with flowrate drawdown

Production rate/sm3/d	Drawdown	Sand production
50	20.79	No
1000	1415.84	Yes

4.3 Choice of sand control method

If sand production occurs at the desired production rates, then the program can determine the type of sand production technology to deploy.

This begins by importing the sieve analysis data into the program. This example assumes a single core was used for the sieve analysis to represent the grain size distribution of the sand producing formation in question as shown in table 4.3.

With this, the program generates the resulting grain size distribution as shown in figure 4.4 in which the cumulative grain weight is plotted against the grain diameter in the representative sample.

The key distribution values usually used for analysis are the D10, D40, D50, D90 and D95 values and these are calculated and produced as in the program output in figure 4.5.

It's from these distributions that the program gives a sand control recommendation

Table 4.3: Sieve analysis datas

Sieve aperture, um	Retained weight,g
1000	0.000
500	0.009
250	0.039
125	5.234
63	13.625
38	0.845
15	0.617
10	0.060

Figure 4.4: Formation grain size distribution

```
D10 = 202.36
D40 = 111.85
D50 = 102.55
D90 = 65.37
D95 = 48.19
Uniformity Coefficient(D40/D90) = 1.71
Sorting Coefficient(D10/D95) = 4.20
Fines content = 3.31 %
```

Figure 4.5: Distribution parameter output

amongst the common sand control strategies i.e

1. stand-alone screens
    - Premium screens
    - Wire wrap screens
    - Expandable screens
2. Gravel pack
3. Fracpack

For this particular distribution, for openhole (figure 4.6) gravel packing with gravel size 615.33μm and sand screen aperture 461.50μm was recommended based on explanation appendix A

```
Enter openhole or casedhole openhole
Gravel pack of size  615.33 and screen of aperture 461.50  recommended
```

Figure 4.6: Open hole sand control recommendation

If the well was cased hole (figure 4.6), then high rate water pack with same gravel size of 615.33μm and sand screens of 404.71μm would be used.

```
Enter openhole or casedhole casedhole
HRWP-high rate water pack with gravel size 615.33 and screen size 404.71 recommended
```

Figure 4.7: Cased hole sand control recommendation

Because the fines content was 3.31% (between 2-5), the premium sand screen would be used in the gravel pack. More information on the criteria for selection of gravel and screen types and sizes based on the grain size distribution is elaborated in appendix A.

As we can see, the digital tool reduces the number of manhours that would be spent on planning by making the process automatic and eliminating errors from manual calculations.

4.4 Contracts and equipment selection

Before operations commence, contracts are awarded for execution of well construction activities such as rig contracts, completion, perforation and logging contracts. In digital operations planning for every activity description in the procedure, the relevant contract related to this particular activity is called. The equipment, number of personnel, type of service and their related rates can then be checked in the digital contract. The contracts and associated equipment are already stored in the database. These are called up depending on the operation to be performed.

Now that we know what sand control strategy is to be implemented (gravel pack with premium screens), the relevant detailed equipment is populated from the completion contract in the system.

4.5 Automated well schematic

We also know that the hydrocarbon thickness is 150m, the corresponding equipment along the entire length of the completion can be loaded from the completion contract to make a schematic of the sandface completion as shown in figure 4.8

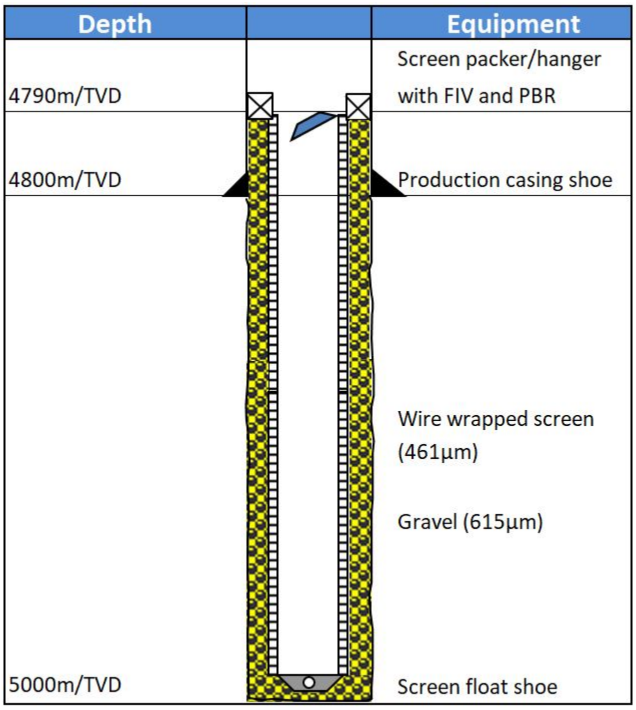

Figure 4.8: Lower completion schematic

During operations, the gravel pack BHA and wash assembly can be similarly generated from the contract as shown below. This is from experience and machine learning especially in fields where the completions and BHA assemblies are standardized. Consequently, the completion engineer can override the automated process and perform the selection manually from predefined BHA assemblies.

4.6 Digital completion program with sand control

Writing well completion procedures is one of the most repetitive tasks that is done from one well to another. In this sand control operations planning example, we show that it's possible to make a detailed sand control procedure that can be generated automatically.

Generating the digital completion program starts with an initial program rev0 based on standards and company policies. This is further improved by engineering rules and experience from previous operations. Figure 4.9 illustrates this

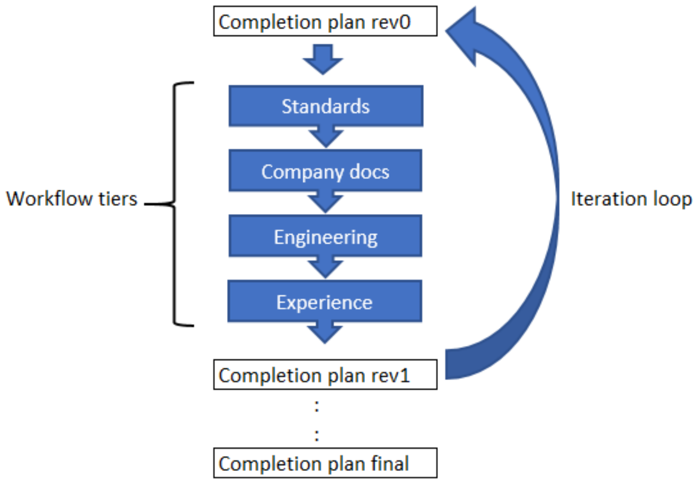

Figure 4.9: Iteration illustration

This section will focus on the initial well completion program rev0 and operational planning for gravel pack. The generic procedure outlines is usually as follows:

1. Prepare the well.
2. Change handling equipment
3. PU and MU screens and float shoe
4. RIH screens and wash pipe assembly and packer
5. Set gravel pack packer
6. Perform gravel pack
7. POOH running tool with wash pipe
8. RIH and install upper completion

All possible combinations are input, and these are used to make the initial procedure. These procedures are based on available standards like the NORSOK D010 for well integrity at all times and company documents based on experience and best practice procedures.

4.6.1 Prepare the well (Procedure #1)

Procedure:

1. PU/MU scraper,magnets and junk basket with bit
2. RIH and scrape packer setting depth
3. Displace well from drilling mud to brine

4. POOH and lay down scrapper BHA

Contract and equipment: Rig contract
Engineering: Swab and surge, well control, casing wear, ECD

4.6.2 Change handling equipment (procedure #2)

Because the profiles and size of the screens are different from most common tubulars on the rig such as drill pipe and tubing, the handling tools e.g lift sub and safety clamps have to be changed to be able to pick up the screens to avoid screen damage.

4.6.3 Pick up and Make up screens (procedure #3)

Procedure:

1. Pick up the individual screens from the pipe rack onto the drill floor taking care not to damage the screens, remove screen wrapping. Drift equipment
2. Make up the float shoe with blank pipe on the first screen joint. Connect screens with flapper and RIH as per BHA tally.
3. Insert wash pipe assembly inside screens.
4. PU and MU gravel pack packer.

Contract and equipment: rig and completion contract - screens and wash assembly, packer, mule shoe.
Engineering: surge and swab.

4.6.4 RIH lower completion assembly (procedure #4)

Procedure:

1. RIH the gravel pack assembly with good tripping practice (2min/joint) according to BHA and rig pipe tally to surface
2. Circulate hole and monitor fluid loss rate

Contract and equipment: Completion and rig contract.
Engineering: surge and swab, torque and drag, well control.

4.6.5 Set packer (procedure #5)

Procedure:

1. Rig up gravel pack equipment
2. Manipulate downhole equipment to open screen annulus
3. Perform circulation test
4. Circulate gravel until screen out. Bleed off pressure
5. Manipulate downhole equipment to close screen annulus
6. Reverse circulate excess gravel from work-string

Contract and equipment: Completion and rig contract - packer,drill pipe.
Engineering: packer forces, tubing stress, hydraulic.

4.6.6 Perform gravel pack (procedure #6)

Procedure:

1. Rig up pumping head and surface lines
2. Pump setting ball and pressure work string (e.g 4000psi) to set packer. Confirm packer set with overpull
3. Bleed off pressure
4. Close BOP and pressure test packer-tubing annulus.

Contract and equipment: Completion and rig contract. screens,gravel, rig pump, manifolds, data acquisition.
Engineering: Formation mechanics, packer forces, tubing stress, hydraulic.

4.6.7 POOH service tool and wash pipe (procedure #7)

Procedure:

1. Release service tool with overpull
2. POOH to surface and LD running tools

Contract and equipment: Completion and rig contract. DHSV, SPM, SSD chemical injection,tubing and PBR, TH and XT.
Engineering: torque and drag, casing wear, tubing stress, hydraulic.

4.6.8 RIH and install upper completion (procedure #8)

Procedure:

1. PU and MU PBR, tubing joint and SSD
2. RIH with tubing and make up chemical injection sub with control line
3. PU/MU SPM for gas lift and continue RIH with tubing

4. Connect DHSV with control line
5. PU and MU tubing hanger to tubing
6. Land tubing hanger in tubing head spool and sting PBR into packer
7. Pressure test seal assembly

Contract and equipment: Completion and rig contract.
Engineering: torque and drag.

For the automated program, the common phases/events and procedures are already preset in the software. At an advanced level however, activity codes can be used to identify activities. In figure 4.10 for example, if a completion phase "preparing the well" is identified by code PR, the program looks for the procedure related to this code and generates the "procedure 1"

	Phase	Procedure	Contr & Equip	Engineering	Code
1	Prepare the well	Procedure #1	Rig	S&S, ECD, casing wear, well control	PR
2	Change handling equipment	Procedure #2	Rig, Completion	N/A	HE
3	PU and MU screens and mule	Procedure #3	Rig, Completion	S&S	IGM
4	RIH screens and wash pipe assembly and packer	Procedure #4	Rig, Completion	T&D, S&S, casing wear , well control	IGR
5	Set gravel pack packer	Procedure #5	Completion	S&S, hydraulic, Packer forces	IGS
6	Perform gravel pack	Procedure #6	Completion, fluids	ECD, hydraulic, Packer & tubing, well control	CS
7	POOH and LD RT and wash pipe	Procedure #7	Rig, Completion	T&D	POH
8	Install upper completion	Procedure #8	Rig, Completion	T&D	IC

PR	Prepare the well (Procedure #1)	Code
1	PU/MU scrapper and magnets with bit	
2	RIH and scraper packer setting depth	
3	Displace well from drilling mud to brine	
4	POOH and lay down scrapper BHA	

IGM	PU and MU screens and mule shoe (Procedure #3)	Code
1	Pick up the individual screens from the pipe rack onto the drill floor taking care not to damage the screens, remove screen wrapper. Drift equipment	
2	Make up the mule shoe with blank pipe on the first screen joint. Connect screens and RIH as per BHA	
3	Insert wash pipe assembly inside screens.	
4	PU and MU gravel pack packer	

IGR	RIH screens, washpipe and packer (Procedure #4)	Code
1	RIH the gravel pack assembly with good tripping practice (2min/joint) according to BHA in figure and rig pipe tally to surface	
2	Circulate hole and monitor fluid loss rate	

IGS	Set packer (Procedure #5)	Code
1	Rig up pumping head and surface lines	
2	Pump setting ball and pressure work string (e.g 4000psi) to set packer. Confirm packer set with overpull.	
3	Bleed off pressure	
4	Close BOP and pressure test packer annulus.	

CS	Perform gravel pack (Procedure #6)	Code
1	Rig up gravel pack equipment	
2	Manipulate downhole equipment to open screen	
3	Perform circulation test	
4	Circulate gravel until screen out	
5	Manipulate downhole equipment to close screen	
6	Reverse circulate excess gravel from work-string	

POH	POOH and LD RT and wash pipe(Procedure #7)	Code
1	Release service tool with overpull	
2	POOH to surface and LD tools	

IC	Install upper completion (Procedure #8)	Code
1	PU and MU PBR, tubing joint and SSD	
2	RIH with tubing and make up chemical injection sub with control line	
3	PU&MU SPM for gas lift and continue RIH with	
4	Connect DHSV with control line	
5	PU and MU tubing hanger to tubing	
6	Land tubing hanger in tubing head spool and sting PBR into packer	
7	Pressure test	
8	Install xmas tree	

Figure 4.10: Digital sequence of events using event/activity codes

4.7 Operations planning

During operations the software is used to monitor the different phases related to a particular event before starting an operation. From the main page of operational planning platform in figure 4.11, we can see that for this particular well completion phase in which the main objective is to run screens, the related events are as follows:

- **Completion:**
- **Section:** sand control
- **Objective:**Run screens
- **Event:** Running screens OH

In the operations, there's procedures which have been tried and tested in execution of the most common activities. These best-practice well completion procedures, detailed activities can be described for most operations. In the operations planning software, under the well completion phase, we can have different sections e.g

- Wellbore preparation
- Installing completion
- Sand control
- Well testing
- Suspension
- Tieback

If for example we are in the sand control section of the operation we have the following objectives based on the different sand control strategies discussed earlier, i.e SAS, gravelpack, fracpack. See figure 4.11.

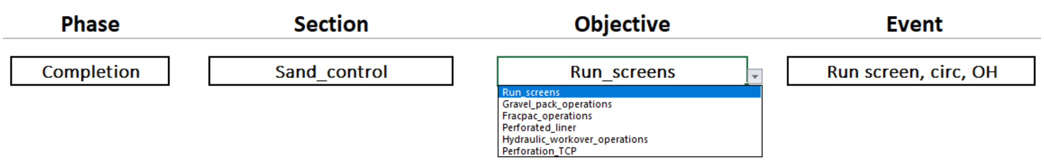

Figure 4.11: Sand control options/objectives

This is achieved by having all possible events, objectives and detailed activities related to the objective and they can then be populated in the event window to give the procedures as shown in figure 4.13. For example under completion in sand control, running SAS could have a best practice detailed procedure as shown below

SECTION	OBJECTIVE	Detailed ACTIVITIES
Sand_control	Gravel_pack_operations	stimulation/cleanup
Sand_control	Gravel_pack_operations	Inflow Test
Sand_control	Gravel_pack_operations	spot gravel
Sand_control	Gravel_pack_operations	squeeze
Sand_control	Gravel_pack_operations	circulation test
Sand_control	Gravel_pack_operations	data acquisition
Sand_control	Gravel_pack_operations	injection
Sand_control	Gravel_pack_operations	multizone Gravel Pack
Sand_control	Gravel_pack_operations	space out
Sand_control	Gravel_pack_operations	gravelpack_other
Sand_control	Gravel_pack_operations	Mob_demob
Sand_control	Fracpac_operations	Safety Related
Sand_control	Fracpac_operations	RU frac head and manifold
Sand_control	Fracpac_operations	RD frac head and manifold
Sand_control	Fracpac_operations	Pressure test
Sand_control	Fracpac_operations	Formation Strength/Limit Test
Sand_control	Fracpac_operations	Pump / Circulate / Displace
Sand_control	Fracpac_operations	Flowcheck
Sand_control	Fracpac_operations	Manipulate Downhole Equipment
Sand_control	Fracpac_operations	Set gravel pack packer

Figure 4.12: Sand control activities

4.8 Contracts

As seen in figure 4.13 above, for the "run screen while circulating" event, the completion and rig contracts are related to the particular event and they appear on the main page.

The outcome is the event and the detailed description as shown below

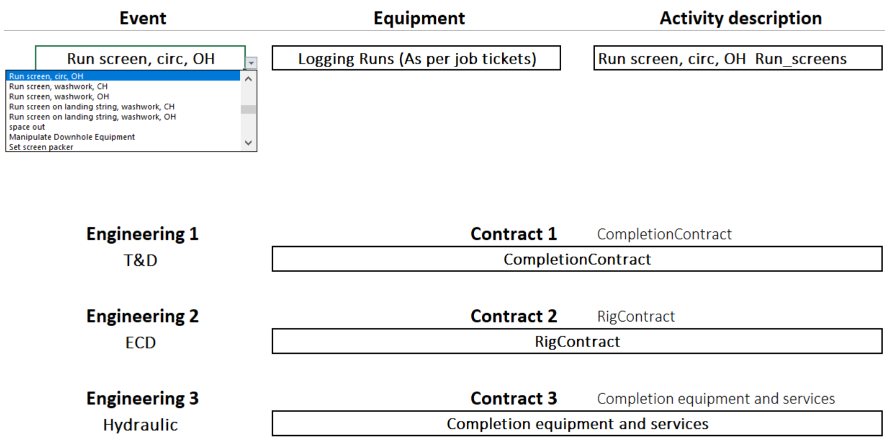

Figure 4.13: Event and detailed activities

4.9 Engineering

With digital well planning, the engineering involved in carrying out every activity stored and populated when needed. For example, if the operation involves pushing sand screens in open hole section of a deviated well, then the torque and drag (TD) engineering module related to that operation can be populated during the operation. Similarly, if circulation will be performed, equivalent circulation density ECD will be the relevant one. For general sand control operations such as running screens, the common calculations to ensure successful deployment of the completion are as follows,

Torque and Drag (T&D)
Torque and drag modeling is essential in sand control as it can determine the maximum depth that the screens can be pushed especially in horizontal drains. While tripping in casing, the only concern is the weight of the string. However, drag is important especially when RIH completion equipment in deviated open hole sections as it increases the hook load. From the drag model for a straight bore hole, string weight F (hook load) and Torque T are given by:

$$F = w(\cos\theta \pm \mu \sin\theta) \tag{4.1}$$

$$T = rw\mu \sin\theta \tag{4.2}$$

Where w is the submerged unit weight of pipe, r is the tool radius, θ is the deviation angle, μ is the coefficient of friction which in the opposite direction to string movement, + for picking up the pipe and - for lowering the pipe.

Equivalent Circulation Density (ECD)
ECD represents an increase in the bottom hole pressure as a result of pressure losses in the annulus.

$$ECD = MW + \Delta P_{ann}/(gTVD) \tag{4.3}$$

where MW is the mud weight, ΔP_{ann} is the annulus pressure losses and g is gravity. The goal is to keep pore pressure < ECD < fracture pressure.

Surge and swab (S&S)
This is especially important for open-hole completions e.g internal gravel pack when running or POOH tools. Surge increases hydraulic pressure on the formation causing losses in the well while swab reduces the hydrostatic pressure increasing potential for a kick. Hence this engineering module determines the tripping speed v_p. Assuming turbulent flow between the pipe and hole annulus, the surge or swab pressure is given by equation 4.4.

$$\Delta P_{S\&S} = \pm 2 f L \rho V^2/(d_1 - d_2) \tag{4.4}$$

Where $\Delta P_{S\&S}$ is the surge/swab pressure due to RIH/POOH respectively, f is the fanning friction factor, ρ the fluid density flowing at velocity V, flowing in a pipe of length L. d_1 and d_2 are the diameter of the hole and pipe respectively.

Figure 4.13 shows that for the "run screen while circulating" event, torque and drag, ECD and hydraulic pumping calculations are relevant to this operation while figure 4.14 illustrates the generated procedure and engineering for the sane activity activity "Run in hole" with code “IGR” from 4.10 in the "Run screens" objective.

```
Enter objective or activity code IGR

1       RIH the gravel pack assembly with good tripping practice
2       Circulate hole and monitor fluid loss rate

----------------------------------
Torque and drag:
Hook load =  1499517.36 N
Torque =  0.00 Nm
----------------------------------
Equivalent Circulation Density:
ECD = 1.03 sg
----------------------------------
Surge and swab:
surge/swab = 117647.06 Pa
```

Figure 4.14: Digital sequence of events and engineering involved

This standard procedure wouldn’t have to be rewritten as is the case in manual instructions.

4.10 Automation/process environment

As described earlier in 3.5.1, the process environment refers to the rig/unit/vessel tools that are required in carrying out a specific completion task. For completion in a specific task "Running screen while circulating OH", the process environment is:

- Screen handling equipment
- Running tools
- Rig pumps
- Rig tongs
- Slips
- Brine
- Pit and filtration system
- Top drive
- Pipe handler and racker

Chapter 5

Discussion

5.1 Method selection

The objective of the thesis assignment was to develop a workflow for digital well planning in completions. To illustrate how digital well planning works, logic and decision maps on which most completion designs are based and implementing this in python program for sand control selection was done. Python is an easy programming language and can easily be adopted by engineers to design other tools that can be added to the planning software. The digital experience however requires much time to be integrated in the planning and the experiences are so diverse from one company to another.

5.2 Effect of economics in well completion decisions

The examples in this thesis are based on completion choices and decisions based on engineering with input from subsurface data. While the completion engineer decides what completion hardware to be run in the well, project economics greatly affects what technology is deployed or what methods are used in executing/installing the completion. For example, for sour production exotic tubing like 13Cr can be used since it will give a longer service life in these production conditions, but deploying such tubing for many wells will greatly affect the project cost in the short run. In this case, if intervention costs are low, the operator might prefer to initially produce with L-80/C-95 to maximise initial cash-flow and replace the tubing at a later stage.

5.3 Analytic vs numerical methods

The engineering examples used in this thesis are based on analytic expressions. In a complex well design, numerical methods are more reliable and give more accurate results. Such is the case with torque and drag numerical analysis modeling of the borehole string or using advanced statistical models for sand particle size distribution as a single core may not be a full representation of a field's deposition environment.

5.4 Building on current planning software

There currently exists well engineering software for example Landmark EDT from Halliburton and DrillOps from Schlumberger. These tools are specifically focused on well engineering and already have many users familiar with their use. It could be possible learn from these and only include other modules such as contracts, equipment, reporting and experience. This would reduce the digital well planning software life-cycle. But currently the digital and automated planning application still requires significant man-hours before it is ready for use.

5.5 Transition to full automation

The aim of the thesis was to present a workflow for a digital well completion planning. However well completion is a complicated process that has too many variables and varies from location to location. While digital well planning has its benefits as highlighted throughout this thesis, human involvement is still essential for successful completion design as majority of experience is still with the experienced engineers. It would take a considerable time for machine learning to fully replicate what the human engineers can do successfully. Only if guided by physics and proper mathematical models can we shorten this machine learning curve (Staff *et al.* 2020).

Another word of caution is that automation is prone to "false-calls" where the sensors indicate something that may not be true during operations. As such it can paradoxically lead to more people being deployed to maintain these sensors compared to standard manned operations.

Chapter 6

Conclusion

Digitalization of processes is an essential part in today's 4th industrial revolution and is only expected to grow. To remain competitive, the oil and gas companies have to adapt the digital revolution and benefit from the value created, especially in well planning. In this thesis a workflow for digital well completion planning at the BOD stage and operation stage respectively with the goal of reducing well planning time and cutting out repetitive tasks done by engineers in the current don-digital well planning. The following points are however relevant to digital well planning

- As is the case with all digital systems, the quality of the output is as good as the input of the user. The choice of models for engineering computations also ultimately affects output accuracy/quality. And while digital experience is very useful in reducing well planning time, it cannot yet fully compensate for the lack of insight that comes with inexperience at the input. Hopefully this issue can be solved with machine learning algorithms as is the case with our mobile phones and robotic technology today to fully refine inputs.
- The engineers don't have to be experts in digitalization or programming to benefit from digital well planning. They are simply end users but with the capacity to choose engineering models and what best suits them.
- Digital well planning minimises planning time especially by eliminating the repetitive task and administrative work done by engineers during well planning.
- Human involvement is still required in the workflow presented in this thesis since certain tasks or reasons for activities are not always logic based. These include decisions due to economics, engineer's experience, weather or other non-engineering events that could affect processes.
- Having a collaborated planning platform would find application in today's work environment where the engineers may not be able to work in collocation due to covid issues. This would allow them to access data as it comes without the need to exchange emails for this

From all of this, itclear to see that the benefits of digital well planning far outweight the investment.

Chapter 7

Future work

7.1 Real-time cloud-based computing

Cloud storage technology is readily available and it's possible to have databases where all well data is stored, however making the engineering calculations fast on a cloud will enhance the centralized workflow concepts especially in time when collocation of the well engineering teams might not be ideal. Simple handheld HMIs can be used for inputs and the back-end engineering done on the cloud.

With cloud computing, during the drilling operation, the completion plan is automatically updated using realtime data from the changing well status and incorporates it in a new completion. Items such as cement tops, casing shoe points, DLS and other data from logs can greatly impact the completion design.

7.2 Merging the well planning software with the rig automation software

The automated drilling rigs use machine language in their robotics technology such examples are NOV's 'NOVOS'. In the future it should be possible for the well planning software to be merged with the rig automation software.

7.3 Extending completion program to digital twin

Digital twin is a new technology where a virtual replica of the asset is stored onshore. Visualization of well completions would help in making better decisions especially at the SOR stage or during operation. Some companies are already in the early stages of this technology e.g Aker BP, Equinor and DNV and it's claimed to reduce well construction costs by as much as 25%. (Isbell *et al.* 2021)

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Appendix A

Designing for sand control

A.1 Sand production investigation

The vertical stress is the weight of the overburden given by

$$\sigma_v = gD\rho \tag{A.1}$$

Where ρ is the average density of the rock (e.g 2.3 for sandstone) g the gravity component and D the vertical depth of the overburden.

Pore pressure reduction with depletion should be determined for the entire productive life of the reservoir and the equivalent effective vertical stress determined especially for the later life as sand production intensifies with depletion.

$$\Delta p_f = \Delta\sigma \frac{C}{K} \tag{A.2}$$

Where $\Delta\sigma$ is the total stress, C and K are constants. The effective vertical stress σ_v' in the pay-zone is given by equation

$$\Delta P_f = \sigma_v - \alpha p_f \tag{A.3}$$

where p_f is the pore pressure at any given time in the production life of the reservoir and α is Biot's constant approximated to 1 henceforth.

To predict the likelihood of sand failure, the effective vertical stress is compared to the rock strength, represented by the thick wall cylinder test (TWC) stress determined from a core lab is or derived from density logs. if σ_v is less than TWC sand production can be ignored if σ_v greater than TWC, sand production expected.

If sand production is expected, the mitigation factors can be either passive or active sand control techniques

A.2 Passive sand control

Passive sand control techniques involve limiting the sand production without using direct sand barriers. The most common passive sand control techniques are:

A.2.1 Draw down reduction

In a producing well, the drawdown, Dd is the difference between the formation pressure p_f and the bottom hole pressure p_w.

$$Dd = p_f - p_w \tag{A.4}$$

As the drawdown increases, a critical value is reached at which enough force is generated on the loose sand grains at which point they get dislodged and start moving. Assuming cylindrical flow cavities, this critical drawdown is expressed by the equation.

$$D_c = (1 - v_f)(C_o - 2\sigma'_{is}) = A_1(sC_{TWC} - 2\sigma'_{is}) \tag{A.5}$$

Where v_f is the Poisson ratio (usually 0.3), C_o the unconfined rock strength of formation A1 is an empirical constant given by 1- v_f, s is a constant (usually 3.1) and σ'_{is} the effective in-situ stress expressed as

$$2\sigma'_{is} = 3\sigma_{max\perp} - \sigma_{min\perp} - 2p_f \tag{A.6}$$

where $\sigma_{max\perp}$ and $\sigma_{min\perp}$ are the maximum and minimum principle stresses in the direction of the flow cavity.

Sand arches can build over time and limit sand production, thus making the critical drawdown

$$D_c = 2C_o \tag{A.7}$$

But for the completion plan we shall consider a worst-case scenario where the sand arches don't form. The production strategy i.e natural rate and artificial lift should be planned such that critical drawdown on the reservoir D_c

A.2.2 Selective perforation, orientation and shot density

Having smaller perforation size to reduce produced sand volume probability especially in sandstone.

Matching the gun shot density with good phase angle allows for appropriate spacing between perforations and hence reduce sand production probability.

Assuming a standard 8 ½' production hole e.g 6spf at 99^o and 12spf at 143^o allows for 7.5' and 6' adjacent perforation spacing respectively.

Selective perforation (gun orientation) in only high rock strength parts of the reservoir can reduce the probability of producing sand. Assuming cylindrical perforation cavities, the critical drawdown is given by

$$D_c = A_1(C_o - 2\sigma'_{is}) + A_2 \supset C_o + A_2/A_1 = sC_{TWC} \tag{A.8}$$

Therefore, this expression can be re-written as

$$D_c = A_1(sC_{TWC} - 2\sigma'_{is}) \tag{A.9}$$

Where A_1 = empirical constant (1-ν_f), A_2 = empirical constant depending on rock plasticity and C_{TWC} is the maximum TWC stress from confined cylinder test

From equation A.9, the sand production risk is low if the perforation cavities are oriented in the direction of lowest in-situ stress because of a larger value for critical drawdown D_c and this critical drawdown is larger with stronger rock strength C_o. Thus we can only perforate in stronger parts of the reservoir and this is called selective perforation.

For purposes of simplicity, for a well along σ_h, this in the perforations would be in the direction of maximum stress σ_v

A.2.3 Active sand control

Active sand control implies installation of downhole hardware to mitigate flow and accumulation of sand into the well. Common sand control equipment include sand screens i.e stand-alone screens (SAS) and wire-wrapped screens (WWS). Gravel packing in which engineered gravel is placed behind screens to block sand particles whose size is larger than the gravel is also used in sand control.

Particle size distribution (PSD) and failure risk associated with each sand control method will determine the exclusion strategy. From the core laboratory PSD experiments, the PSD can be populated.

The D_{10}, D_{40} and D_{95} percentiles from the distribution are used to determine a suitable sand exclusion strategy. The sorting coefficient (SC) is the ratio D_{10}/D_{95} while uniformity coefficient (UC) is the ratio D_{40}/D_{90}.

Stand-alone screens (SAS)

Sand screens (SAS) are metal meshes welded to a slotted base pipe and run into the well with the aim of blocking reservoir sand from the flow stream. When installed as the sole sand exclusion mechanisms, they are referred to as SAS.

1. Wire-wrapped screens:
   This type of screen consists of a base pipe with holes and a single wire wrapped attached to the base. Selection criteria is given as:
   - $D_{10}/D_{95} < 10$
   - $D_{40}/D_{90} < 5$
   - fines content $< 5\%$
2. Premium screens:
   This type of screen consists of a woven mesh around a pre-drilled base pipe and a shroud on top for protection. This robust construction makes them a desirable choice in more harsh environments or where there's great potential for reservoir compaction e.g long horizontal drains. Selection criteria is given as:
   - $D_{10}/D_{95} < 10$
   - $D_{40}/D_{90} < 35$
   - fines content $< 2\%$

   Slot size $= 2D_{10}$
3. Expandable screens:
   Expandable screens consist of overlapping woven sheets covered between a slotted base pipe and shroud.
   While the annulus between formation and SASs makes them prone to rock failure around the screen due to lack of packing, expandable screens eliminate this and increase contact area with the formation. This is achieved by expanding the screens with a cone, pistons or hydraulic expansion tool until the screen touches the formation. It is worth noting that the reliability of expandable screens in open hole is similar to gravel pack and would be a preferred pick for cost reasons, barring compaction failure and high fines content..
   Slot size $= 1.5D_{10}$

A.2.4 Open-hole Gravelpack

Gravel packing is the practice of filling the void between the reservoir and well with sized gravel to stop production of formation sand and isolating the gravel from the well with sand screens of an aperture small enough to stop the placed gravel from entering the well.

In a situation where ieve analysis doesn't support SAS i.e the grainsize distribution is non-homogeneous and fines are very dominant the gravel pack sand control option desirable. The sand pack is designed to block large sand particles but allow fines to pass through.

Gravel size $= 1.5D_{10}$
Screen slot size $< 75\%$ of smallest gravel

A.2.5 Cased-hole fracpack

The aim of this operation is to fracture the formation, and pack the flow channels with gravel to keep them open and also to retain the formations and. It's therefore good for low permeability formations.

- The near wellbore damage is bypassed by the fractures
- it increases the contact area between the gravel and formation making it ideal for formations where fines invasion is a problem, consequently increasing productivity.
- Increased permeability and consequently the productivity through the fractured perforations

A.2.6 Fracture fluid design:

The fracture design can be based on the knowledge from 3.2.1 on hydraulic fracturing and it's worth noting that the fracture width should be big enough for increase productivity. the fracture propagation should not reach water zones above as fractures tend to propagate in the direction of lower stress.

A.2.7 Gravel/proppant selection:

- The gravel should withstand the closure pressure of the fracture e.g ceramic gravel
- To enhance larger flow channels, the grain size is usually 8-10 times the D_{50}
- To avoid early screen out due to frictional pressure drop, the clearance between the casing and screens is recommended to be $12D_{50}$

Appendix B

Drag model for Torque and drag

B.1 Straight bore hole

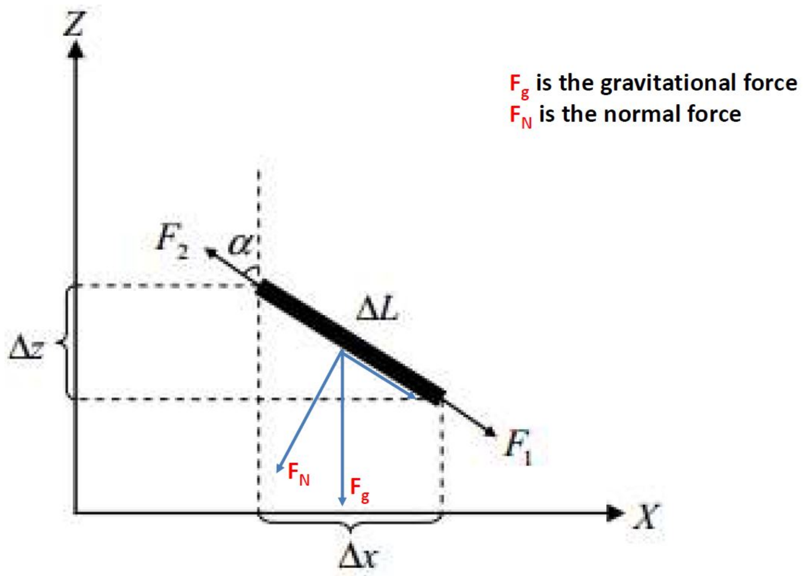

Figure B.1: Drag model straight borehole

$$F_2 = F_1 + w(\cos\theta \pm \mu \sin\theta) \tag{B.1}$$

$$T_2 = T_1 + rw\mu \sin\theta \tag{B.2}$$

B.2 Curved bore hole

$$F_2 = F_1 + w_{curve}(\cos\overline{\theta} \pm \mu N) \tag{B.3}$$

$$T_2 = T_1 + r\mu|N| \tag{B.4}$$

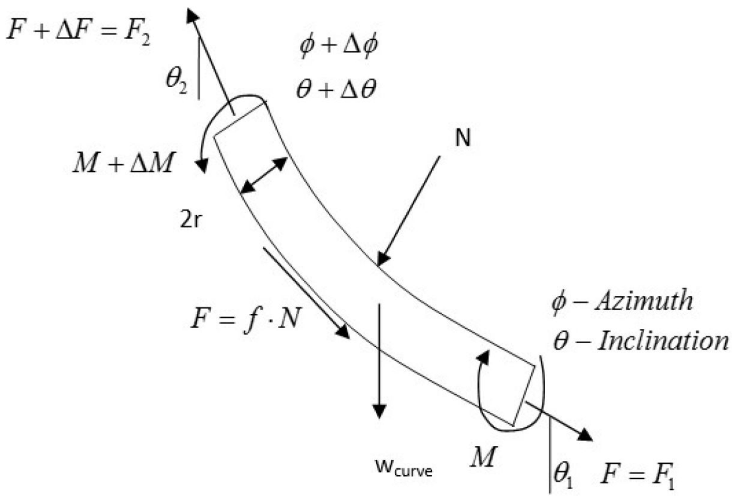

Figure B.2: Drag model curved borehole

where

$$N = [(F_1 \Delta\phi \sin\overline{\theta})^2 + (w \sin\overline{\theta} + F_1 \Delta\theta)^2]^{0.5} \tag{B.5}$$

For $\Delta\phi = 0$ i.e no change in azimuth, $N = \sin\theta + F_1\Delta\theta$

Where:
$\Delta\theta = \theta_2 - \theta_1$(radians)
$\Delta\phi = \phi_2 - \phi_1$ (radians)
$\overline{\theta} = (\theta_1 + \theta_2)/2$ (degrees)
$\overline{\phi} = (\phi_1 + \phi_2)/2$ (degrees)
$+$ sign is for pulling the string
- sign is for lowering the string
F - Friction force
T - Friction torque
r - radius of pipe/tool joint
μ - friction factor w - buoyed weight of pipe
w_{curve} - buoyed weight of the drill string from the lower to the upper end of the curved section of the borehole.

Appendix C

Completion decision flowcharts

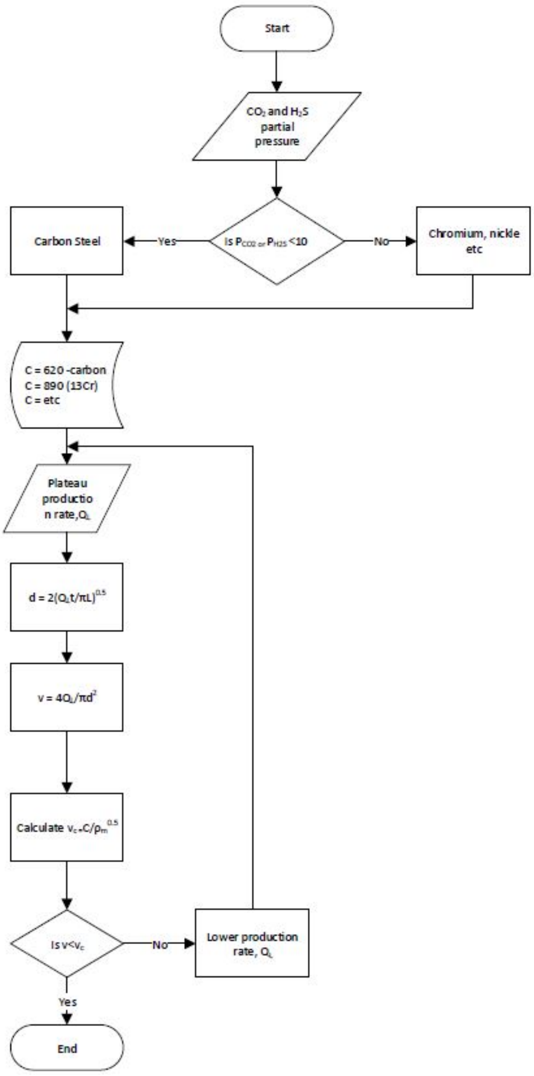

Figure C.1: Tubing size

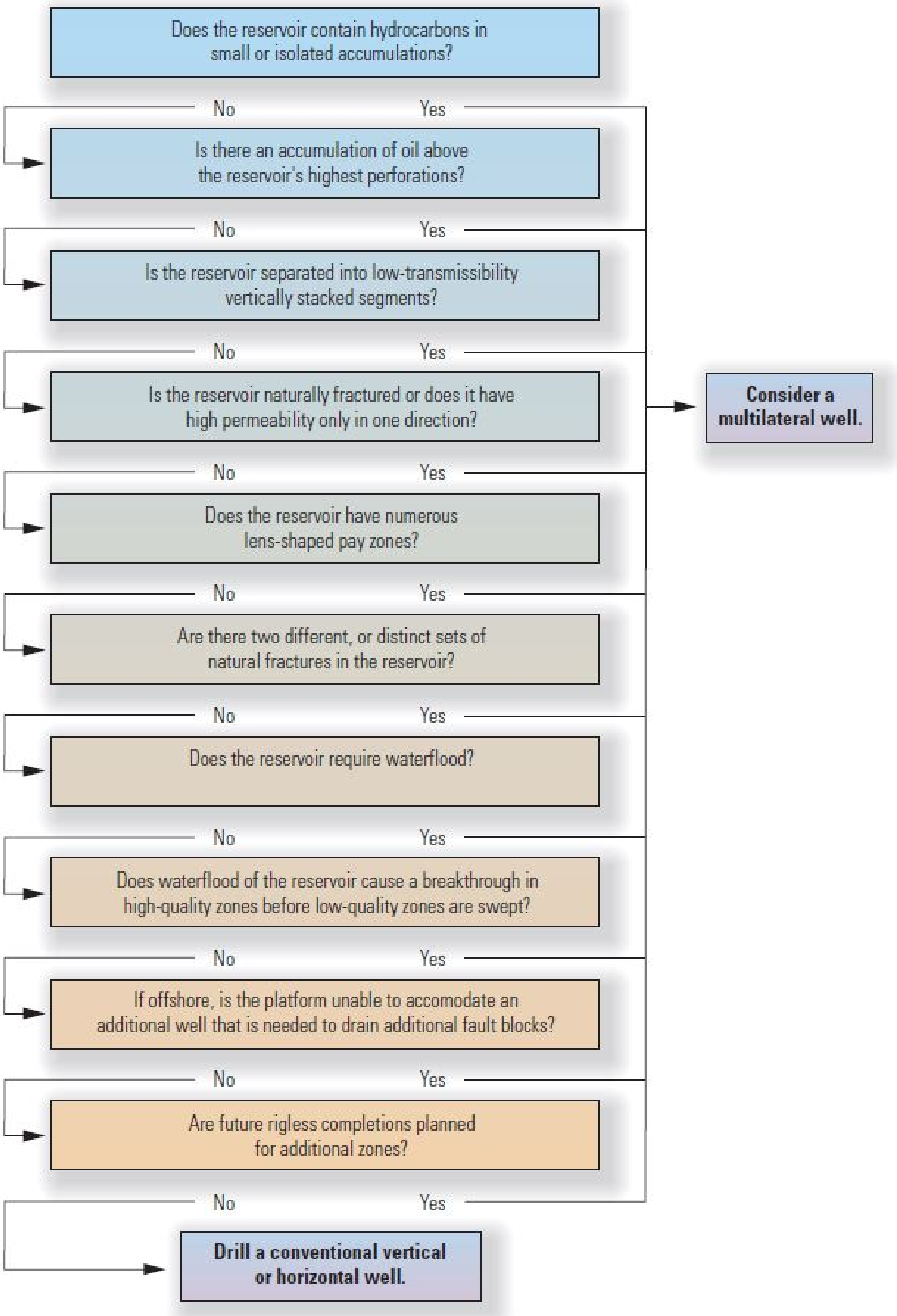

Figure C.2: Determining if MLT is applicable (from Bosworth *et al.* 1998)

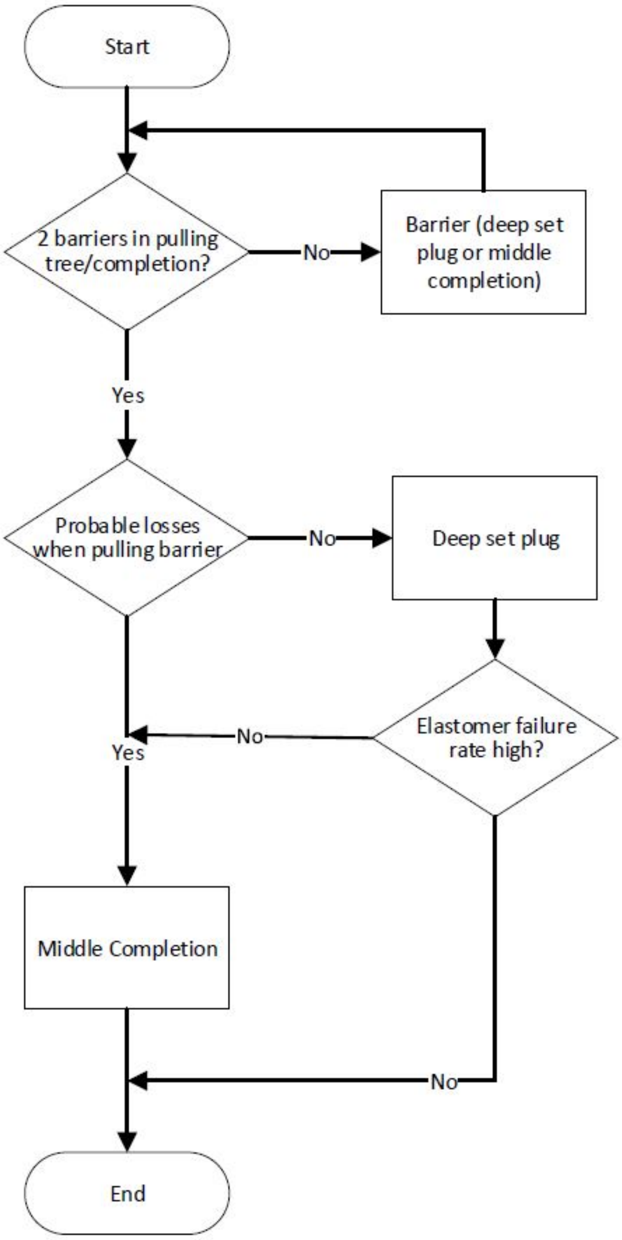

Figure C.3: Middle completion

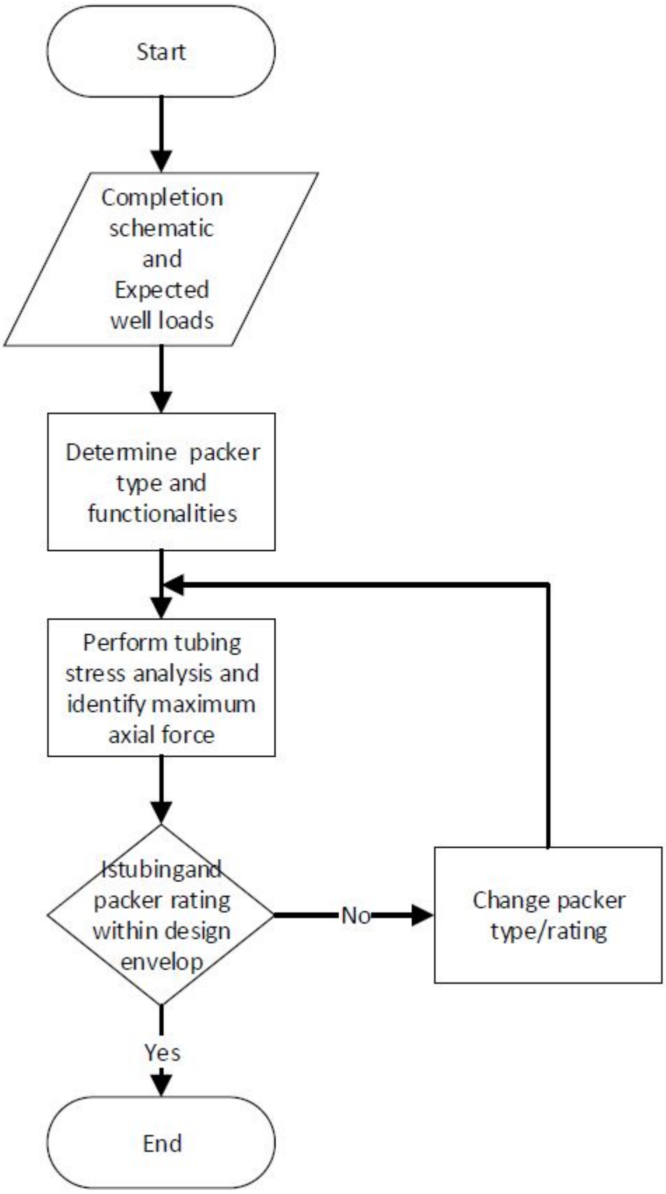

Figure C.4: Packer type

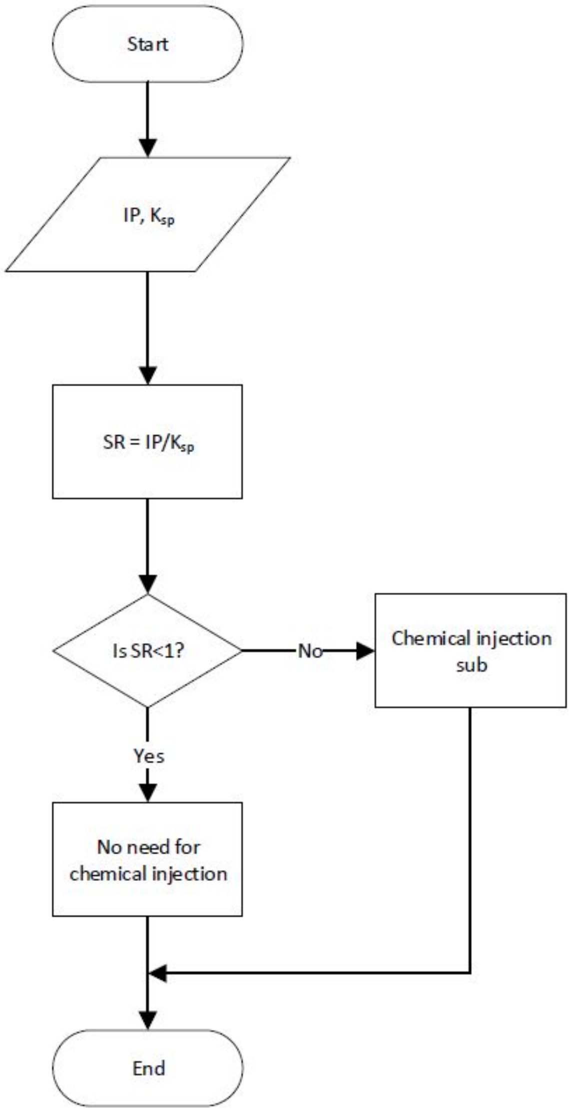

Figure C.5: Chemical injection

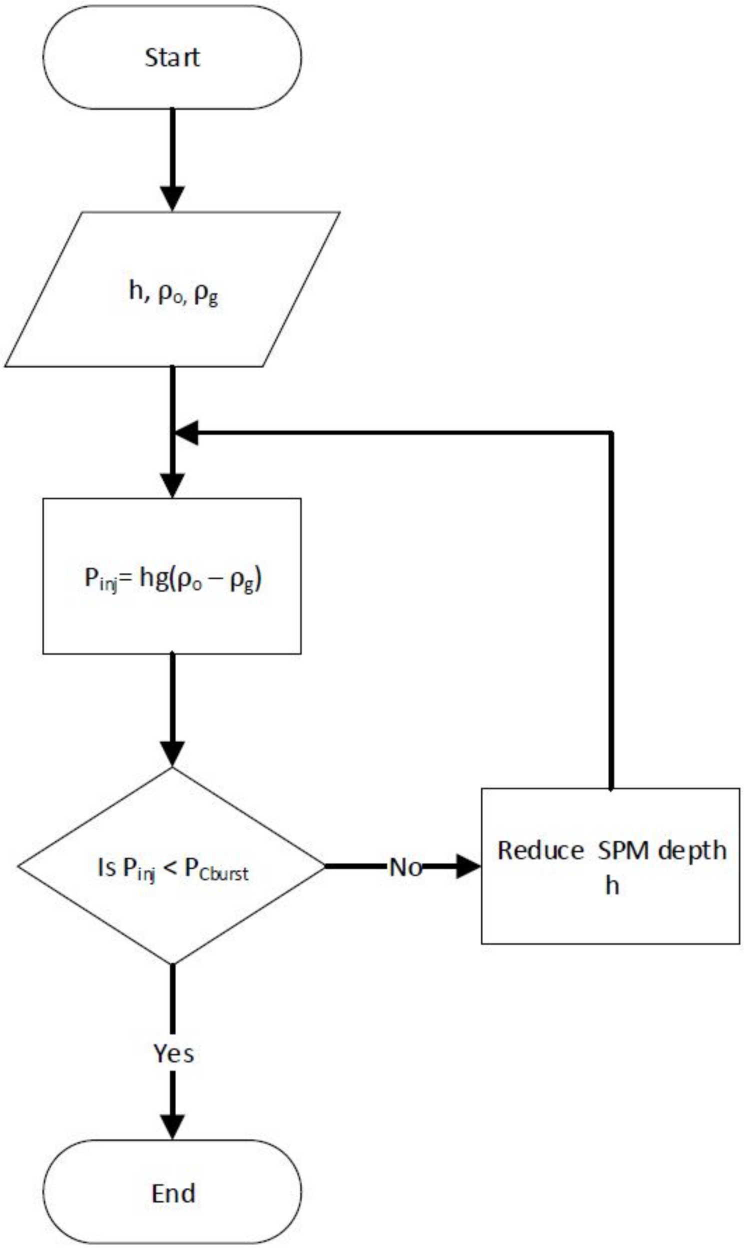

Figure C.6: Gas lift

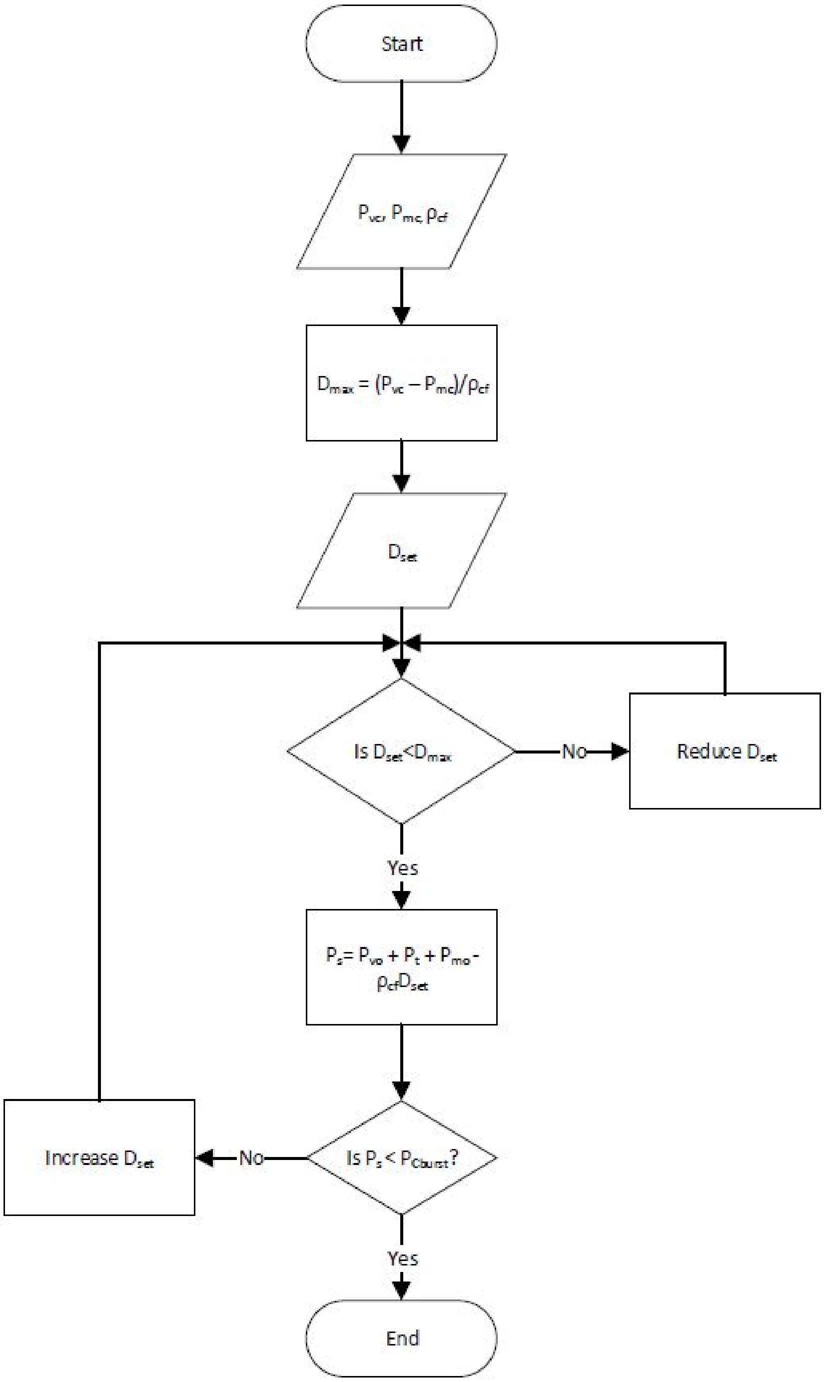

Figure C.7: Downhole safety Valve

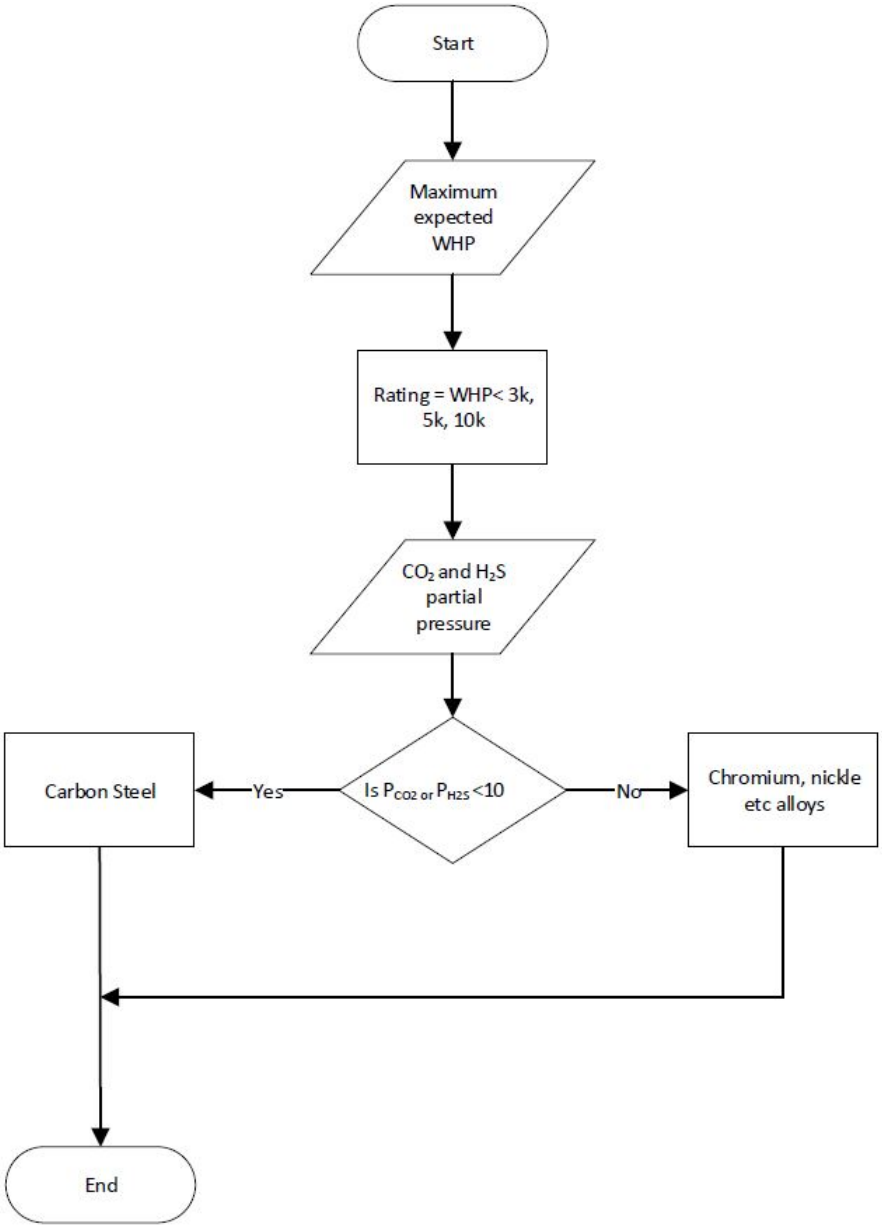

Figure C.8: Christmas tree

Appendix D

Code listing for sand control planning

In line with section 2.2.4, here's the Python code listing. All calculations are in SI-units

```
#libraties
import matplotlib.pyplot as plt #plotting library
import numpy as np #math operations library
import pandas as pd #table library
from scipy.interpolate import make_interp_spline, BSpline #interpolate
import scipy.interpolate #interpolation
from scipy import interpolate #interpolation2
from scipy.interpolate import interp1d
from scipy import stats #statistics
from statsmodels.stats.weightstats import DescrStatsW
import math
from math import sin, cos, tan
import decimal
import linecache
```

Code listing D.1: importing libraries

```
#sand likelihood function from effective stress
def sandlikelihood(years,pfi,pfr,vs,D,TWC):
    #years - number of years of production
    #pfr - depletion /pore pressure reduction per year
    #pf - initial pore pressure, Pa
    #vs - vertical stress from overburden, Pa/m
    #D - TVD, m
    #TWC - thick wall cylinder stress, Pa
    vsr=vs*D #vs - vertical stress
    pf=pfi-pfr*years
    evs=vsr-pf #evs - effective vertical stress
    if evs<=TWC:
        print ("No␣sand␣production␣expected␣because␣the␣effective␣vertical␣stress",
        "%.2f" %(evs/1e6), "MPa␣is␣less␣than␣the␣rock␣strength", "%.2f" %(TWC/1e6), "MPa")
    else:
        print ("Sand␣production␣expected␣because␣the␣effective␣vertical␣stress", "%.2f"
        %(evs/1e6), "␣MPa,␣is␣higher␣than␣the␣rock␣strength", "%.2f" %(TWC/1e6), "MPa
␣␣␣␣␣␣␣␣continue␣to␣drawdown␣check")
```

Code listing D.2: Sand likelihood function from effective vertical stress

```
#run vertical stress with reservoir data
years=5
pfi=105e6
pfr = 20e6
vs = 22.6e3
D = 5000
TWC = 30e6

n = 0
while n <= years-1:
    n = n + 1
    print("year", n)
    sandingchance1 = sandlikelihood(n,pfi,pfr,vs,D,TWC)
```

Code listing D.3: Investigate sanding from effective vertical stress function with reservoir input data

```
#sand likelihood function at plateau production rate
def criticaldrawdown(years,pfi,q,J,vf,Co,smax,smin):
    #pf - pore pressure
    #q - plateau production rate
    #J - productivity index
    #vf - poisson's ratio
    #Co - unconfined rock strength
    #smax - maximum perpendicular stress to flow channel
    #smin - minimum perpendicular stress to flow channel
    #pw - bottom hole pressure
    pf = pfi-pfr*years
    pw = pf-q/J #bottom hole pressure
    Dd = pf-pw #drawdown
    einsitu=(3*smax-smin-2*pfi) #effective insitu stress
    Ddc=(1-vf)*(Co-2*einsitu) #critical draw down
    #print(Dd)
    #print(Ddc)
    if Dd<Ddc:
        print ("No␣sand␣production␣expected␣because␣the␣drawdown", "%.3f" %(Dd/1e6),
        "MPa␣is␣less␣than␣the␣formation␣critical␣drawdown", "%.2f" %(Ddc/1e6), "MPa")
    else:
        print ("Sand␣production␣expected␣because␣the␣drawdown", "%.3f" %(Dd/1e6),
        "MPa␣is␣higher␣than␣the␣formation␣critical␣drawdown","%.2f" %(Ddc/1e6), "MPa")
```

Code listing D.4: Sand likelihood function at plateau production rate

```
#run drawdown with reservoir data
years=5
pfi=105e6
pfr = 20e6
smax = vs
smin = 22.4e3
q = 50*28316.84/86400 #sm3/d sand production increases with production rate
J= (2000/86400)/1e5 #sm3/s/Pa,J is usually in sm3/d/bar
vf = 0.2
Co = 8e6

n = 0
while n <= years-1:
    n = n + 1
    print("year", n)
    sandingchance2 = criticaldrawdown(n,pfi,q,J,vf,Co,smax,smin)
```

Code listing D.5: Investigate sanding at plateau production rate with reservoir input data

```
#Sieve analysis data
filesand = open('sieveanalysis.txt', 'r') #loading sieveanalysis file
sievedata = np.loadtxt(filesand,skiprows=3)

grainsize = sievedata[:,0] #microns
weight =sievedata[:,1] #grams
print(grainsize)
print(weight)

total = weight.sum()
pweight = 100*weight/total #percentage weights
pweights =pweight/100
cweight = np.cumsum(pweight) #cumulative percentage weights
```

Code listing D.6: Import sieve analysis data

```
#Particle/Grain Size Distribution (PSD)
plt.title("Grain␣Size␣Distribution", fontsize=15)
plt.plot(grainsize,pweight, linewidth= 2, color='k', label ='percentage␣weight')
plt.scatter(grainsize,pweight, color='k')
plt.plot(grainsize,cweight, linewidth= 2, color='darkorange', label ='cumulative␣weight')
plt.scatter(grainsize,cweight, color='k')

cweight_smooth=interp1d(grainsize,cweight,kind="quadratic")
grainsize_new=np.linspace(min(grainsize),max(grainsize),500)
cweight_new=cweight_smooth(grainsize_new)
plt.plot(grainsize_new,cweight_new, ':')

plt.xlabel('Grain␣Diameter,␣[microns]', fontsize=12)
plt.ylabel('Cumulative␣&␣percentage␣retained␣weight', fontsize=12)
plt.xscale("log")
plt.xlim(10,1000)
plt.ylim(0,100)
plt.grid(b=True, which='major', color='#666666', linestyle='-', alpha=0.5)
plt.minorticks_on()
plt.grid(b=True, which='minor', color='#999999', linestyle='-', alpha=0.5)

plt.legend(loc='center␣right', fancybox=True, framealpha=1, shadow=True, borderpad=0.5)

plt.axhline(y=10 , color='b', linewidth='1', label ='D10')
plt.axhline(y=40 , color='b', linewidth='1', label ='D40')
plt.axhline(y=50 , color='b', linewidth='1', label ='D50')
plt.axhline(y=90 , color='b', linewidth='1', label ='D90')
plt.axhline(y=95 , color='b', linewidth='1', label ='D95')
plt.axvline(x=40 , color='r', linewidth='1', label='fines')

plt.text(1000,10,'D10', fontsize=11)
plt.text(1000,40,'D40', fontsize=11)
plt.text(1000,50,'D50', fontsize=11)
plt.text(1000,90,'D90', fontsize=11)
plt.text(1000,95,'D95', fontsize=11)
plt.text(36,65,'Fines', fontsize=11, rotation = 'vertical')

plt.show()
```

Code listing D.7: Plot particle/grain size distribution

```
#Determining Uniformity & Sorting coefficcients, fines and compaction
distribution = scipy.interpolate.interp1d(np.cumsum(pweights), grainsize, bounds_error=False,
fill_value='extrapolate')

D10=distribution(0.10)
D40=distribution(0.40)
```

```
D50=distribution(0.50)
D90=distribution(0.90)
D95=distribution(0.95)

print("D10␣=", "%.2f" %D10)
print("D40␣=", "%.2f" %D40)
print("D50␣=", "%.2f" %D50)
print("D90␣=", "%.2f" %D90)
print("D95␣=", "%.2f" %D95)

UC = D40/D90
SC = D10/D95
fines = cweight[7]-cweight[5] #fines content 0r #fines = 100-D75] #fines content

print("Uniformity␣Coefficient""(D40/D90)""␣=", "%.2f" %UC)
print("Sorting␣Coefficient""(D10/D95)""␣=", "%.2f" %SC)
print("Fines␣content␣=", "%.2f" %fines, "%")
```

Code listing D.8: Determine distribution, sorting and uniformity coefficients of sand

```
#Compaction failure check
def compaction(years,pfi,pfr,h,vf,Efr,a):
    #h=reservoir thickness
    #dpf=pore pressure reduction
    #vfr=Poisson’s ratio
    #Efr=Young’s modulus of rock
    #a= alpha value estimated to 1
    dpf = pfi-pfi*years
    dh = (-dpf*a*h*(1+vf)*(1-2*vf))/(Efr*(1-vf))
    ratio=100*dh/h

    if  ratio<=2:
        print ("Reservoir␣compaction␣of", "%.2f" %dh,"m␣indicates␣a", "%.2f" %ratio,
        "%␣change␣in␣reservoir␣height␣implying␣a␣low␣risk␣of␣compaction␣failure")
    else:
        print ("Reservoir␣compaction␣of", "%.2f" %dh,"m␣indicates␣a", "%.2f" %ratio,
        "%␣change␣in␣reservoir␣height␣implying␣a␣high␣risk␣of␣compaction␣failure")
```

Code listing D.9: Reservoir compaction failure function

```
#Run compaction failure with formation and production data
years = 2
h=150
pfi=105e6
pfr = 20e6
vf =0.2
Efr= 6e9
a=1
perm = 300 #mD

compactionfailure=compaction(years,pfi,pfr,h,vf,Efr,a)
```

Code listing D.10: Investigate compaction failure for sand screens

```
#Sand control hardware selection
holetype=input("Enter␣openhole␣or␣casedhole");

if holetype=="openhole":
    if UC<=1 and fines<=1 and SC<10 and ratio<=2:
            print ("Expandable␣sand␣screen␣of␣aperture", "%.2f" %(1.5*D10), "recommended")
    elif 1<UC<3 and 1<fines<=2 and SC<10 and ratio>2:
            print ("Wire␣wrap␣sand␣screen␣of␣aperture", "%.2f" %(2*D10), "recommended")
    elif 3<=UC<5 and 2<fines<5 and SC<10 and ratio>2:
```

```
            print ("Premium␣sand␣screen␣of␣aperture", "%.2f" %(2*D10), "recommended")
    else:
            print("Gravel␣pack␣of␣size␣", "%.2f" %(D50*6), "and␣screen␣of␣aperture", "%.2f"
            %(0.75*6*D50), "␣recommended")

if holetype=="casedhole":
    if perm <=200: #base permeability
        print("FRACPAC␣with␣gravel␣size␣", "%.2f" %(10*D50), "␣and␣screen␣size", "%.2f"
        %(2*D10),"recommended")
    else:
        print("HRWP-high␣rate␣water␣pack␣with␣gravel␣size", "%.2f" %(6*D50), "and␣screen␣size",
        "%.2f" %(2*D10), "recommended")
```

Code listing D.11: Sand control hardware selection

```
#Engineering module for operations
def torqueanddrag(m,L,  ,  ,  ,r):#Torque and drag analysis

    F = (9.81*m*L*beta)*(math.cos(math.radians(theta)) -   *math.sin(math.radians(theta)))
    #total hook load

    T = (9.81*m*L*beta)*mhu*r*math.sin(math.radians(theta)) #T=torque

    #m = mass per unit length section, kg/m
    #L = length of string in section, m
    #beta = bouyancy factor of steel
    #theta = inclination angle
    #mhu = coefficient of friction, considered 0 in cased hole, - for RIH and + for POOH
    #r = washpipt/tubular nominal radius
    print ("Hook␣load␣=␣","%.2f" %F, "N")
    print ("Torque␣=␣", "%.2f" %T, "Nm")

def ecd(mw,dpann,TVD): #ECD
    ECD = mw + dpann/(9.81*TVD)
    ECDSG = ECD/1000
    print ("ECD␣=", "%.2f" %ECDSG, "sg")

    #ECD = Equivalent circulation density
    #mw = mud weight
    #dpann = annulus pressure losses
    #TVD = True vertical depth

def surgeandswab(f,L,rho,V,d1,d2): #S&S
    SS = (2*f*L*rho*V**2)/(d1-d2)
    print ("surge/swab␣=", "%.2f" %SS, "Pa")
```

Code listing D.12: Engineering module example for sand control operations

```
#input for engineering module
m = 34.74
L = 5000
beta = 0.88
theta = 0
mhu = 0.3
r = 0.128
mw= 1000

HPP = 3400000
TVD = L
dpann = 0.5*HPP

d1= 0.216 #8-1/2" hole
d2= 0.114 #4-1/2" screens
```

```
rho= mw/1000
f =
V = 2
```

Code listing D.13: input data for engineering module operations

```
#Well completion Program
preparewell = open('procedure␣#1.txt', 'r')
handlingequip = open('procedure␣#2.txt', 'r')
PUMU = open('procedure␣#3.txt', 'r')
RIH = open('procedure␣#4.txt', 'r')
packer = open('procedure␣#5.txt', 'r')
GP = open('procedure␣#6.txt', 'r')
POOH= open('procedure␣#7.txt', 'r')
objective=input("Enter␣objective␣or␣activity␣code");
if objective=="preparewell" or "PR":
        print (preparewell.read())
        print ("ECD")
elif objective=="handlingequip":
        print (handlingequip.read())
elif objective=="PUMU" or "IGM":
        print (PUMU.read())
elif objective=="RIH" or "IGR":
        print (RIH.read())
        print ("----------------------------------")
        print ("Torque␣and␣drag:")
        TD = torqueanddrag(m,L,beta,theta,mhu,r)
        print ("----------------------------------")
        print ("Equivalent␣Circulation␣Density:")
        circdensity = ecd(mw,dpann,TVD)
        print ("----------------------------------")
        print ("Surge␣and␣swab:")
        DP = surgeandswab(f,L,rho,V,d1,d2)
elif objective=="packer" or "IGS":
        print (packer.read())
        print ("----------------------------------")
        print ("hydraulic␣packer␣forces:")
elif objective=="gravelpack" or "CS":
        print (GP.read())
        print ("----------------------------------")
        print ("Formation␣calculations")
elif objective=="POOH" or "POH":
        print (POOH.read())
        print ("----------------------------------")
        print ("Torque␣and␣drag:")
        TD = torqueanddrag(m,L,beta,theta,mhu,r)
        print ("----------------------------------")
        print ("Surge␣and␣swab:")
        DP = surgeandswab(f,L,rho,V,d1,d2)
else:
        print("Enter␣valid␣objective")
```

Code listing D.14: Digital well completion program

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