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Evaluation of Work Flow in Drilling and Completion

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Summary

Integrity verification is essential to safe planning of wells. Although the complexity of wells has increased over the last decades, the process of integrity verification has not seen any significant changes. In order to reduce the number of engineering hours spent planning new wells, the work process, and corresponding engineering software needs improvements to be compatible with today's requirements.

In this thesis, tubing stress analysis and casing wear simulations have been conducted for an *High-Pressure High-Temperature* (HPHT) well on the Norwegian continental shelf using the industry leading software tools. Both the work process and engineering software have been subject to investigations.

The tubing sees excessive forces from high temperatures and high pressures in the well. In order to verify the integrity of the tubing, possible well scenarios are modelled in the Landmark WellCat software.

As the production casing serves as a well barrier during production, it is of high importance that casing wear does not compromise the integrity of the casing. Petris DrillNET has been used to model wear from drilling operations on the casings.

Improvements to the work process and engineering software are suggested in order to simplify the integrity modelling and reduce the engineering time spent on well planning. Based on the above mentioned work, the following points of improvement have been identified:

- Implementation of standards and technical requirements in the engineering software.
- Reduction of software input parameters through the establishment of a company specific database of parameters.
- Need for improved communication between software models to reduce the iterative nature of well planning.

Sammendrag

Integritetsverifisering er avgjørende for sikker planlegging av brønner. De siste tiårene har brønnenes kompleksitet økt betraktelig, men prosessen for integritetsverifisering har ikke endret seg nevneverdig. En oppgradering av arbeidsprosesser og teknisk programvare er nødvendig for å kunne forholde seg til økende brønnkompleksitet, og for å redusere antallet arbeidstimer brukt på brønnplanlegging.

Denne masteroppgaven tar for seg analysen av krefter på produksjonsrøret og slitasje på foringsrør for en brønn med høyt trykk og høy temperatur på den norske kontinentalsokkelen, ved hjelp av industriledende programvare. Både relevante arbeidsprosesser og programvare er undersøkt for å avdekke mulige forbedringsområder.

Produksjonsrøret er utsatt for store krefter grunnet høyt trykk og høy temperatur i brønnen. For å verifisere produksjonsrørets integritet, er alle sannsynlige scenario modellert i programvaren WellCat fra Landmark.

Produksjonsforingsrøret fungerer som en integritetsbarriere under produksjon. Det er derfor viktig at slitasje som følge av boreoperasjoner ikke kompromitterer integriteten til foringsrøret. Programvaren DrillNET fra Petris er brukt til å simulere slitasje fra boreoperasjoner på foringsrørene.

Forbedringer av arbeidsprosessene og den tekniske programvaren er foreslått for å forenkle prosessen med integritetsverifikasjon og redusere tidsbruken for brønnplanlegging. Basert på arbeidet beskrevet ovenfor er følgende blitt identifisert som forbedringsområder:

- Implementering av standarder og tekniske krav i eksisterende programvare.
- Reduksjon av mengde nødvendige data for simulering gjennom etablering av database med bedriftsspesifikke inn-data.
- Sikre bedre kommunikasjon mellom de forskjellige programvarene for å redusere behovet for iterasjon i brønnplanlegging.

Preface

This thesis is carried out at the Norwegian University of Science and Technology (NTNU), Department of Petroleum Engineering and Applied Geophysics and is the result of my work in the subject TPG4910 - Petroleum Technology - Drilling Technology, Master Thesis.

I would like to thank my supervisor, Professor Sigbjørn Sangesland for his guidance and help during these last months.

I would also like to extend my gratitude to my co-supervisor Bjørn Brechan at NTNU/Statoil ASA. His expertise and operational experience have been of great help and inspiration.

Lastly, I would like to thank Olav Westrheim, Tore Kolltveit and Mubashir Qamar of Statoil ASA, for facilitation and for sharing their experience.

I hereby declare that this thesis is made independently and in accordance to the rules and regulations of NTNU.

Contents

List of Figures

List of Tables

1 Introduction

The oil industry on the Norwegian Continental Shelf (NCS) has in later years increased its focus on drilling costs. Statoil and Petoro, the two largest license holders on the NCS, have both identified the rising development and production costs as an industry challenge (Petoro AS, 2014; Statoil ASA, 2014). Record high investments, combined with reducing production rates and a stable oil price, has led to a decreasing return on average capital employed.

As the complexity of new wells have increased over the last decades, the demand for intensive planning in order to have sufficient well integrity, has also increased. Insufficient well integrity can cause harm to personnel, equipment and environment and thus be a major expense for operators. Statoil has identified a significant potential in reducing well construction time and has estimated that a 25 % reduction in time is realistic through increased standardization and better planning of operations (Statoil ASA, 2014).

The production casing and tubing are important barriers during the production phase of a well. In HPHT wells the need for advanced analyses of tubing stresses are important to ensure sufficient well integrity. These analyses are conducted by drilling engineers, but their complex and work intensive nature leaves room for errors. In this thesis the author investigates the work process of tubing stress analysis, as well as casing wear simulations for the production casing by using the industry leading software tools. The processes, and theory behind, will be described and reviewed.

The emphasis of this thesis will be to identify potential time saving improvements in the work process of well planning. To understand the process, the author has in this thesis, together with the fall project, gone through the full integrity verification process for an HPHT well on the NCS. This thesis covers the following engineering tasks:

- Tubing stress analysis for an HPHT well using the industry leading software WellCat™.
- Casing wear simulation using DrillNET Casing Wear™.

2 Background

2.1 Thesis objective and approach

Reduced drilling efficiency is a big contributor to increasing costs. Figure 1 is an overview by Petoro on the increase in time for execution of standard drilling operations from 1992-95 to 2008-13 on the NCS. This increase has contributed to smaller margins for the operators.

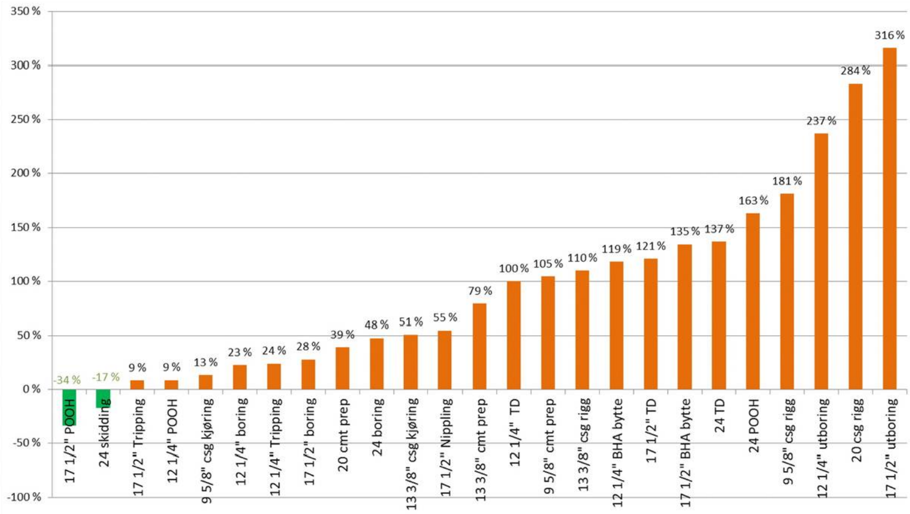

Figure 1: Increase in execution time for standard drilling operations the last 20 years (Teknisk Ukeblad, 2014)

In order to reduce drilling time the pressure on the drilling engineer to optimize planning increases. With high rig rates and costly offshore operations, small errors can have large economic consequences. Through this thesis, in addition to the autumn project report (Lokna, 2013), the author investigates the complete well integrity work process for a drilling engineer.

This thesis will investigate the casing wear analysis as well as the production tubing stress analysis for a recently drilled HPHT well on the NCS. These topics are vital for integrity verifications of a well. The natures of these simulations are complex and the software tools are unfamiliar for the average drilling engineer. Consequently, neither do the engineers feel comfortable running these simulations nor trusting of the results they get. This implies use of consultants and experts which in turn are cost driving.

For review of the work process of the wellpath design, torque and drag simulation, hydraulic simulations and casing design, the reader is referred to the autumn project report (Lokna, 2013).

2.2 Work process

The drilling of a well can be divided into three different phases: Planning, operational and post-operational. This thesis focuses primarily on the planning phase, as it is the most time consuming process. The planning time for a well depends on complexity, but planning time of one year or more is not uncommon in the industry. As the well construction has become more complex, the cost of planning has increased. Many of the tools used to plan the older and simpler wells have been modified over the years to adapt to the more modern and complex well construction. The planning process is much the same, only longer for each step as they become more critical. The phases along with the main steps for each phase is presented in figure 2.

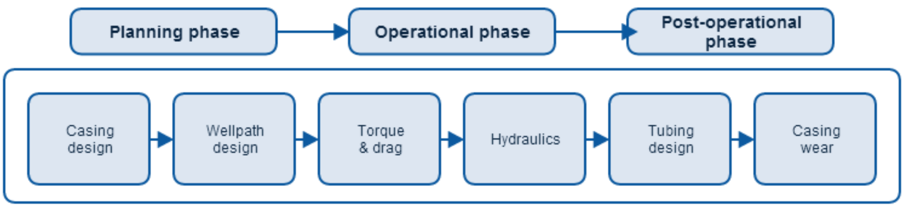

Figure 2: Work process in well planning

The planning stage is covered in detail through this thesis and the fall project. An overview of the work process can be seen in table 1.

The operational phase consists mainly of following up on the operations offshore. The models used in the planning phase must be updated with actual data. If actual data is different from the assumed factors, simulations should be

Table 1: Engineering steps for well planning.

Engineering	**Reviewed** in	**Software**	**Comments**
Wellpath	Fall project	Compass	Incl. alternative paths and relief well locations and paths
Casing design	Fall project	StressCheck	Some wells req. casing design to be done in WellCat
Torque & drag	Fall project	WellPlan	Design of drill string capable of handling down hole forces
Hydraulics	Fall project	WellPlan	ECD, pressure loss, flow rates and cementing
Casing wear	Thesis	DrillNET	Sliding wear from drilling operations
Tubing design	Thesis	WellCat	HPHT tubing stress analysis on NCS well

run again to ensure the integrity of the well. Table 2 presents the work process for a drilling engineer in the operational phase.

For the post-operational phase, the main task for a drilling engineer is to ensure that data about the well is correct and archived properly. Evaluation of operations, extraction of learning and sharing of experiences are central to ensure progress and that mistakes are not repeated.

2.3 Case description

2.3.1 Formation Characteristics and reservoir fluid

The well (hereinafter referred to as Well X) investigated in this thesis is an HPHT well on the NCS. HPHT is defined by The Norwegian Oil Industry Association (OLF) as a well with a maximum shut-in wellhead pressure (SIWHP) above 69 MPa (690 bar) bar or a reservoir bottomhole temperature of 150^{o}c or higher (NORSOK D-010, 2004).

The primary objective of Well X is to be a gas and condensate producer from

Table 2: Engineering tasks during operational phase.

Engineering	**Comment**
Wellpath	Update with actual data form drilling/survey
Casing design	Verify pore pressure and fracture within design limits
Torque & drag	Update with up/down weights and actual friction factor
Hydraulics	Update simulations with ECD, hole cleaning and drill string design
Casing wear	Redo simulations with actual opeartion data (ROP, RPM and WOB)
Daily reporting	Ensure progress is kept, capture experience and monitoring of drilling parameters

formation *one*. The secondary objective is to investigate the presence of hydrocarbons in the deeper formations; *two* and *three*. The tertiary objective is to produce from formation *two* and *three*. Penetrating three different reservoir sections complicates the engineering of the well. The well has to be dimensioned for the highest pressures and temperatures it may see and produce. These are found in the deepest reservoir, formation *three*.

Well X is expected to produce gas/condensate. Maximum gas production is estimated to be 4,5 MSm3/day. The gas-oil rate (GOR) is expected to be in the area of 1 380 - 12 440 Sm3/Sm3. The production fluid composition used for integrity verifications are described in detail in appendix A.2.

Figure 3 shows the pore pressure and fracture gradients in the formations. As a result of the small mud weight (MW) window at appr. 3 900 mTVD, managed pressure drilling (MPD) might be necessary. MPD would require specific planning and is not covered in this thesis.

Selected design parameters are specified in Table 3. Formation *Three* will be the dimensioning formation. Due to blow-out contingencies, formation *One* have to be sealed off with a liner before drilling the lower reservoirs.

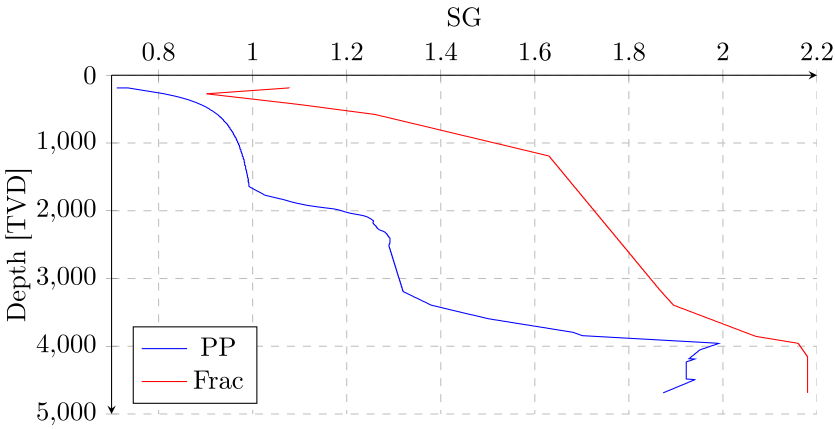

Figure 3: Pore pressure and fracture gradient.

2.3.2 Production Requirements

The production requirements are often dimensioning for the well size. In order to enable desired production rates, the production liner and tubing has to have a minimum size. The relationship between tubing radius and friction loss can be illustrated by the *Darcy-Weisbach equation*:

$$\Delta P = f_D \frac{L}{D} \frac{\rho V^2}{2} \tag{2.1}$$

where ΔP is the pressure loss, f_D is the dimensionless *Darcy friction factor*, L/D is the ration between length and diameter of the tubing, ρ is the fluid density and V is the average fluid velocity (Kamel, 2012). Equation 2.1 is valid for one-phase flow and thus not relevant for two-phase gas/condensate production, but it illustrates the relationship between pressure loss and tubing radius.

The tubing design requirements are summarized in Table 4.

2.3.3 Well Design, casing design and lower completion

Well X is an S-shaped platform well drilled down to a total depth of 5 996 mMD. The well starts to build inclination in the 24" section and builds to 30^o

Table 3: Design data for Well X

Data	**Unit**	**Reservoir**		
Formation		*One*	*Two*	*Three*
Water depth	m	133		
Reservoir depth	mTVD	3 962	4 192	4 476
Reservoir temperature	^{o}C	150	158	168
Reservoir pressure	bar	785	805	865
Max SIWHP	bar	679	705	736
WH flowing pressure	bar	657	682	713
WH flowing temperature	^{o}C	132	139	151

Table 4: Tubing design criteria

Size [in]	Depth [m]		Minimum safety factor			
	Start	End	Burst	Collapse	Axial	Triaxial
5 1/2	24	4 800	1,10	1,10	1,20	1,25
4 1/2	4 800	5 068				

before setting the 20" casing. The building continues in the 17 1/2" section until the sail angle of 47^{o} is reached. Slight changes in azimuth and inclination are planned in the 12 1/4" section prior to a drop of 1^{o}/30m in the 8 1/2" and 5 7/8" sections through the reservoir formations ending at an inclination of 17^{o}. A side view of the well can be seen in figure 4.

Wellbore tortuosity is caused by the inability to drill straight holes. Dogleg severity (DLS) and tortuosity causes bending stress on the casing and tubing, providing additional local axial stress. Bending stress can be calculated with equation 2.2

$$\sigma_b = \pm \frac{ED\pi\alpha}{360 * 100 * 12} \tag{2.2}$$

where D is the outside diameter of the pipe, E is Young's modulus and α is the DLS in degrees per 30 meters.

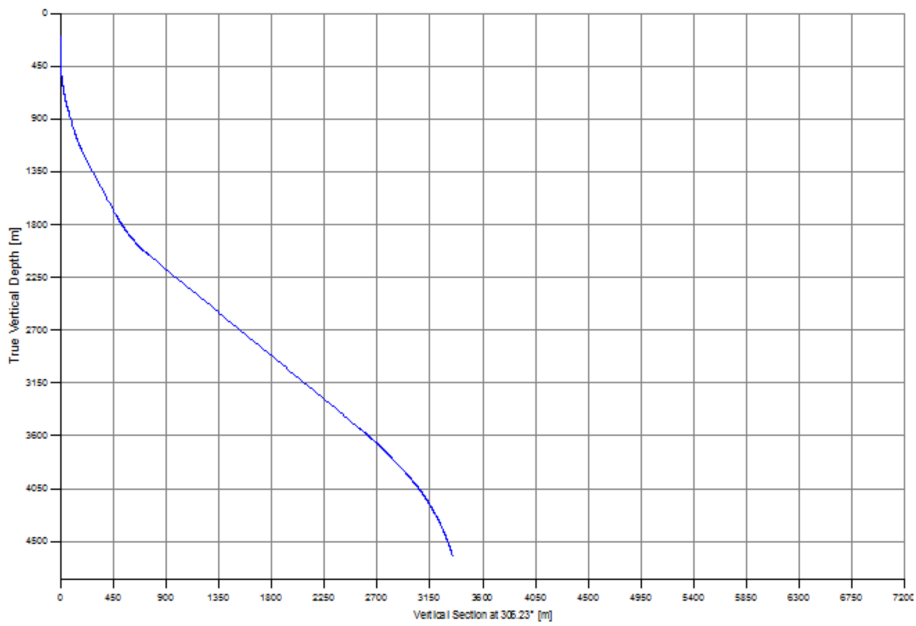

Figure 4: Side view of well X

The bending stress varies through the pipe wall from tensile on the outside of the bend, to compressional on the inside of the bend (Bellarby, 2009). To account for tortuosity WellCat^{TM} uses DLS overrides. By manually adding an additional DLS along the wellbore, the user can specify the maximum DLS that the tubing and connections will see. Bending stresses are calculated based on this DLS. The tortuosity magnitude is affected by several parameters such as formation properties, BHA, drill bit and RPM/WOB. For a well already drilled and surveyed, the actual wellpath provides the basis for calculation of bending stresses. For the planning of a well, there is a need to add DLS overrides due to the unknown actual wellpath. Bellarby (2009) suggests to add a DLS of 2-3^o/30m depending on drilling equipment and previous experience. The DLS override used on Well X is described in appendix A.2.

A conventional casing program is planned based on the need for a 5 1/2" x 4 1/2" tubing. There is, however, a need to seal off formation *One* before drilling the 5 7/8" section. This is done with a 7" liner. The 7" liner will be perforated for production after completion. For an HPHT well some operators require that induced temperature variations are included in the casing stress analysis. This requires the use of WellCat^{TM} or similar software, whereas a simpler and more user friendly software (i.e. StressCheck^{TM}) are used for non-HPHT wells. For Well X, these casing simulations has been conducted in WellCat^{TM} and the casing program is presented in Table 5.

2.3.4 Expected Interventions

Well interventions cause casing wear, which may damage the integrity of the casing. Tool joint wear, due to rotation of drill pipe, are the main source of casing wear, but interventions should also be investigated for its effect on casing wear (Shen, 2012).

Although difficult to predict, some well interventions are known in the planning phase of the well. The following well intervention operations are planned for Well X:

- Wireline logging of the reservoir sections after drilling.
- Perforation of 7" liner by wireline.

There is also a possibility for production enhancing interventions:

- Setting of plug to isolate reservoir *Two* and *Three* in case of water production from the lower reservoirs.

Table 5: Casing and tubing scheme.

Name	OD	Top [MD]	Base [MD]	Grade	Weight
Conductor casing	30"	24	338	X-56	457,0
Surface casing	20"	24	1 278	P-110	133,0
Intermediate casing	14"	24	1 470	SM125S	114,0
	13 5/8"	1 470	4 347	SM125S	88,2
Production casing	10 3/4"	24	1 024	SM125S	91,2
	9 7/8"	1 028	5 146	SM125S	66,4
Production liner	7"	4 914	5 518	S13CrS110	35,0
Production tubing	5 1/2"	24	4 800	S13CrS110	26,0
	4 1/2"	4 800	5 068	S13CrS110	17,0

- Scale and sand removal with coiled tubing.

2.4 Well integrity and software challenges

Well integrity is the presence of well barriers at all times to prevent an uncontrolled flow of fluid from the well to the environment. The NORSOK D-010 standard requires two barriers, at all times, between the surface and an overpressured hydrocarbon bearing formation (NORSOK D-010, 2004).

For a well in production, both the production casing and the production tubing act as well barriers. It is therefore important that the drilling engineer runs simulations on the conditions the tubing and casing may see during the lifespan of the well. Simulation of operations and conditions defines the maximum pressure that the casing and tubing must be able to withstand. This is the basis for the pressure tests conducted after installation. A pressure test is the only way to verify the integrity of a barrier, once installed.

The industry standard software for integrity verification of casing and tubing for HPHT wells is WellCat™. WellCat™ is part of the Landmark EDM software package which is commonly used by drilling engineers.

WellCat^{TM} consists of five modules. Two modules are for load generation: Drilling mode and production mode. Drilling mode allows the user to simulate fluid flow, temperature and heat transfer during drilling. Likewise is Production mode used to simulate fluid flow and heat transfer during completion, testing and production operations.

Results from drilling and production modules are basis for stress analysis of casing and tubing. These are done in the casing module and tubing module. The casing and tubing module allows the user to simulate casing and tubing loads under fluid pressure, thermal loading and under influence of mechanical forces. The load cases defined in drilling and production modules are linked to the casing/tubing module for review of the casing design integrity.

In addition to the four modules described above, WellCat^{TM} has a multistring module for modelling of annulus pressure build-up and wellhead growth (WellCat User Manual, 2006).

3 Forces and Loads

3.1 Material properties

Casing, tubing, drill pipe and other equipment are chosen based on the expected forces it will be exposed to. Reviewing of the mechanical properties of the material is done to ensure the equipment can stand the expected forces. Material failure can affect the safety of operations as well as being a costly affair. Most material failures can be avoided by using the right material and proper design.

Material properties is, somehow unconventionally, presented in Figure 5 (Budinski, 2002). The chemical and physical properties (with the exception of thermal conductivity and thermal expansion) are usually not relevant to a drilling engineer and they will therefore not be discussed in detail here. Procurement and manufacturing considerations are not a material property in the same way as the other three categories. However, the availability of material in the different shapes, sizes, grades etc. can be an important selection factor (Budinski, 2002).

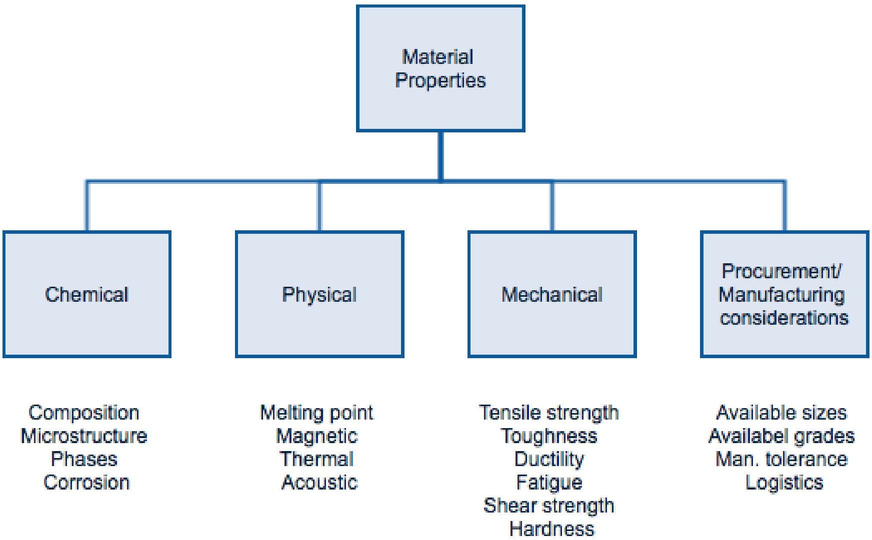

Figure 5: Material properties for metals. Modified (Budinski, 2002)

Mechanical properties of the material are important to an engineer deciding on which material to use. Mechanical properties decide how a material responds to exerted force. External forces induce stress in the material. For a pipe (tubing and casing) stresses can act axially in the form of tension and compression and it can act radially in the form of burst and collapse. Stress (σ) is defined as force (F) per unit area (A):

$$\sigma = \frac{F}{A} \tag{3.1}$$

If the stresses are sufficiently large, they will cause either elastic (non-permanent) or plastic (permanent) strain. Strain is defined as the fractional length change of the material and may be written as:

$$\varepsilon = \frac{\delta}{L} \tag{3.2}$$

where L is the original length and δ is the change in length caused by stress. The relationship between stress and strain is defined in Hooke's law:

$$\sigma = E\varepsilon \tag{3.3}$$

where E is a constant of proportionality referred to as *Young's modulus* or *modulus of elasticity* (Timoshenko and Goodier, 1970). A typical stress-strain relationship is presented in Figure 6. The straight line assumption for the plastic deformation area is an approximation. The slope of the curve in this region is the modulus of elasticity. The modulus of elasticity is temperature dependent and reduces with increased temperature (Bellarby, 2009).

The point where the deformation of the material goes from elastic to plastic is called the *elastic limit* or *yield point.* Although the elastic limit and yield point are not the same, for most materials they are difficult to separate. A common way of determining the yield point of a metal is to measure the yield strength at a 0.2% offset strain (Budinski, 2002). Yield strength is measured in pounds per square inch or Pascal. Figure 6 shows how a tensile test is conducted and how the stress-strain graph develops during the test.

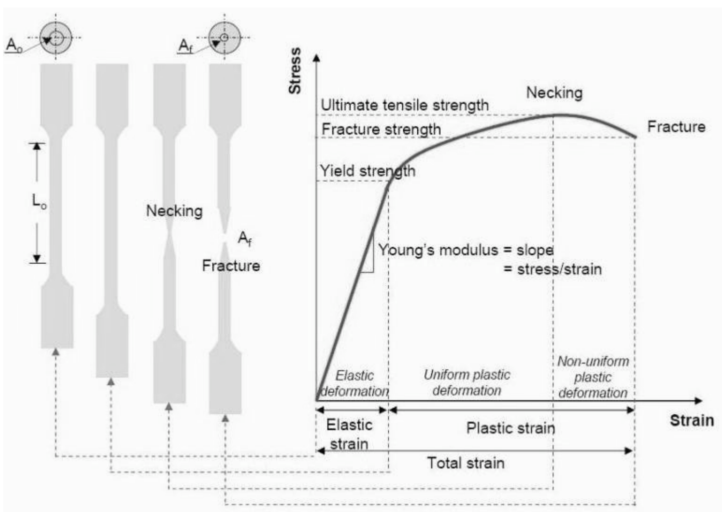

Figure 6: Tensile test and stress-strain relationship (Shah, K.P., 2009)

Figure 7 shows how three different grades of material develop under stress. Note the large difference in yield stress compared to the difference in ultimate tensile strength (UTS). The large difference in UTS and yield stress for K-55 in the graph below, allows it to be used as expandable tubulars (Kaiser, 2005).

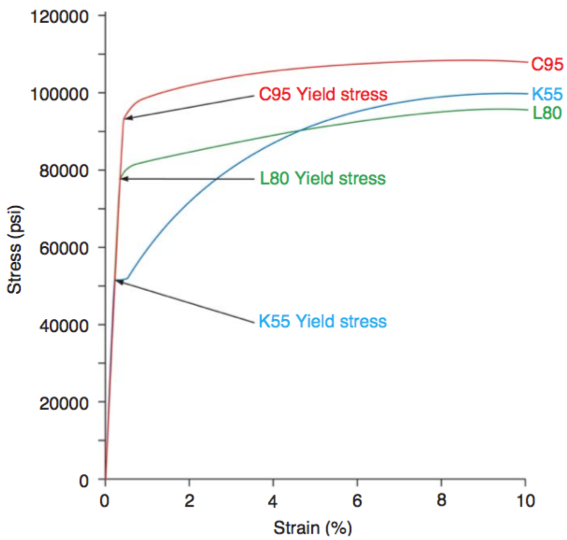

Figure 7: Stress-strain relationship (Bellarby, 2009)

Alloys are used in order to achieve the desired material strength. Alloys are metals combined with one or more other elements in a process called solid solution strengthening. In the oil industry carbon steels are the most common alloy used. Carbon steel is iron with carbon as the major strengthening element (Budinski, 2002).

3.2 Axial forces

Axial forces are forces working in the length direction of the tubing (or casing). Tensile forces are positive and compressional forces are negative. Considering free hanging tubing in a vertical well with no fluid, the axial load is the average weight (per length unit) multiplied with the length of the tubing. The maximum axial load will be at the surface, and decreasing linearly towards zero at the bottom of the tubing.

Piston forces

It is common to use a buoyancy factor to evaluate the effect of buoyancy in a well. For tubing stress analysis it is convenient to view the buoyancy effect as a piston force acting on the bottom of the tubing. Piston forces are forces caused by fluid pressure acting on an exposed cross-section of the tubing (Bellarby, 2009). Such areas can be a crossover (or change in inner diameter) or an expansion device (PBR, expansion joint). The buoyancy force is compressional and thus has a negative prefix. For an expansion device the stresses caused by piston forces on exposed area can have greater impact on the tubing design than the stress relief from expanding. The stresses can be calculated knowing the inner and outer diameters of the expansion devices as well as the inner and outer pressures.

Pressure testing

Pressure testing against a set plug is another source of axial tension. Assuming the fluid inside the pipe and in the annulus is the same, the pressure exerted on the plug would be the same as the applied surface pressure. The generated force on the tubing would then be:

$$F_p = \Delta p_{plug} A_i \tag{3.4}$$

By application of Hooke's law, the free elongation of the tubing can be found from equation 3.5:

$$\Delta L_p = \frac{L \Delta p_{plug} A_i}{E(A_o - A_i)} \tag{3.5}$$

where L is the original length of the pipe, A_i is the internal area of the tubing and A_o is the outer area of the tubing.

Ballooning

Radial strain and axial strain are affecting each other and the relationship between them is defined by *Poisson's ratio*, μ:

$$\mu = -\frac{Radial\ strain}{Axial\ strain} \tag{3.6}$$

This means that applied pressure to the inside of the tubing will, in addition to axial stress from differential pressure across the plug, cause axial tension from ballooning. The ballooning force can be calculated using the Poisson's ratio (equation 3.7) and by using Hooke's law again, the pipe elongation can be calculated (equation 3.8):

$$F_b = 2\mu(A_i \Delta p_i - A_o \Delta p_o) \tag{3.7}$$

$$\Delta L_b = \frac{-2\mu L}{E(A_o - A_i)}(A_i \Delta p_i - A_o \Delta p_o) \tag{3.8}$$

Buckling
Free motion of the tubing is often prevented by the presence of a production packer. Forces created in the above mentioned events are then transferred through the packer onto the casing. When the tubing is locked in place with a production packer, induced forces cause buckling of the tubing (Lubinski and Althouse, 1962).

Buckling is an important factor when considering tubing stresses and occurs when the pressure inside the casing is greater than on the outside. The presence of bends in the tubing means that tubing can buckle even without being in compression. When a bend is present in the pipe, the internal pressure will have a greater area to work on the outer bend than the inner. This causes a sideway force which encourages more bending. Compression and internal pressure encourage buckling, while tension and external pressure prevents buckling (Bellarby, 2009).

Dawson (1984) calculated the critical buckling force for a deviated well:

$$F_c = \sqrt{\frac{4EIwsin\theta}{r}} \tag{3.9}$$

for sinusoidal buckling and

$$F_c = 1,41 \sim 1,83\sqrt{\frac{4EIwsin\theta}{r}} \tag{3.10}$$

for helical buckling, where F_c is the critical compressive load, w is the buoyed weight of the pipe, θ is the hole inclination, r is the radial clearance between the tubing and borehole and I is the moment of inertia. I is given by:

$$I = \frac{\pi}{64}(D_o^4 - D_i^4) \tag{3.11}$$

where D_i and D_o is the inner and outer diameter of the pipe.

Thermal expansion/compression
The temperature in the well changes with different operations (production, shut-in etc.). These temperature changes cause the tubing to expand or contract and this induces axial forces on the tubing. The length change per temperature change is given by:

$$\Delta L_T = C_T \Delta T L \tag{3.12}$$

and the force created if the tubing is locked in place in both ends is given by:

$$F_T = -C_T E \Delta T (A_o - A_i) \tag{3.13}$$

3.3 Burst

The maximum burst pressure, P_B, for a pipe, as given by ISO 10400 (ISO TR 10400), is shown in equation 3.14:

$$P_B = \frac{2 k_{dr} t_{dr} f_u}{D_o - t_{dr}} \tag{3.14}$$

where

$$t_{dr} = t_{min} - k_a a \tag{3.15}$$

$$k_{dr} = \left(\frac{1}{2}\right)^{1+n} + \left(\frac{1}{3}\right)^{1+n} \tag{3.16}$$

and

- n is the material dependent dimensionless hardening constant and should be determined experimentally[1].
- a is the maximum depth of cracks that can be expected in the pipe.
- t_{min} is the pipe wall thickness excluding imperfections such as cracks.
- f_u is the tensile strength of the material.
- k_a is the burst strength factor.

[1] n=0,1693-0.000812 × yield strength [ksi] (ISO TR 10400)

Burst strength factor, k_a, varies with pipe material and an k_a of 2,0 should be used if it is not determined for the selected pipe material. k_a is 1,0 for 13Cr products (ISO TR 10400).

For simplicity, Barlow's formula can also be used for determining burst pressure rating of a pipe. Barlow's formula provides a relationship between internal pressure (P), stress (S_c), wall thickness (t), and outer diameter (D) (Hauk, 1963).

$$S_c = \frac{D}{2t}P \tag{3.17}$$

By substituting S_c with the minimum yield strength of the casing, adding a tolerance factor for correction of wall thickness and solving for P, the following equation is achieved:

$$P_B = Tol \left(\frac{2Y_p t}{D}\right) \tag{3.18}$$

The tolerance factor depends on the quality of the delivered pipe and varies between operating companies, but the normal tolerance factor is 0.875 which indicates a possibility of 12,5% wall thickness reduction (Bellarby, 2009). The uncertainty of wall thickness can be reduced by performing pipe inspections and if the true wall thickness can be used, a tolerance factor of 1,00 can be used (Burres et al., 1998).

Barlow's equation suggests a linear reduction of burst pressure with wall thickness. This illustrates the importance of estimating the casing wear and corrosion as a 30% reduction in wall thickness equals a 30% reduction in burst pressure rating.

3.4 Collapse

Pipe collapse is divided into four modes: yield, plastic, transitional and elastic. The pipe material and pipe slenderness (the D/t ratio) decides which collapse mode that will occur. ISO 10400 defines one empirical equation for each collapse mode:

$$P_{yield} = 2f_{ymn}\left[\frac{D/t - 1}{(D/t)^2}\right] \tag{3.19}$$

$$P_{plastic} = f_{ymn}\left[\frac{A_c}{D/t} - B_c\right] - C_c \tag{3.20}$$

$$P_{transitional} = f_{ymn}\left[\frac{F_c}{D/t} - G_c\right] \tag{3.21}$$

$$P_{elastic} = \frac{46,95 \times 10^6}{(D/t)[D/t - 1]^2} \tag{3.22}$$

A_c, B_c, C_c, F_c and G_c are empirical constants decided for each pipe material through earlier experiments. f_{ymn} is the minimum yield strength of the material (Y_p).

Equations 3.19 through 3.22 are considered over-conservative for D/t-ratios of 21-24, but risk is higher for D/t-ratios of 11-15 (Adams et al., 2001).

Figure 8 illustrates how the slenderness of the pipe affects what kind of collapse that will occur. The figure is valid for one specific grade, and other materials will have different curves.

Other factors that affect pipe collapse strength are ovality, eccentricity and residual stress, but these effects are not evaluated in the equations presented in ISO 10400.

3.5 Triaxial

Tubing and casing is rarely exerted to only one kind of stress. Stress on a cylinder are divided into axial stress (σ_a), tangetial stress (σ_t) and radial stress (σ_r). The radial and tangential stresses are caused by differential pressure over the pipe wall. Triaxial analysis evaluates the influence of axial stress on the tangential and radial stress. Barlow's formula (equation 3.17) which is commonly used for burst calculations does not take in the effect of axial stress. Neglecting the effect of axial load could introduce large errors in the pipe design, and have negative effect on the integrity of the pipe (Aasen and Aadnøy, 2003).

The casing and tubing are subjected to axial loads and bending causing axial tensile or compressive stress. The inside and outside pressure on the pipe causes radial and tangential (or hoop) stress. By using the von Mises distortion energy theorem, the three forces are combined into one, σ_{VME} (Bourgoyne et al., 1991):

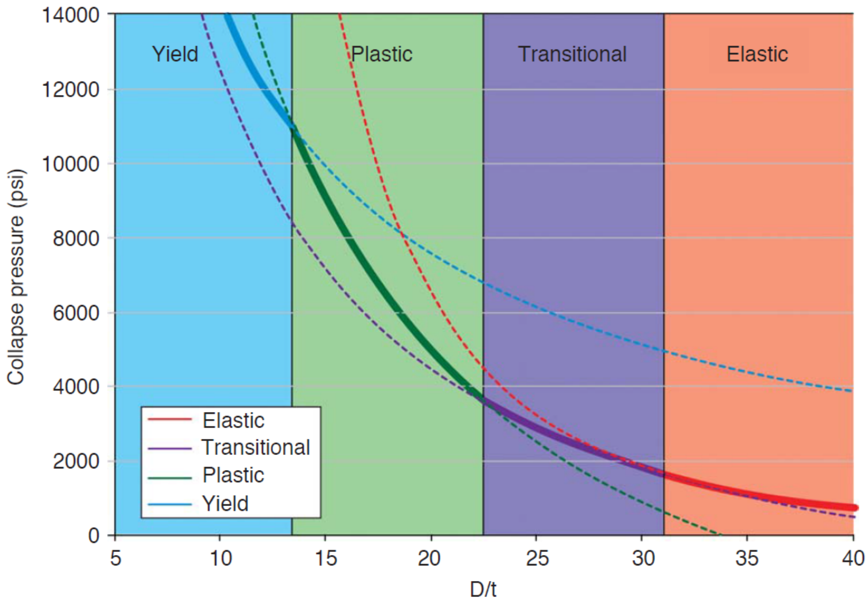

Figure 8: Collapse pressure as function of D/t (Bellarby, 2009).

$$\sigma_{VME} = \frac{1}{\sqrt{2}}[(\sigma_a - \sigma_t)^2 + (\sigma_t - \sigma_r)^2 + (\sigma_r - \sigma_a)]^{0,5} \tag{3.23}$$

where

$$\sigma_r = \frac{p_i A_i - p_o A_o}{(A_o - A_i)} - \frac{(p_i - p_o) A_i A_o}{(A_o - A_i) A} \tag{3.24}$$

and

$$\sigma_t = \frac{p_i A_i - p_o A_o}{(A_o - A_i)} + \frac{(p_i - p_o) A_i A_o}{(A_o - A_i) A} \tag{3.25}$$

The axial stress, σ_a has to be calculated using the equations from subsection 3.2. The von Mises equivalent (VME) stress always has the highest value, either on the outside or the inside of the casing, so it is only necessary to calculate the radial and tangential stress for these two points.

Aasen et al. (2003) defines the design factor as the yield strength of the pipe divided by the von Mises stress:

$$DF = \frac{\sqrt{2}\sigma_y}{\sqrt{(\sigma_a - \sigma_t)^2 + (\sigma_t - \sigma_r)^2 + (\sigma_r - \sigma_a}} \tag{3.26}$$

When deciding on design factors to use for a casing or tubing design there are links between the burst design factor and the triaxial design factor. ISO 10440 recommends that casing and tubing are not pressure tested to more than 80% of its nominal rating. In addition the wall thickness uncertainty is 12.5%. Taking these points into consideration the burst design factor is calculated:

$$\text{Burst DF} = \frac{0,875 \times \text{Nominal rating}}{0,8 \times \text{Nominal rating}} = 1,094 \approx 1,10 \tag{3.27}$$

The triaxial design factor can then be found by removing the 12,5% wall thickness allowance:

$$\text{Triaxial DF} = \frac{1,094}{0,875} = 1,25 \tag{3.28}$$

If the pipe used is inspected to reduce the wall thickness allowance, the design factors can be changed accordingly. The triaxial analysis is considered less conservative than the burst and collapse analysis so the design factor should therefore be higher (Bellarby, 2009).

3.6 Packer forces

The production packer serves two purposes. It anchors the tubing to the casing wall, thus restricting upwards and downwards movement of the tubing string, and it serves as an annular seal separating the well fluid and annulus fluid (Bellarby, 2009). The presence of a packer greatly influences the axial loads in the tubing. By restricting movement, all elongation or contraction of the tubing string due to heating, ballooning etc. is transferred into axial loads.

The packer setting process influences the tubing analysis as all axial stress present in the tubing, when the packer is set, is locked in. For Well X the packer is set hydraulically, meaning that pressure is applied from the surface down the tubing against a plug set in the tailpipe. This pressure against the plug creates an axial load (elongation of tubing) that is locked in when the packer sets. These stresses then affect all subsequent calculations. The presence of a cross-over further enhance the axial forces as it contributes to a downward piston force (ref: subsection 3.2).

The production packer may see high differential pressures during the life of a well. These have to be simulated in order to assure the packer can handle them. Figure 9 shows an example of the operational condition one specific packer can endure. By simply plotting the results of the simulations in same plot, it is easy to see if they are within the packer's ability.

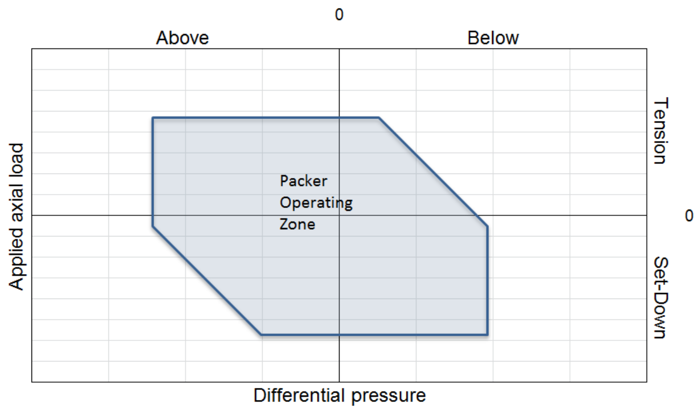

Figure 9: Production packer envelope.

3.7 Connections

The connections have to endure the same loads as the rest of the casing/tubing. Despite this, many connections are prone to failure under compressive loads. Compression can lead to a damaged torque shoulder which again can damage the radial seal face and leakage (Bellarby, 2009). There are four classes of connections (I-IV) where IV has the highest strength rating (ISO TR 13679). Connections are not tested to failure, but they are tested to check that the manufacturer's claims are valid. Connection failures are seldom catastrophic, as they remain their structural integrity even though a leakage develops. This allows for use of design factors as low as 1,00 in some cases (Bellarby, 2009).

4 Casing wear and temperature deration

4.1 Casing wear

As subsection 3.3 illustrates, there is a direct connection between burst strength of pipe and wall thickness. Casing wear reduces the wall thickness by galling and polishing between the drillstring tooljoints and the casing wall. Casing wear has become an increased problem in deep wells, because of high doglegs and large tension in the drillstring. These factors combine, creating large lateral loads on the points where the drillpipe contacts the casing (Hall et al., 1994).

The causes of casing wear were investigated by Fontenot and Bradley (1975). They compared wear from pipe rotation, tripping and wireline running and concluded that the major cause of casing wear is drillstring rotation. They identified six parameters that had importance for wear (Fontenot and Bradley, 1975):

- Rotating time and speed
- Mud abrasiveness
- Drillpipe wearing capability
- Casing wear resistance
- Dogleg severity
- Tension in drillstring

Through laboratory testing a mathematical model for casing wear estimation has been developed (Hall et al., 1994). According to the model, the volume of material removed is the product of a wear factor, the normal force per foot and sliding distance. The assumption behind the model is that the volume of material removed (V) is proportional to the frictional work done (W):

$$V = \frac{W}{E} \tag{4.1}$$

where E is the energy needed to remove one cubic inch of steel (specific energy). The frictional work per foot is a product of the friction factor (μ), the normal force (F_N) and the sliding distance. Then the equation 4.1 becomes:

$$V = \frac{\mu \times F_N \times S}{E} \tag{4.2}$$

By combining friction factor and specific energy to a wear factor (WF), the equation reduces to:

$$V = WF \times F_N \times S \tag{4.3}$$

The wear factor unit is square inches per pound foot and is commonly reported in E-10 due to its small size. S is given as:

$$S = \text{Drilling distance} \times \pi \times RPM \frac{D_{TJ} L_{TJ}}{ROP \times L_{DP}} \tag{4.4}$$

The experiments carried out by Hall et al. (1994) resulted in equation 4.3 which the casing wear software DrillNET CasingWear$^{\text{TM}}$ is based on (Chu, 2010). The software uses data about wellpath geometry, drill string configuration and several operational parameters from drilling to calculate the total volume removed per foot. The wear factor has to be manually added to the program, and this is often based on previous experience, or in some cases guessed. The input parameters are discussed further in appendix B.1.

The casing wear model by Hall et al. suggests that the total wear volume increases linearly with time. Hall and Malloy (2005) investigated the relationship. They defined a work function:

$$\psi = F_N \times S \tag{4.5}$$

thus,

$$V = WF \times \psi \tag{4.6}$$

This implies a linear relationship between wear factor and total wear volume. When plotting the wear volume against the work function, it did not correspond to a linear relationship as shown in Figure 10. Instead curve fitting gave a new function for wear volume:

$$V = A \times (1 - e^{(-B \times \psi^c)}) \tag{4.7}$$

where A, B and C are constants. The total wear volume reaches a limiting factor as the work function increases. This limiting value is equal to the constant A. As the wear volume reaches its maximum, so do the wear groove depth. These results led to the introduction of contact pressure threshold (CPT). As the wear groove grows, the contact area between the tooljoint and casing wall increases. This leads to a lower contact pressure as the same weight is spread over a larger

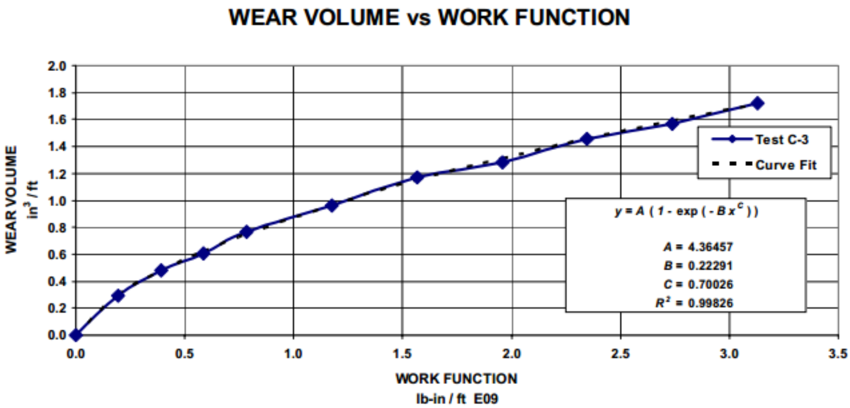

Figure 10: Wear volume as function of work (Hall, 2005).

area thus reducing further wear. The CPT can then be used to calculate the maximum wear groove depth and by that predicting the time until maximum wear volume is reached (Hall, 2005). For further reading on casing wear theory, the reader is referred to Kjellevoll (2013).

4.2 Temperature derating

The strength of alloys is affected by temperature. An increase in temperature of 110 degrees can reduce the strength of the material by 5 to 10 % (Payne and Hurst, 1986). This is an important consideration for a drilling engineer planning an HPHT well. With reservoir temperatures of 170^o the well will be heated during production thus reducing the strength of the tubing. Wellcat^{TM} has a built in function for default and calculates a reduction in yield strength of $0.03\%/^oF$ starting from 70^oF (WellCat User Manual, 2006). However, as figure 11 shows, this can be non-conservative for some steel grades. Specific temperature deration factors should therefore be used to get correct simulations. Appendix A.1 discusses how the software handles temperature deration for different steel grades.

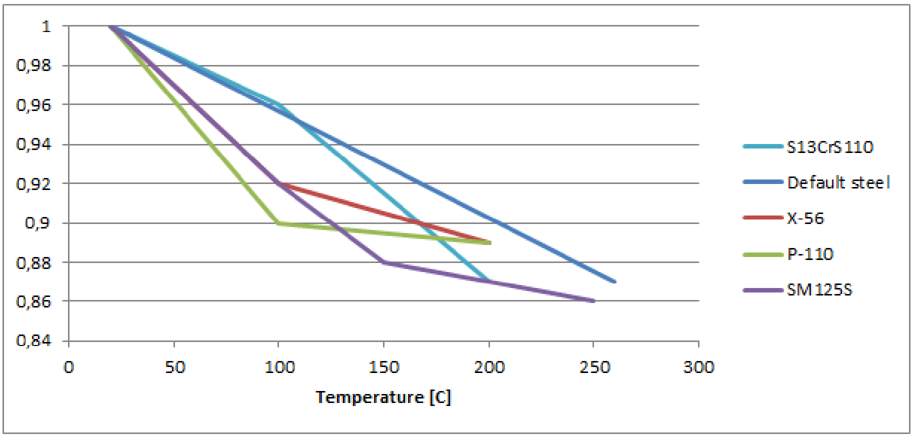

Figure 11: Temperature deration.

5 Tubing Stress Analysis

In this section the author goes through tubing stress analysis for a suggested completion in order to verify whether or not it can stand the subjected loads during the well life. The purpose is not to find the optimal completion for the well, but to investigate the work process and methods of the integrity verification. The tubing stress analysis is described in detail in appendix A.

5.1 Work process

The work process for tubing stress analysis can be divided into five steps. These steps are illustrated in figure 12. The drilling engineer responsible for tubing design, has to go through all steps in order to ensure the design chosen is suited for the well. In the next subsections the extent of each step is described.

Figure 12: Tubing analysis work process.

5.1.1 Identify requirements

There are several requirements for wells drilled on the NCS. Having an overview of the valid requirements can be difficult, and significant effort is put down by the operator companies to simplify the amount of information a drilling engineer has to relate to. International standards such as the ISO (International Organization for Standardization), API (American Petroleum Institute) and CEN (European Committee for Standardization) are used in most parts of the world. They contain requirements for both equipment and operations and form the basis for more specific standards.

Local conditions, such as the harsh conditions on the NSC, require more specified requirements. The NORSOK standard supplements the international standards to define requirements for well operations on the NCS.

In addition to local or national requirements, each company may have its own set of requirements for specific operations. Often they cover, in detail, what precautions that have to be made before an operation can be carried out. In the case of tubing design, this might be what design parameters to be used in simulations and what kind of loads or operations that has to be simulated.

Before a drilling engineer can analyze a tubing design, it is essential to know what requirements that is valid for the well. This may vary for the purpose of the well (producer or injector), its location (subsea or platform well) and its pressure and temperature regime.

5.1.2 Information gathering

After technical requirements have been identified, information needed to carry out simulations has to be collected. Figure 13 summarizes the most important information needed for WellCat^{TM}simulations. Identifying and locating this information can prove to be difficult as it is a collection of data from several departments (geologists, reservoir engineers, completion engineers, suppliers and colleagues).

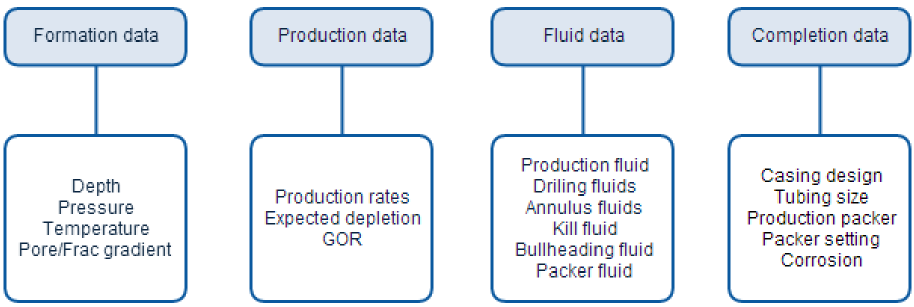

Figure 13: Technical information for tubing simulations.

5.1.3 Model set-up

The WellCat^{TM} model can be built after the information has been gathered. The initial condition is the basis for the other simulations. It is therefore of high importance that the initial conditions are correctly defined. This includes defining the casing design (including annulus fluids) and tubing design as well as tubing and annulus pressure and temperature gradients. Any mistakes in the initial conditions will reproduce itself in the simulations, giving incorrect results.

The production operations and load cases are built on the initial conditions. The production operations are used to simulate pressure, temperature and flow development in the well and serves as input for the load simulations. The model is described further in subsection 5.2.

5.1.4 Run simulations

When production operations have been defined, calculations in the production module of the software can be run. This produces temperature, pressure and flow profiles for the operations predefined by the user. Production simulations should be carried out for producing, shut-in and injection scenarios, as they will create different temperature and pressure regimes.

The load simulations follow the production simulations. The tube-module in the software is used to calculate stresses induced in the tubing during different scenarios the well may see during its life. Several load cases are directly linked with the results from the production simulations. The simulations are explained in detail in appendix A.4.

5.1.5 Evaluate results

WellCat^{TM} presents the results from the simulations in several different ways. Each load case can be evaluated separately or they can be evaluated together. Graphical presentations of absolute safety factors for burst, collapse, axial and triaxial stress are presented, and gives a clear answer to whether or not the tubing are able to handle the stresses. An example of this can be seen in figure 16 in subsection 5.3.1.

5.2 Tubing stress modelling

5.2.1 WellCat^{TM} software

The WellCat^{TM} software has an inventory function for both pipes (drillpipe and casing) and fluids. The tubular inventory is pre-defined and pipes are listed with weight, grade and load ratings used for the stress calculations. The inventory does not specify whether or not these load ratings include a supplier safety factor. The software allows for creation of software templates to restrict available inventory. This allows for creation of region- or project- specific inventories based on availability and logistics or other factors.

The fluid inventory has to be specified by the user and all fluids, from drilling muds to hydrocarbons, to be used in simulations has to be defined in the inventory. As WellCat^{TM} is not the preferred software for hydraulic simulations, fluid parameters for muds and annular fluids are not of the highest importance. The thermal properties are however, important for wellbore temperature calculations and the mud weight is vital for pressure calculations.

Hydrocarbons can be defined as either a vapor-liquid equilibrium (VLE) or a standard hydrocarbon. For a gas fluid with heavy components, as is the case for Well X, it is recommended by the software to use the VLE setting. However, this setting prevents the user from determining a desired gas-oil ratio (GOR) when defining the production operations. The software uses the Peng-Robinson equation of state to calculate a GOR based on the user-defined oil production rate (WellCat User Manual, 2006). This property of the VLE setting prevents the simulation of different gas rates that occur during the production lifespan of a well. In order to do production simulations with different GOR the VLE setting cannot be used and the fluid has to be defined as a standard hydrocarbon.

5.2.2 Building model frame

The WellCat^{TM} model is built with the set-up described in subsection 2.3. The production data is provided in table 6. WellCats^{TM} inability to model production from different pressure zones requires the user to choose *one* production zone. In the case of Well X production from reservoir *three* should be modelled as this zone is the source of the highest pressures and temperatures during operations. This is a conservative estimate as production from reservoir *three* only, is unlikely. If this reservoir proves to contain hydrocarbons it will be co-produced with reservoir *one* and possibly reservoir *two*. This will reduce the resulting temperature, thus reducing forces on tubing and casing.

The well is suggested completed with tapered tubing. A 5 1/2" tubing is preferred to limit the pressure loss during production, but the limited clearance in the 7" liner requires the use of 4 1/2" tubing in the bottom of the tubing string. The cross-over is placed at 4 800 MD with the base of the tubing reaching to 5

068 MD. The completion is presented in table 7 and figure 14.

The production packer is set at 5 050 MD. As explained in subsection 3.6 the packer is set hydraulically against a plug in the tailpipe. The packer will set when the applied surface pressure reaches 157 bar.

Table 6: Production data.

Key data	**Early life**	**Steady state**	**Late life**
Gas [Mm^3/day]	4 500	4 500	250
Oil [m^3/day]	1 700	1 500	50
Water [m^3/day]	0	5	100
Reservoir pressure [bar]	865	830	750

Table 7: Tubing specifications.

Size [in]	**Grade**	**Weight [lbf]**	**Depth [MD]**
5 1/2	S13CrS110	26,00	24 - 4 800
4 1/2	S13CrS110	17,00	4 800 - 5 068

5.2.3 Production operations and load cases

WellCat^{TM} requires a series of production operations to be defined in order to carry out load case simulations on the well. The production operations produce temperature, pressure and fluid flow profiles for the well during different production scenarios defined by the user.

Fluid properties, pressures and flow rates highly affect the temperature profiles created. Ensuring correct values for these parameters are important for the integrity of the simulation (Bellarby, 2009). These profiles form the basis for the tubing stress analysis in the program. The software has the ability to simulate temperature for either a finite time period or a steady state production scenario (WellCat User Manual, 2006).

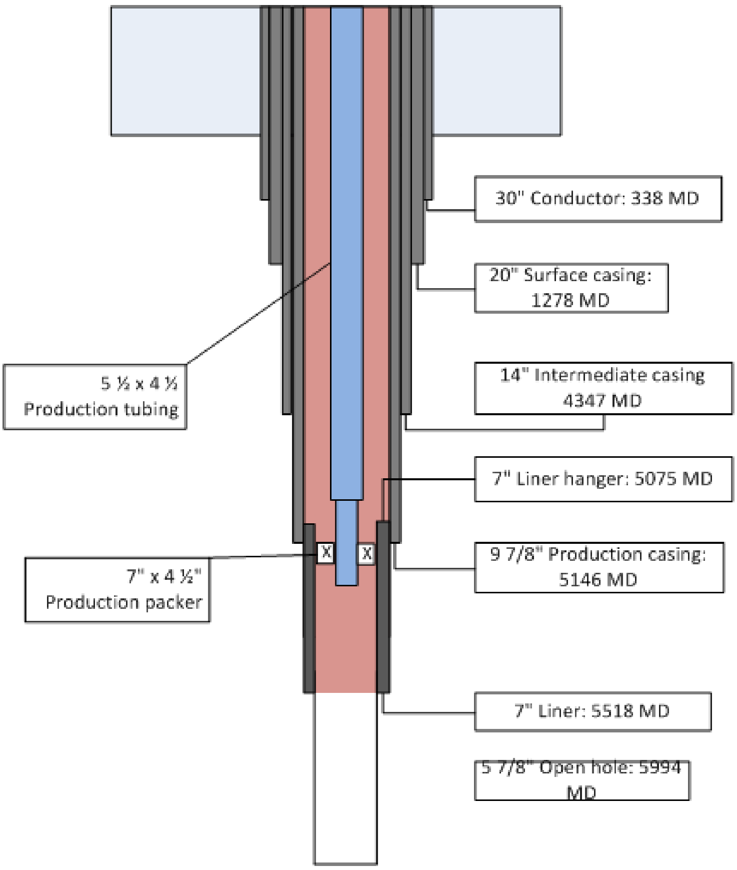

Figure 14: Well schematic.

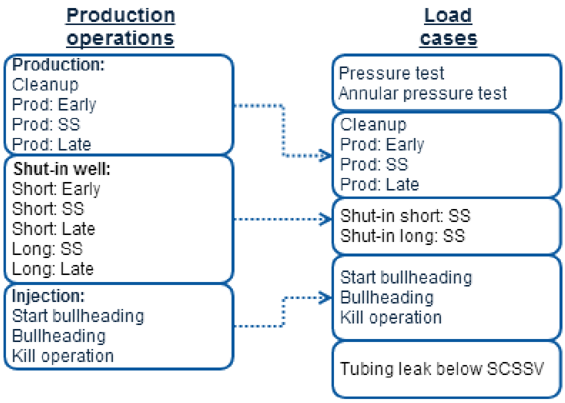

Figure 15: Production operations and tubing load cases.

Which load cases to be run at the tubing design are often decided by company policy. When defining load cases in the WellCat^{TM} software they can either be linked to the related production operation or they can be manually defined by the user.

The production operations, load cases and how they are linked is shown in figure 15. Detailed information and explanation of the production operations and load cases are provided in appendix A.3.

5.3 Results

A brief summary of the results from the tubing stress analysis is presented in this subsection. A more in-depth description of the results is presented in appendix A.5 and A.6.

5.3.1 Tubing results

Well X, being an HPHT well, is subject to large pressures and high temperatures. The tubing strength requirements are thus higher than for a normal well. By plotting the absolute safety factors against well depth, it is possible to see if the tubing can hold the loads it is subjected to. As shown in figure 16 the axial safety factor is compromised by several load cases (red circle). As the figure shows, the safety factor is compromised below the cross-over at 4 800 MD. The 4 1/2" tubing cannot stand the axial loads it is subjected to. The same is true for the triaxial safety factor. The absolute safety factors for each operation is presented in table 8.

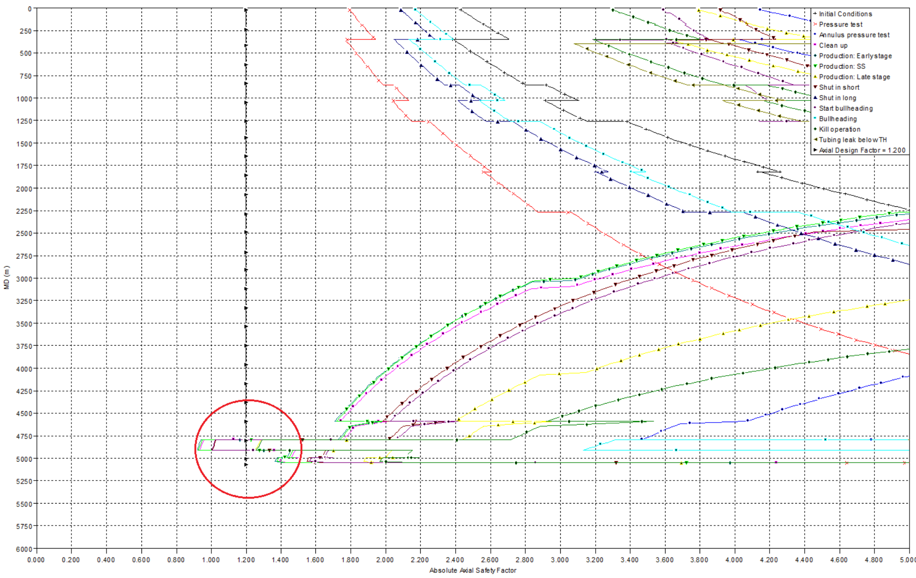

Figure 16: Axial safety factor (WellCat).

The burst and collapse safety factors are well above the required design factors of 1.10 and do not represent a problem.

5.3.2 Production packer results

An overview of the packer loads relative to packer limitations is found by plotting loads for the designated packer in its operating envelope. The software allows for definition of the operating envelope and presents the results as seen in figure 17. Casing wear in the production packer setting area are not included in these simulations. Wear of approximately 10 percent is expected in this case (see

Table 8: Tubing safety factors. Red number indicates design factor compromise.

	Absolute safety factor			
Load	**Triaxial**	**Axial**	**Burst**	**Collapse**
Pressure test	1.52	1.77	1.39	10+
Annulus pressure test	1.61	3.47	10+	1.63
Cleanup	0.98	0.94	3.41	10+
Prod: Early life	0.96	0.92	3.40	10+
Prod: Steady state	0.97	0.93	3.55	10+
Prod: Late life	1.28	1.25	2.65	10+
Shut-in short	0.98	1.01	1.58	10+
Shut-in long	1.95	2.05	1.76	10+
Start bullheading	0.94	1.01	1.44	10+
Bullheading	1.65	2.14	1.78	10+
Kill operation	1.14	1.26	2.03	10+
Tubing leak	1.52	3.08	10+	1.57

section 6). This will increase the area of which the differential pressure across the packer work thus increasing the force on the packer. The software does not include casing wear in these simulations.

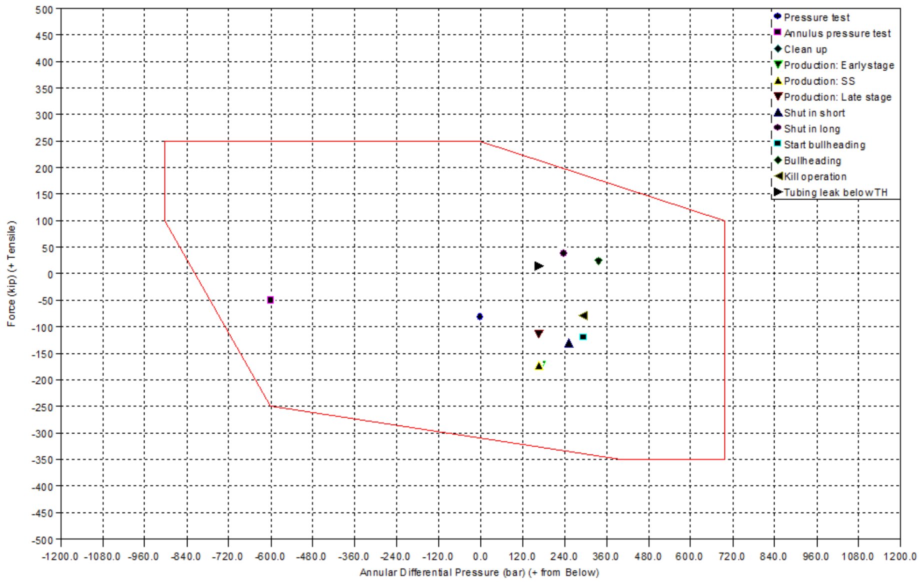

Figure 17: Production packer loads (WellCat).

As the figure shows, the operational loads are well within the limits of the packer. In depth analysis of each load case and its effect on the packer can be done by looking at the pressures and axial tubing loads above and below the packer. A more detailed presentation of the packer simulation results is presented in appendix A.6.

5.3.3 Evaluation of results

The high downhole temperature causes a reduction in material strength of approximately 10 percent (ref: figure 32, subsection 4.2) in addition to inducing thermal expansion. The thermal expansion compresses the tubing string, causing large axial stress. This axial stress is combined with the axial stress from the piston force created by the cross-over and together they give a severe compressional load on the tubing. When the differential pressure then increases, the axial and triaxial safety factors are compromised.

The easy way of reducing this problem would be to remove the 4 1/2" tubing and replace it with 5 1/2" tubing. This would remove the piston effect from the cross-over, thus reducing the compression of the string. As figure 18 shows, there are a significant addition in compressional load from the cross-over at 4 800 MD.

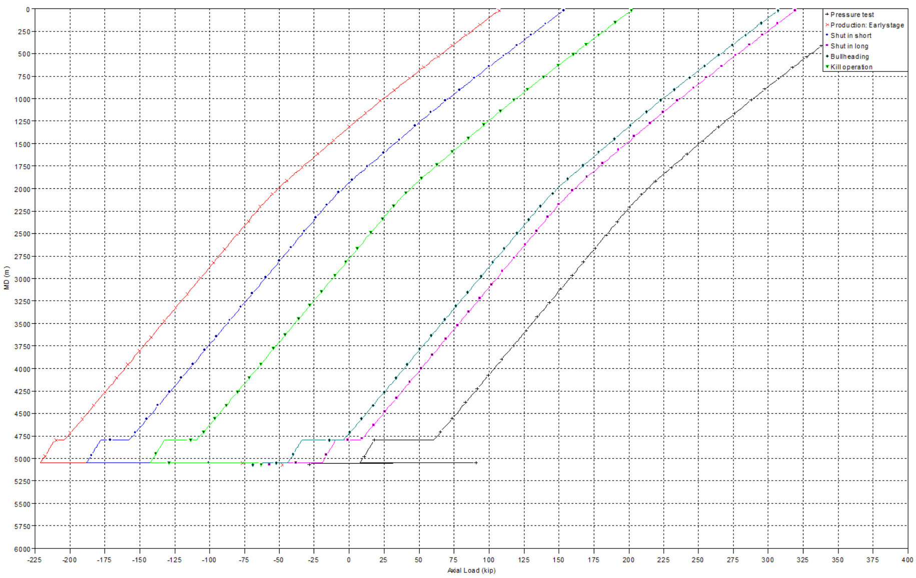

Figure 18: Axial loads (WellCat).

6 Analysis of Casing Wear

In this section, a casing wear analysis is conducted on Well X. Casing wear analysis is important to ensure the casing integrity is kept at all times, as the casing serves as a well barrier through the full life time of the well. As with section 5 about tubing stress analysis, the main purpose of this section is to investigate the work process of casing wear analysis.

6.1 Work process

The work process for casing wear analysis consists of mainly the same elements as the tubing stress analysis described in section 5. However, casing wear analysis is less complicated due to the limited amount of technical requirements.

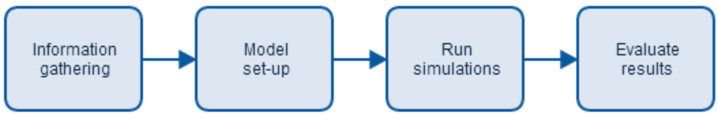

Figure 19: Casing wear analysis work process.

6.1.1 Information gathering

The three types of information needed to conduct analysis of casing wear are presented in figure 20. For simulations prior to drilling, the planned wellpath is used. When simulations are performed after drilling, actual survey data should be used to get the most accurate results.

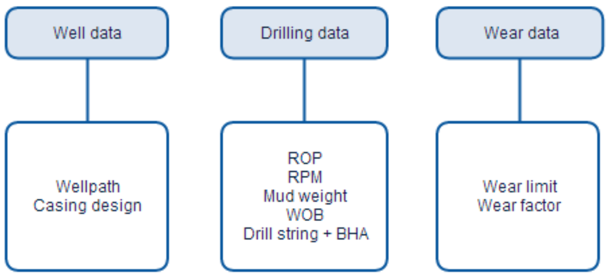

Figure 20: Technical information for casing wear simulations.

The drilling parameters can be difficult to predict, as changes may occur during operations. The effect of these parameters on predicted wear was investigated by Kjellevoll (2013) and a short summary of the results are presented in table 9.

Table 9: Sensitivity of casing wear input parameters. Modified from Kjellevoll (2013).

Parameter	Effect on predicted wear result
ROP	Yes
RPM	Yes
WOB	Small
Casing yield strength	None
Casing density	None
Casing ID	Yes
DP joint length	None
Tooljoint OD	Small
BHA length	Small
BHA OD	Yes
DP OD	Yes
Weight (BHA, HWDP, DP)	Small

As described in section 4.1 the wear factor greatly influences the result of wear simulations. The wear factor‘s dependency on several parameters makes it difficult to predict, and the primary way of determining the wear factor today is by experience from previously drilled wells (Kolltveit, 2014).

6.1.2 Model set-up

The Petris CasingWear^{TM} software only allows for simulation of wear on one casing at a time. A separate model has to be set-up for each casing.

The model set-up consists of five input steps: Survey (wellpath), wellbore, operation, wear factor and preferences. The survey and wellbore sections describe the well trajectory and casing/open hole. In the operation section, the well operations are defined. Only three operations are available to model (drilling, rotate off bottom and reaming), so wire line and coiled tubing operations has to be accounted for in extended rotate off bottom operational time. The set-up is described in detail in appendix B.1.

The wear factor can be described with a single factor for the complete well or with factor varying along the well (or drillstring). The preference section offers the choice of three different buckling models, as well as different models for calculation of the burst and collapse strength of pipes. Small differences in modelled wear is expected from the different models (Kjellevoll, 2013).

Section 6.2 contains a more detailed description of the model set-up used for Well X.

6.1.3 Evaluate results

The wear simulations results are presented as percentage of wall removed. This allows for a quick overview of the induced wear as well as the remaining wall thickness. By comparing the wear with dogleg and well inclination, the user can identify critical points where change may be required.

The results from the wear simulations have to be compared with results from the casing design to ensure that it does not affect the integrity of the casing. As described in section 3, there is a direct connection between wall thickness and casing strength, so only a limited amount of wear can be allowed.

6.2 Wear modelling

The modelling of casing wear on the 10 3/4" x 9 7/8" production casing is presented in this subsection. A more detailed description of the simulations, as well as results for the other casings are presented in appendix B.

The wellpath used for simulations is exported from Compass^{TM}. This is the planned wellpath, and minor changes are likely during drilling of the well. When survey data are available, they should be used for more accurate results. The wellpath is presented in figure 4 in subsection 2.3.3. The software has a built-in model for adding tortuosity to the wellpath. A sinusoidal tortuosity with an amplitude of 1^o and a period of 180 m is added to the original wellpath.

The wellbore is set up using data from the Petris CasingWear^{TM} tubular database. The 10 3/4" x 9 7/8" casing is set at 5 146 MD with the cross-over at 1 400 MD.

The production casing will be subject to wear during drilling of both the 8 1/2" section and the 6 5/8" section. A total of 850 meters of drilling will be done through the production casing. The operational parameters used for casing wear simulations are presented in table 10.

Table 10: Operational paramters for drilling of reservoir sections.

Drilling paramter	
Section start	5 150 MD
Section end	5 994 MD
Mud weight	2,06 sg
ROP	10 m/hr
RPM	160
WOB	100 kN

A wear factor of 3 is used for simulations on the SM125S casing in Well X. This is based on experience from previously drilled wells on the same field, as well as company standards (Qamar, 2014). The He/Kyllingstad buckling criteria is used, as well as the API model for casing burst and collapse strength.

6.3 Results and evaluation

The results from the casing wear simulations have to be compared with results from casing design calculations done in either StressCheck™ or WellCat™. The wear limits for selected load cases (Displacement to gas, kick in 5 7/8" section and mud drop) are presented in figure 21.

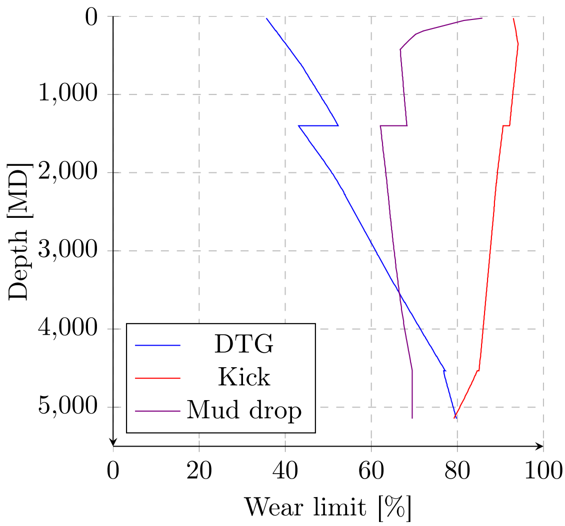

Figure 21: Wear limit for production casing.

Simulated wear on the production casing is plotted together with dogleg severity in figure 22. The wear penetration is around 9 to 10 percent for the production casing with no distinct differences between the 10 3/4" (above 1 400 MD) and the 9 7/8" casing. A correlation between high dogleg and wear penetration can be seen as wear penetration exceeds 12 percent in zones with doglegs of $2.5^o/30$m.

Compared to the wear limits presented in figure 21 the expected wear is significantly lower and should therefore not represent any problem for the well integrity.

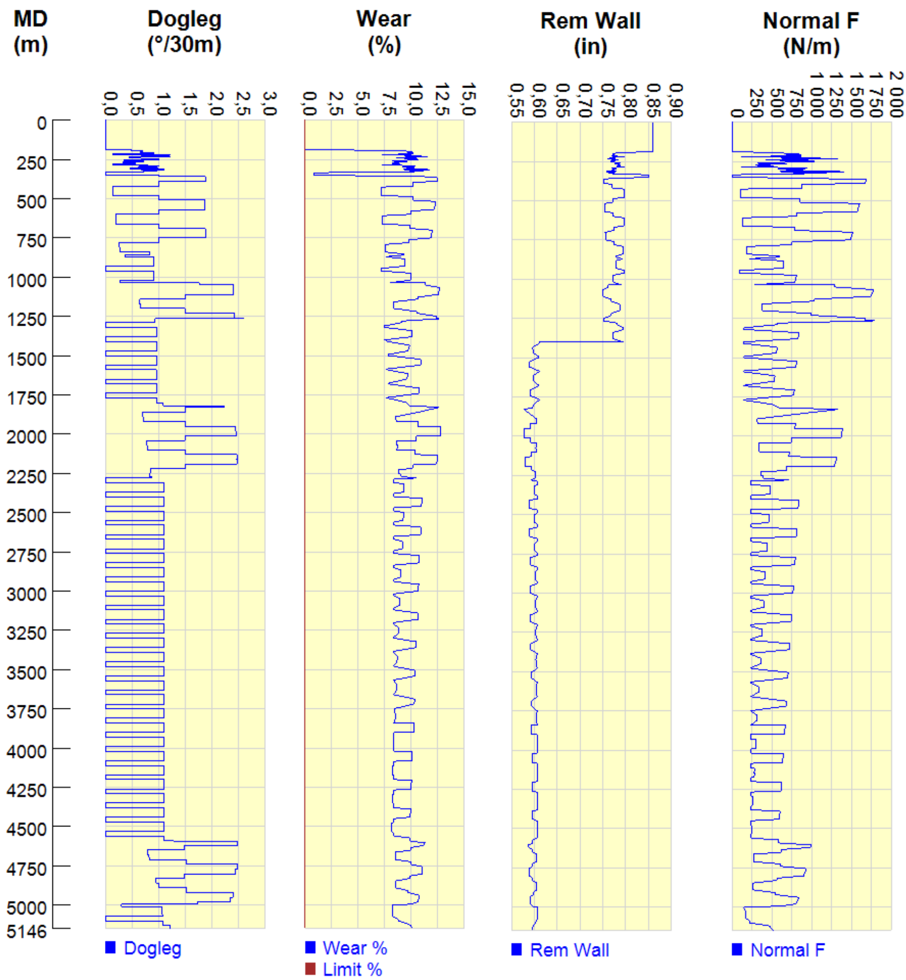

Figure 22: Petris CasingWear^{TM} simulation results for 10 3/4" x 9 7/8" production casing.

7 Discussion

Following the described work process for tubing stress analysis and casing wear, improvements to the work process can be cost saving. The focus of this thesis is to uncover the time consuming and/or high user-threshold phases of the process in order to simplify and ensure proper well engineering.

In this section, an evaluation of the complete process of well integrity modelling, from wellpath design to tubing design (ref: table 1 in subsection 2.2), will be made using results from this thesis as well as the fall project.

7.1 Work process: Tubing stress analysis

7.1.1 Identify requirements

Figure 23: Identifying requirements phase.

The process of identifying technical requirements for tubing stress analysis should be straight forward. Optimally, each operating company should have a set of company-standards collected in one document easily available to the drilling engineer. Even better would be to have them integrated in the simulation software. By linking directly from the software to the applicable standard/document, confusion about company regulations can be eliminated.

Some of the company specific requirements are summarized in the list below:

- Design factors
- DLS overrides
- Production operations
- Load cases

Companies may require different software to be used for tubing analysis. This may depend on well type. An exploration/appraisal well does not require the same degree of production simulations as a producing or injection well. Temperature and pressure also affects the need for complicated simulations. The strength of the WellCat^{TM} software is its ability to model wellbore temperature during production, injection and shut-in and its effect on annular fluid expansion and well head growth. Thus reservoirs where HPHT temperatures (150^{o}C (NORSOK D-010, 2004)) often requires casing design simulations to be carried out in WellCat^{TM}, rather than the less complicated StressCheck^{TM}.

7.1.2 Information gathering

Figure 24: Information gathering phase.

Gathering information about well, equipment and reservoir can be a time consuming process. Communication between geologists, reservoir engineers, suppliers and colleagues are often required to establish the data to form the basis for simulations.

Two methods for streamlining the information gathering have been identified:

- Reduce the number of input parameters necessary in the software.
- Collect and store information about well, equipment and reservoir in a more efficient manner.

By limiting the number of input parameters required by the software, the time spent by the engineer can be reduced. Fewer input parameters would also reduce the risk of mistakes made by the engineer thus reducing uncertainty in the results. There are two ways of achieving this: Better communication between the different engineering software (for import of wellpath, pp/frac gradients, casing depths, temperature gradient etc.) and "locking" of data that is not project specific. There is, for instance, no need for the engineer to decide on the design factors. These are defined by the company (or in some cases NORSOK/ISO standards) and should therefore not be available to change.

Another example of the overload of unnecessary input data is that the software requires the user to "tick off" a box to include *temperature deration* and *capstan effect* in calculations of tubing load. As shown in figure 11 (section 4.2), this can cause a reduction in strength of over 10 % at HPHT temperatures, which is enough to completely eliminate the burst and collapse design factors of the tubing. Unless these effects are accounted for in other ways (i.e. included in design factors), they should not be subject to change by the user of the software.

The author suggests that the input parameters are divided into three groups:

- Project specific data identified by user.
- Project specific data automatically collected from other software.
- Company specific input data common to all wells of same type.

The WellCat^{TM} input parameters have been identified and categorized in table 11 (valid only for HPHT producing wells):

Table 11: WellCat^{TM} input data.

Project specific		**Company specific**
User input	Software database	
Production rates	Wellpath	Design factors
-Oil	Gradients	Temp. deration factors
-Gas	-Pore pressure	Capstan effect
-Water	-Fracture	Production operations
Prod. fluid composition	-Temperature	Load cases
Reservoir temp/pressure	Casing design	Drilling muds
-Early phase	Rig data	Cements
-Steady state	Drilling equipment	
-Late phase	Drilling schedule	
Suggested completion		
-Tubing design		
-Production packer		
Perforation depth		

An efficient database for collecting of relevant well data would also be of great help to the drilling engineer. A central storage unit, designed and formatted specifically to store well engineering data would simplify the information gathering process for the drilling engineer. Such a central storage unit would also have the possibility of improving communication, both between the engineering disciplines, as well as with the operational unit offshore. Today, most of this information is collected in a drilling- and completion- activity document which is neither lucid nor simple.

7.1.3 Software modelling

Figure 25: Software modelling phase.

The WellCat^{TM} software has been the preferred software for tubing design since the early 1990s, and the software has not seen any major upgrade in user interface or work flow since then. This results in the software having a very small degree of interactivity which again heightens the user threshold.

A simplification of the work process is possible by adopting a more modern and interactive user interface. In combination with a reduction of input parameters this would reduce time consumption and reduce the work load for well engineering. By guiding the user through the necessary steps, one-by-one, while always letting the user have an overview of where in the process he/she is, the process becomes more comprehensible. This can be achieved by having a list of steps to go through where each is accompanied by an indicator light signaling whether or not the step has been completed correctly or needs reviewing.

Other possible improvements to the software are suggested below:

1. Include pre-defined operations and load cases.
2. Improvement of fluid inventory.
3. Include an inventory for production packers.
4. Improved graphical presentation of well and initial conditions.
5. Presentation of resulting loads on tubing

1: Most operating companies have a standard for which load cases to be run for a certain well type (producer/injector, gas lift etc.). By including these in the software the need for the user to spend time deciding on which cases to run, as well as setting them up will be reduced. This would also secure that all necessary standard load cases are investigated. Having the option of self-defined load cases in addition to the pre-defined load cases, allows for simulations of special circumstances, specific for a well.

2: Although fluids may be specific for wells, having a database of drilling and completion fluids used in the company should be possible. Drilling muds with different mud weight and rheology should not differ from tubular with different grades and weights. However, production fluids may have to be defined by the engineer as the fluid composition is project specific.

3: Inclusion of a production packer inventory with packer operating envelopes may have several positive effects for the user. Firstly, it would not require the engineer to spend time obtaining these data. Secondly, it would allow the user to question the supplier's packer recommendation. The engineer could, instead of requesting the supplier to do it, evaluate the available packers and decide on the most economic and safe solution.

4: Being able to graphically see how the model is set up would reduce uncertainties about the model. A graphical overview of the initial conditions in the well, including pressures, fluids and temperatures, allows the user to quickly see if the model is set up correctly.

5: The software has a graphical presentation of results that allows the user to quickly see if the safety factors are compromised (as shown in figure 16). There is also a possibility to investigate each load case separately as well as exporting the loads to a spreadsheet. There is, however, no deeper analysis of the load cases. This means that it is up to the user to analyze the results to figure out where any potential problem is. The software should present the source of the induced stresses. Say, if the axial safety factor is compromised at one point in the tubing, it should be possible to determine the distribution of the sources of stress; how much of the stress comes from temperature induced elongation, piston forces, bending or other processes (ref: section 3.2).

7.1.4 Results evaluation / Quality assurance

Figure 26: Quality assurance phase.

For safety reasons, all simulations are reviewed by a second engineer to reduce the risk of mistakes. The WellCat^{TM} software generates automatic reports of both input data and results, but they are rarely used. More often the reviewer goes through the same steps as the engineer who did the simulations (Kolltveit, 2014).

An illustrative report, where significant input data is presented along with the simulated load cases and graphically presented results, would reduce the peer review work load. By reducing the amount of data present in the current WellCat^{TM} reports the reviewer gains a quicker overview. This can be achieved if the input parameters are reduced as suggested in subsection 7.1.2.

7.2 Work process: Casing wear analysis

7.2.1 Information gathering

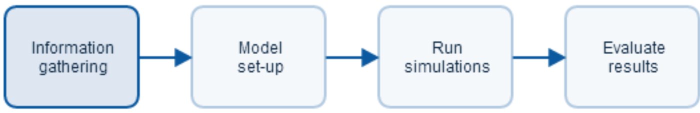

Figure 27: Information gathering phase.

The amount of data needed for casing wear simulations are limited, but can in many cases be difficult to predict. From table 9 we can draw the following conclusion about the well and drilling data:

- The only material parameters with significant effect on modelled wear is the ratio of casing ID to drill string OD. This is due to alteration of the contact pressure.
- The operational parameters ROP and RPM affect the wear as they have a significant effect on the sliding distance.

The casing and drill string geometries are usually easy to establish as both casing design and drill string design normally has been investigated prior to casing wear simulations. The more problematic part is to establish the operational drilling parameters: ROP and RPM. Normally, an assumption has to be made regarding these parameters. However, data from nearby wells can be used to estimate drilling progression.

In addition to well and drilling data, the most important parameter is the wear factor. Although very difficult to predict, it should be based on logged wear from similar wells on the same field if such data is available. For wells on new fields however, there are no industry practice for prediction of wear factor. With the number of parameters affecting the wear factor, a simple practice for wear factor prediction is hard to establish. One suggestion could be to have a standard wear factor for different well geometries, but due to the large amount of variations in well paths (and tortuosity), this is hard to accomplish in practice.

7.2.2 Software modelling

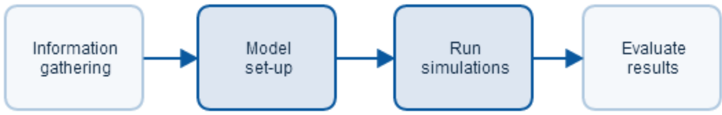

Figure 28: Software modelling phase.

Petris DrillNET CasingWear^{TM} is the industry leading software for casing wear simulations. CasingWear is one of several modules in the software and was originally developed by Maurer Engineering in the DEA-42 – Improved Casing and Riser Wear Technology project in 1997. Petris was in August 2012 bought by Halliburton and the DrillNET^{TM} software will in the future be included in the Landmark EDM software package along with WellCat^{TM} WellPlan^{TM} and Compass^{TM} (Halliburton, 2012).

The software has well defined work flow consisting of five steps as described in subsection 6.1.2. These are both easy to use and quick to perform. The main shortcoming of the software is its inability to model a complete well at once. The software requires each casing to have its own case, where all input parameters has to be repeated. This increases the work load on the engineer by having the user do repetitive work. The software also lacks a well database where wellpaths and casing design are stored.

Better implementation with other engineering tools should also be present, simplifying the import of wellbores and drill strings. Improvements in this area are expected after the above mentioned acquisition and implementation in the Landmark EDM package.

7.2.3 Results evaluation

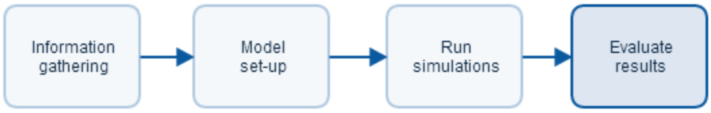

Figure 29: Results evaluation phase.

There is no easy way to compare results from the casing design calculations with the casing wear results. The CasingWear^{TM} software has the ability to plot a single wear limit in the results presentation, however, as shown in section 6.3, the wear limit is not constant along the well.

As with the tubing stress analysis previously described, the CasingWear^{TM} software lacks the ability to present the input parameters and simulation results in an orderly manner. With wellpaths extracted from a company database, one source of error is removed. By allowing for quick and efficient peer review by presenting all relevant information in a software generated report, the risk of mistakes can be further reduced. For now, the drilling engineer has to spend time compiling a report for review by colleagues.

7.3 The complete work process: From wellpath to completion

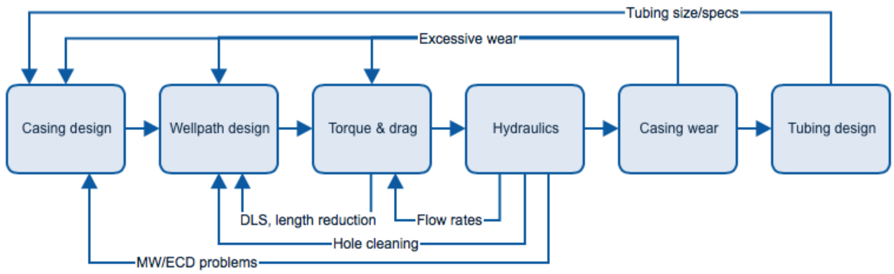

Figure 30: Work process for well engineering.

Figure 30 shows the main steps an engineer has to go through for the engineering of a well. All steps are independent and affecting the integrity of the well. As the figure illustrates, the steps are interconnected and affecting each other in different ways. This makes the engineering of a well an iterative process.

The software tools available to drilling engineers, have been investigated through this thesis, together with the fall project (Lokna, 2013). The software are mostly independent of each other and to complete the integrity verification of a well, the user has to work through all of them to ensure the design is within the technical requirements. The iterative nature of the process means that these steps often are repeated several times before a design is concluded upon. This is a time consuming and complicated process which requires a high degree of technical understanding from the user.

The software offers the ability to simulate nearly all situations imaginable. Although this offers a great amount of possibilities for the user, it also complicates the process as it leaves many choices for the user to decide. An example is the user-defined load cases. This is favorable when simulating uncommon situations specific for a well, but it leaves room for error by not ensuring that all the necessary load cases are included. It is up to the user to ensure that the simulations carried out are in accordance with the technical requirements of the company.

The author has two suggestions that could simplify the work process for the drilling engineer:

1. Implementation of technical requirements in software.
2. Improved communication between the different software models.

1: The most effective improvement, both for safety and time consumption, would be to implement the technical requirements for the design, in the software. This would simplify the work process as it would reduce the time spent on identifying requirements. It would also lower the user threshold by reducing the need for theoretical understanding of the downhole situations modelled.

2: The iterative nature of the work process exposes the software's lack of communication between each other. The changes made in one software may significantly affect the results of simulations in another software. By letting the software interact with each other, the need to go back and forth between the software can be reduced, thus reducing the work load on the user.

Such an iterative process, which has been described in the previous sections, should be optimal for modern computer software. Highly simplified, one could say that, based on certain geological (pp/frac, temperature and reservoir targets) and production (fluid composition, flow rates and desired completion) input parameters the software should be able to suggest, with minimal participation from the user:

- A casing program designed to handle the loads it would see during drilling and production.
- A wellpath, minimizing drilling length and DLS, and optimized for hydraulics, torque and drag, and casing wear.
- A completion investigated for all load cases relevant for the well type.

8 Conclusion

This thesis has gone through the integrity verification of tubing and casing wear for an HPHT well on the NCS. Based on suggested completion design and planned operations, the tubing stresses and casing wear have been analyzed using the industry leading software tools. The intention of this work has been to disclose time consuming elements, limitations and weaknesses of the work process. The following main points of improvement to the work process have been identified:

- Relevant technical requirements (API, NORSOK and company requirements) should be implemented in the engineering software. This would reduce the amount of time spent identifying requirements and reduce the risk of human error in the integrity verifications.
- Significant amount of time is spent identifying the relevant information for integrity verification. This can be reduced by a suggested limitation to software input parameters. A structured company database for collection of well information should also be established.
- A high level of theoretical knowledge is required to evaluate simulation results. Evaluation and peer review could be simplified by software generated reports focusing on relevant input parameters and explanation of the results.
- A simplification of the work process can be achieved by establishment of a mutual software platform that allows for better communication between the software models.

9 Further Work

Further work on simplification of the work process should include:

- In-depth analysis of the casing design features of the WellCat^{TM} software.
- Investigate whether there are other software, less known to the public, available for integrity verification modelling.
- Develop a step-by-step guide for the different software models, including technical requirements.
- In-depth analysis of the calculations behind, and the reliability of, the results in WellCat.
- Investigate the work processes of the operational and post-operational phases for a drilling engineer.

Abbreviations

Symbol	=	definition
APB	=	Annular pressure build-up
API	=	American Petroleum Institute
BHA	=	Bottomhole asembly
CPT	=	Contact pressure threshold
DLS	=	Dogleg severity
DP	=	Drillpipe
DTG	=	Displacement to gas
ECD	=	Equivalent circulating density
GOR	=	Gas-oil rate
HPHT	=	High pressure high temperature
ID	=	Inner diameter
MD	=	Measured depth
MPD	=	Managed pressure drilling
MW	=	Mud weight
NCS	=	Norwegian continental shelf
OD	=	Outer diameter
OLF	=	Norwegian Oil and Gas Association
PBR	=	Polished bore receptacle
ROP	=	Rate of penetration
RPM	=	Revolutions per minute
SIWHP	=	Shut-in wellhead pressure
TVD	=	True vertical depth
UTS	=	Ultimate tensile strength
VME	=	von Mises equivalent (stress)
WH	=	Wellhead
WHG	=	Wellhead growth
WOB	=	Weight on bit

Nomenclature

α	=	DLS
δ	=	Length change
ε	=	Strain
θ	=	Hole inclination
μ	=	Poisson's ratio
σ	=	Stress
ψ	=	Work function
ω	=	Buoyed weight
A	=	Area
C_t	=	Coefficient of thermal expansion
D	=	Diameter
D/t	=	Pipe slenderness
DF	=	Design factor
E	=	Youong's Modulus (for tubing stress)
E	=	Specific removal energy (for casing wear)
F	=	Force
I	=	Moment of inertia
L	=	Length
p	=	Pressure
r	=	Radius
S	=	Sliding distance
T	=	Temperature
t	=	Wall thickness
V	=	Volume of material removed
W	=	Frictional work
WF	=	Wear factor
Y_p	=	Yield strength

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A Detailed tubing analysis

A.1 About the WellCat™ software

The WellCat™ software contains a predefined, often by company, pipe inventory. Here tubulars are specified with weight, grade and load ratings used for the stress calculations. The software automatically calculates the load ratings for the pipe based on the grade, weight and wall thickness data provided by the user. API Bulletin 5C3 (equivalent to ISO 10400) formulas for internal yield, collapse pressuer and body yield strenght are used for the calculations (WellCat User Manual, 2006). Figure 31 shows an extract of the tubing and casing inventory. By creating WellCat™ templates the program allows for restriction of available inventory. This allows for region- or project- specific inventories to be created based on availability and logistics or other factors.

	OD (in)	Weight (ppf)	Grade or Name	ID (in)	Type	Drift (in)	Ratings		
							Burst (bar)	Collapse (bar)	Axial (kip)
1	4,500	10,500	13CR80 (ACTIVE)	4,052	Standard	3,927	480,49	340,29	240,7
2	4,500	10,500	L-80 (ACTIVE)	4,052	Standard	3,927	480,49	340,29	240,7
3	4,500	10,500	C-95 (ACTIVE)	4,052	Standard	3,927	570,58	366,22	285,9
4	4,500	10,500	SM95S (ACTIVE)	4,052	Standard	3,927	570,58	366,22	285,9
5	4,500	10,500	T-95 (ACTIVE)	4,052	Standard	3,927	570,58	366,22	285,9
6	4,500	10,500	C-110 (ACTIVE)	4,052	Standard	3,927	660,67	383,00	331,0
7	4,500	10,500	S13CRS110 (ACTI	4,052	Standard	3,927	660,67	383,00	331,0
8	4,500	10,500	P-110 (ACTIVE)	4,052	Standard	3,927	660,67	383,00	331,0
9	4,500	10,500	SM25CRW-125 (A	4,052	Standard	3,927	750,76	402,00	376,1
10	4,500	10,500	SM125S (ACTIVE)	4,052	Standard	3,927	750,76	402,00	376,1
11	4,500	17,000	S13CRS110 (ACTI	3,740	Standard	3,615	1120,78	1172,73	541,0
12	5,000	15,000	13CR80 (ACTIVE)	4,408	Standard	4,283	571,44	499,88	349,9
13	5,000	15,000	L-80 (ACTIVE)	4,408	Standard	4,283	571,44	499,88	349,9
14	5,000	15,000	SM95S (ACTIVE)	4,408	Standard	4,283	678,58	559,04	415,6
15	5,000	15,000	C-95 (ACTIVE)	4,408	Standard	4,283	678,58	559,04	415,6
16	5,000	15,000	C-110 (ACTIVE)	4,408	Standard	4,283	785,73	610,29	481,2

Figure 31: Pipe inventory.

The inventory also contains information about temperature deration of the pipe. For each grade it is possible to input up to ten different temperatures and strength reduction factors. The program then connects the points linearly and uses this data to reduce the material strength (WellCat User Manual, 2006). The deration factor as a function of temperature for the relevant steel for well X is plotted in figure 32. As the figure shows, there is nonlinearity to the deration factors for many of the steel grades. This illustrates that using a "default steel" deration factor for all grades may be non-conservative and a source of error if chosen.

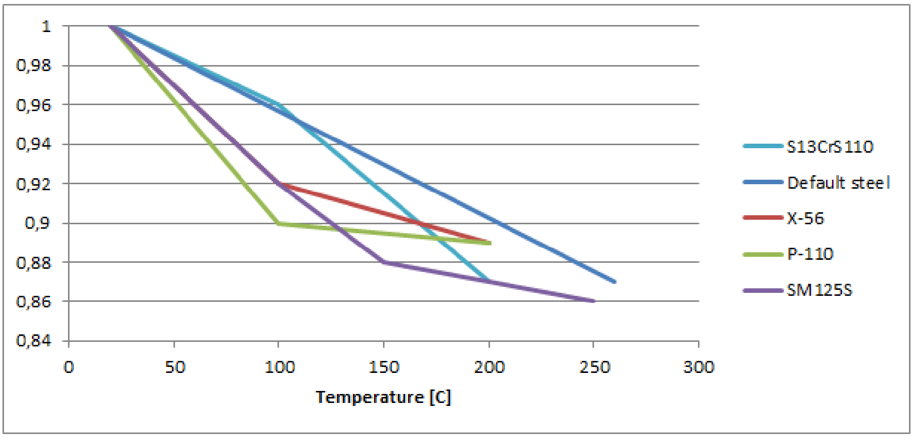


Figure 32: Temperature deration.

The fluid inventory contains all fluids used for simulations. This includes different mud types (simple or complex), brines, foams, polymers, cement slurries and hydrocarbons. Due to the diversity and complexity of fluids they have to be specified for each project. As WellCat^{TM} is not the preferred software for hydraulic simulations, the fluid parameters for muds are not of the highest importance. The thermal properties are however important for wellbore temperature calculations and the mud weight for pressure calculations.

Hydrocarbons can be defined as either a vapor-liquid equilibrium (VLE) or a standard hydrocarbon. For a gas fluid with heavy components, as is the case for well X, it is recommended by the software to use the VLE setting. However, this setting prevents the user from determining a desired gas-oil ratio (GOR) when defining the production operations. The software uses the Peng-Robinson equation of state to calculate a GOR based on the user-defined oil production rate. This property of the VLE setting prevents the simulation of different gas rates that occur during the production lifespan of a well. In order to do production simulations with different GOR the VLE setting cannot be used.

A.2 Model description

Wellpath

The wellpath used in the WellCat^{TM} simulations is exported from Compass^{TM}. To compensate for wellbore tortuosity, an override is added to the original DLS in the wellpath. The DLS is plotted as a function in depth in figure 33.

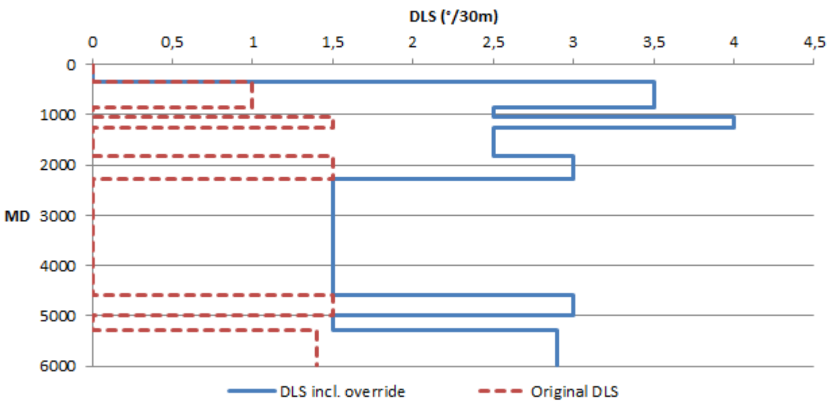


Figure 33: DLS incl. override.

Casing and tubing configuration

The casing strings, as viewed in WellCat^{TM} is presented in figure 34. The well is suggested completed with tapered tubing. A 5 1/2" tubing is preferred to limit the pressure loss during production, but the limited clearance in the 7" liner requires the use of 4 1/2" tubing in the bottom of the tubing string. The cross-over is placed at 4 800 MD with the base of the tubing reaching 5 068 MD. The completion is presented in table 12 and figure 14.

After the drilling of reservoir section *one*, a 7" liner will be cemented in place. Although not optimal with regards to sand control, this has to be done to ensure well integrity for further drilling of the 6 5/8" section and reservoir *two* and *three*. The 6 5/8" section will be completed with a 4 1/2" liner cemented

	Name	Type	OD (in)	MD (m)			Hole Size (in)	Annulus Fluid
				Hanger	TOC	Base		
1	Conductor	Casing	30.000	24.00	187.00	338.00	36.000	Fresh Water
2	Surface	Casing	20.000	24.00	187.00	1278.00	24.000	Fresh Water
3	Intermediate	Casing	14.000	24.00	2169.00	4346.54	17 1/2	1,48 sg OBM*
4	Production	Casing	10 3/4	24.00	4534.00	5146.00	12 1/4	1,84 sg OBM*
5	Production	Liner	7.000	4914.00	4914.00	5518.00	8 1/2	2,06 sg CsK
6	Production	Liner	4 1/2	5071.00	5071.00	5987.00	5 7/8	2,03 sg CsK
7	Production	Tubing	5 1/2	24.00		5068.00		1,05 sg PP Fluid
8								

Figure 34: Casing set-up.

Table 12: Tubing specifications.

Size [in]	Grade	Weight [lbf]	Depth [MD]
5 1/2	S13CrS110	26,00	24 - 4 800
4 1/2	S13CrS110	17,00	4 800 - 5 068

in place. The perforations in reservoir *three* will be at a depth of 5 900 MD.

Geological data

The undistributed temperature in the formations is shown in figure 35 and the pore pressure and fracture gradient is plotted in figure 36.

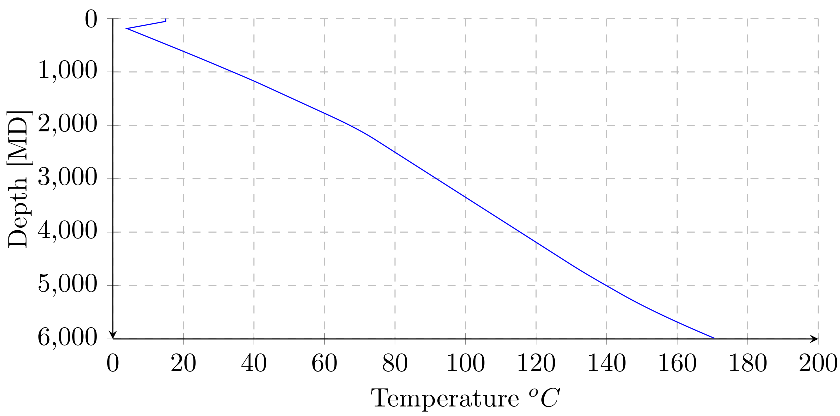


Figure 35: Unditributed temperature

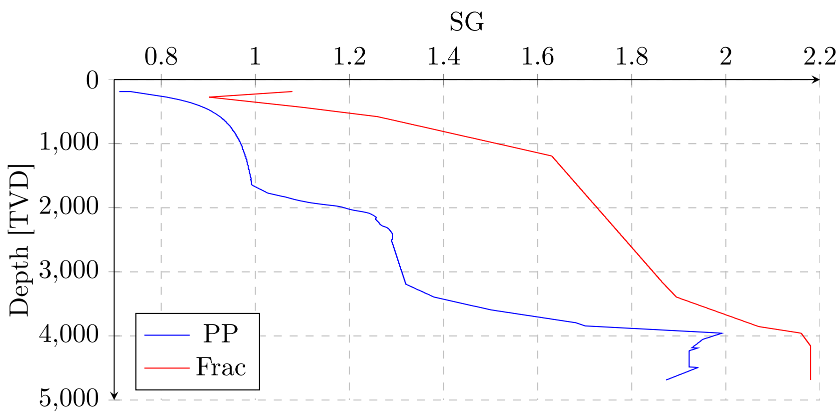


Figure 36: Pore pressure and fracture gradient.

Production data

WellCats™ inability to model production from different pressure zones requires the user to choose *one* production zone. In the case of well X production from reservoir *three* should be modelled as this zone is the source of the highest pressures and temperatures during operations. This is a conservative estimate as production from reservoir *three* only is unlikely. If this reservoir proves to contain hydrocarbons it will be co-produced with reservoir *one* and possibly reservoir *two*. This will reduce the resulting temperature, thus reducing forces on tubing and casing. The production fluid composition is shown in figure 37.

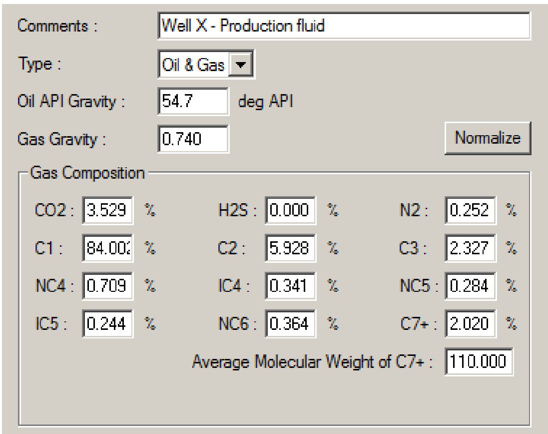


Figure 37: Production fluid composition

Based on data from the reservoir engineering group an estimation of production rates for the lifespan of the well has been made. The production rates are shown in table 13 and forms the basis for the production simulations in WellCat™.

Table 13: Production rates.

Production phase	Early life	Steady state	Late life
Gas [Mm^3/day]	4 500	4 500	250
Oil [m^3/day]	1 700	1 500	50
Water [m^3/day]	0	5	100

A.3 Production operations

WellCat^{TM} requires a series of production operations to be defined in order to carry out load case simulations on the well. The production operations produce temperature and fluid flow profiles for the well during different production scenarios defined by the user. Fluid properties, pressures and flow rates highly affect the temperature profiles created. Ensuring correct values for these parameters are important for the integrity of the simulation (Bellarby, 2009). These profiles form the basis for the tubing stress analysis in the program. The software has the ability to simulate temperature for either a finite time period or a steady state production scenario (WellCat User Manual, 2006).

Flowing well

For creating temperature and flow profiles, there are three well situations that must be evaluated. The first is a flowing well. This includes the clean-up (first flow) as well as production in the early and late life of the well. Transient production conditions should also be investigated (referred to as "steady state").

The high-temperature production fluid will heat the tubing, causing axial forces to develop. Reservoir temperature is assumed similar for the complete life of the well. The reservoir is planned depleted without pressure support so a decline in reservoir pressure is expected. The pressures used for temperatrue and flow simulations are presented in table 14.

Table 14: Reservoir pressure.

	Early life	Steady state	Late life
Pressure (5 900 MD)	865 bar	830 bar	750 bar

Shut-in

The second situation to be modelled is a shut-in of the well. A shut-in can be a critical situation for the tubing, as both pressure and temperature can be high. Both short and long shut-ins should be modelled. The length of the long shut-in should be long enough for the well to cool and reach the undistributed temperature (geothermal gradient). The long shut-in case should not be critical as the pressure will be lower than during the pressure test with the same temperature.

The short shut-in can however be a critical situation. A short shut in during steady state production is considered the worst case as this gives a well with high SIWHP while heated by the producing fluid. Short shut-in should be modelled for all three phases of the well life. WellCat^{TM} uses either the Soave Redlich–Kwong (SRK) or the Benedict–Webb–Rubin (BWR) equation of state to calculate the gas gradient in the well during shut-in. Simple pressure calculations with a single gas gradient would be overly conservative as the gas density is heavily dependent on pressure.

Injection

Even though no injection is planned for well X, bullheading and killing operations should be simulated to investigate the stresses induced in the tubing. Injection of a cold injection fluid can cause large temperature changes which in addition to high pressures can cause severe stresses in the tubing. The bullheading scenario is based on the maximum fracture pressure at perforation depth plus 35 bar. A separate simulation covering the starting of a bullheading operation should also be done. This scenario would have the well in a shut-in state, filled with gas, and subject to bullheading pressure at the wellhead. This is a critical situation as the pressure in the well is higher than during a conventional shut-in.

Table 15: Injection simulation.

Operation	Fluid	Pressure [bar]	Flow	Volume	Temp
Bullheading	1,03 SW	Frac + 35 bar	1 000 m3/d	165m3	4^oC
Kill	2,06 Brine	Frac + 35 bar	1 000 m3/d	110m3	10^oC

An overwiev of the production operations defined in the software is presented in table 16.

Table 16: Production operations.

Production	Clean-up
	Early life
	Steady state
	Late life
Shut-in	Short: Early life
	Short: Stedy state
	Short: Late life
	Long: Steady state
	Long: Late life
Injection	Start bullheading
	Bullheading
	Kill operation

A.4 Load cases

Initial conditions

In order to carry out load simulations on the tubing string, the initial well condition has to be described. The initial conditions are the conditions after the production packer is set and setting pressure is released. The initial conditions form the basis for all other load calculations and errors in the initial conditions therefore leads to incorrect loads. Pressure and temperature has to be defined for both tubing and annulus side of the well. Fluids present in the well are also of significance as they influence temperature development.

Pressure test: Tubing

To validate tubing integrity, a pressure test has to be carried out. The tubing is pressured up against the plug in the tailpipe. The pressure test should be performed to the highest SIWHP the well will see during production. Pressure simulations for well X is shown in figure 38. The highest SIWHP for well X will occur during the "start bullheading" scenario (indicated by red circle).

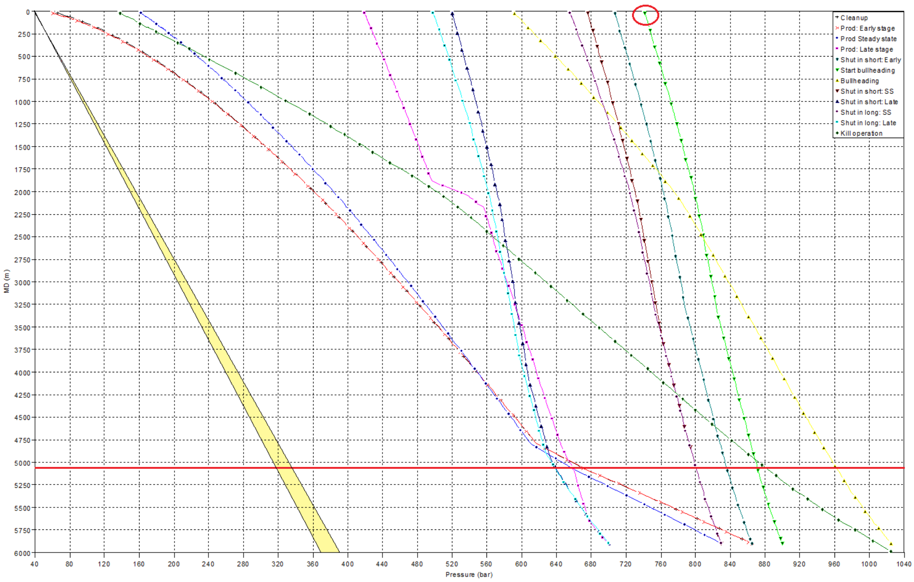


Figure 38: Tubing and annulus pressure.

Pressure test: Annulus

The purpose of the annulus pressure test is to exert a differential pressure on the packer similar to what it will see during production. In figure 38 the packer depth is marked by a red line. The annular pressure is marked by a yellow area. The highest differential pressure the packer will see will be 572 bar during bullheading. A 35 bar margin should be added on top of the expected pressure giving a test pressure of 600 bar.

Tubing leak

Tubing leak below a subsurface safety valve (SCSSSV) can cause collapse loads on the tubing and should therefore be ran as an independent load case. The worst case scenario is when the well is shut in by the SCSSSV in the early phase and a tubing leak transfers the tubing pressure to the annulus side. The shut-in pressure will then act on top of the annulus fluid on the annulus side and on top of the production fluid on the tubing side. Above the SCSSSV the pressure is atmospheric. This gives a collapse pressure as the annulus fluid density is greater than the production fluid density. The differential pressure will be at the highest at packer depth or right above the SCSSSV. A tubing leak load case is run in the early phase of well life as the shut-in pressure is at the highest.

A.5 Tubing results

The results from the tubing analyiss is presented below. The results are presented as absolut safety factors for collapse (Figure 39), burst (Figure 40), axial (Figure 41) and tri-axial (Figure 42).

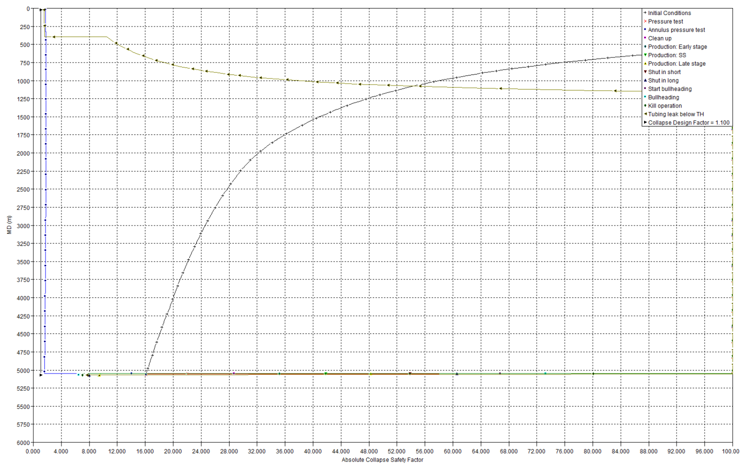


Figure 39: Collapse safety factor.

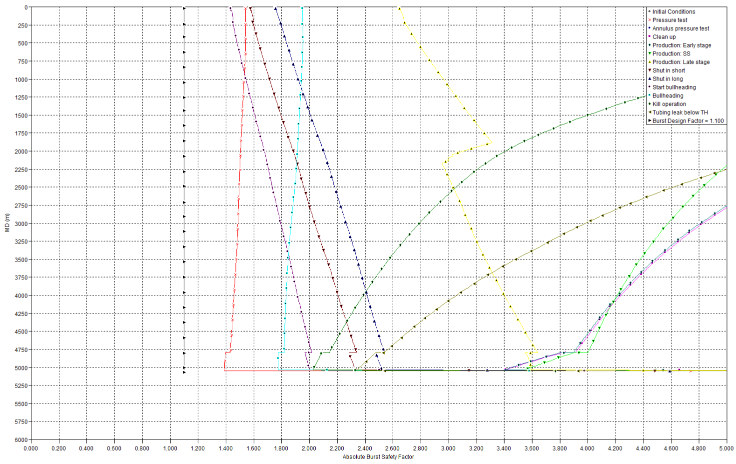


Figure 40: Burst safety factor.

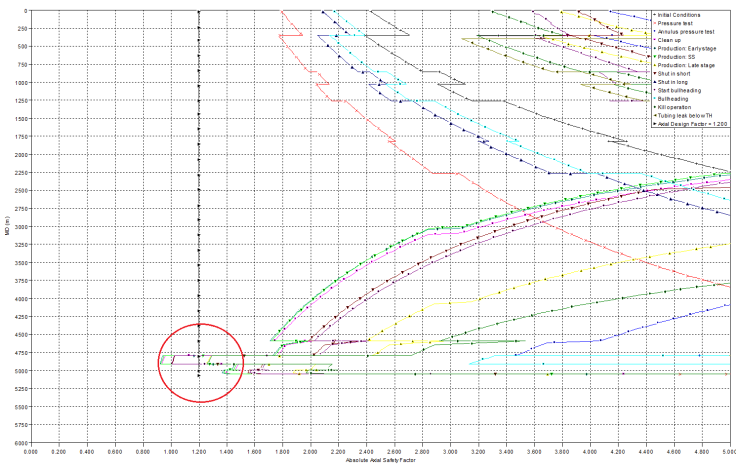


Figure 41: Axial safety factor.

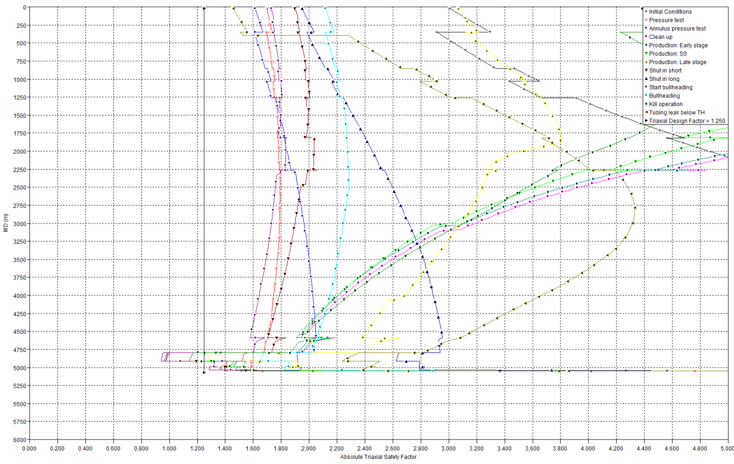


Figure 42: Tri-axial safety factor.

A.6 Packer results

The production packer loads relative to the operational envelope of the suggested packer is presented in figure 43. The detailed loads are presented in figure 44.

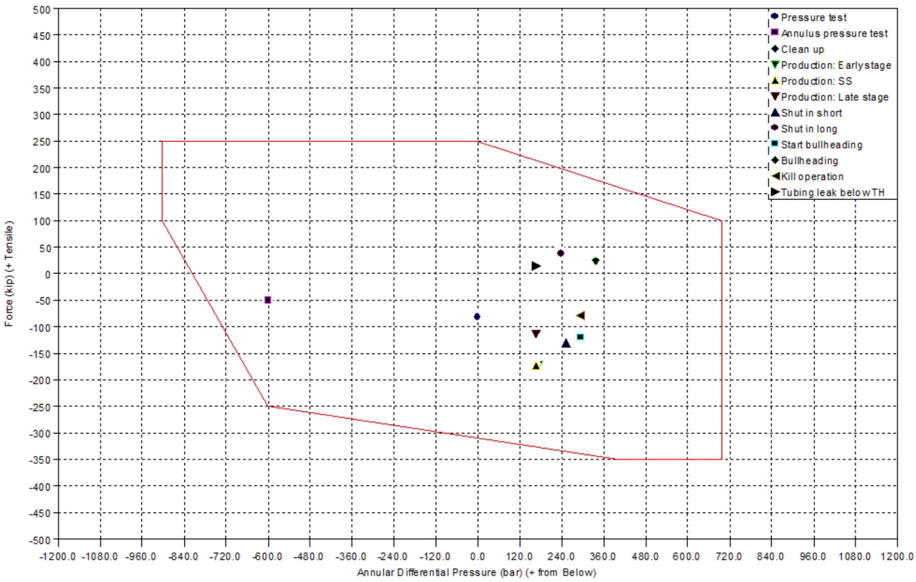


Figure 43: Production packer loads plot.

Load	Tubing-to-Packer Force (kip)	Axial Load Above (kip)	Axial Load Below (kip)	Annulus Pressure Above (bar)	Annulus Pressure Below (bar)	Temperature (°C)	Latching Force (kip) Force (kip)	Packer-to-Casing (kip)	Differential pressure (bar)
Initial Conditions	4,7	-32,4	-27,6	396,09	396,10	141,244	---	4,7	0,0
Pressure test	82,9	8,2	91,1	396,09	396,08	141,244	---	82,9	0,0
Annulus pressure test	50,2	-77,8	-27,6	993,60	396,08	141,244	---	157,7	-597,5
Clean up	169,7	-216,8	-47,1	493,36	667,55	172,251	---	138,3	174,2
Production: Early stage	173,3	-220,4	-47,1	492,99	667,69	172,417	---	141,9	174,7
Production: SS	173,3	-219,4	-46,2	487,31	654,77	171,176	---	143,1	167,5
Production: Late stage	113,8	-160,2	-46,3	493,06	658,54	165,058	---	84,1	165,5
Shut in short	131,1	-187,5	-56,4	547,32	800,65	170,921	---	85,5	253,3
Shut in long	-37,2	-19,3	-56,4	559,98	800,63	144,165	---	-80,5	240,7
Start bullheading	121,0	-182,5	-61,5	576,26	871,08	170,921	---	68,0	294,8
Bullheading	-24,4	-43,6	-68,0	624,18	961,40	158,490	---	-85,1	337,2
Kill operation	79,8	-142,0	-62,2	585,92	879,41	167,189	---	27,0	293,5
Tubing leak below TH	-14,9	-44,0	-59,0	1111,00	833,56	141,244	---	35,0	-277,4

Figure 44: Production packer loads.

A.7 Annular fluid expansion

WellCat^{TM} simulations for annular fluid expansion has beem conducted and the result is presented in figure 45. A large pressure build-up is seen in the A-annulus. This indicates a need for venting of the A-annulus at the wellhead.

	String Annulus	Region			Incremental AFE Pressure (1) (bar)	Incremental AFE Volume (2) (m³)
			Top (m)	Base (m)		
1	14" x 13 5/8" Intermediate Casing	Region 1	24.00	2169.00	0.00	8.48
2	10 3/4" x 9 7/8" Production Casing	Region 1	24.00	4534.00	0.00	4.76
3	5 1/2" x 4 1/2" Production Tubing	Region 1	24.00	5050.00	1100.47	6.42
4						
5	**(1) Pressure change caused solely by the Annular Fluid Expansion (AFE) phenomenon.**					
6	**(2) Volume change caused solely by the Annular Fluid Expansion (AFE) effect.**					

Figure 45: Annular fluid expansion (WellCat^{TM})

B Casing wear simulations

B.1 Input paramters

There are six steps to go through when setting up a casing wear analysis in Petris DrillNET. This section gives a short presentation of the process and the paramters needed.

Project

The project section allows the user to fill inn information about the well subject to simulations. This section is not mandatory, and do not affect the simulation results in any way.

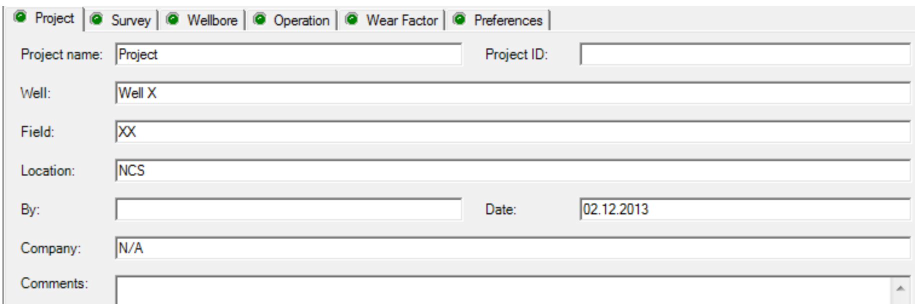


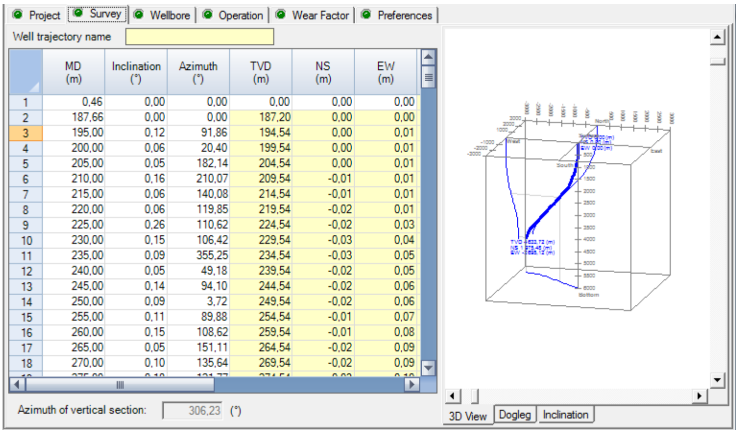
Figure 46: Project information input.

Survey

In the survey section, the wellpath has to be included. There are three ways of including the wellpath in the software:

- Import wellpath from Compass^{TM}.
- Manually typing in MD, inclination and azimuth.
- Built-in well-planner in software.

The built in well-planner has not been investigated in this thesis. Copying the wellpath from Compass^{TM} has been identified as the simplest solution and this has been done in figure 47.



	MD (m)	Inclination (°)	Azimuth (°)	TVD (m)	NS (m)	EW (m)
1	0,46	0,00	0,00	0,00	0,00	0,00
2	187,66	0,00	0,00	187,20	0,00	0,00
3	195,00	0,12	91,86	194,54	0,00	0,01
4	200,00	0,06	20,40	199,54	0,00	0,01
5	205,00	0,05	182,14	204,54	0,00	0,01
6	210,00	0,16	210,07	209,54	-0,01	0,01
7	215,00	0,06	140,08	214,54	-0,01	0,01
8	220,00	0,06	119,85	219,54	-0,02	0,01
9	225,00	0,26	110,62	224,54	-0,02	0,03
10	230,00	0,15	106,42	229,54	-0,03	0,04
11	235,00	0,09	355,25	234,54	-0,03	0,05
12	240,00	0,05	49,18	239,54	-0,02	0,05
13	245,00	0,14	94,10	244,54	-0,02	0,06
14	250,00	0,09	3,72	249,54	-0,02	0,06
15	255,00	0,11	89,88	254,54	-0,01	0,07
16	260,00	0,15	108,62	259,54	-0,01	0,08
17	265,00	0,05	151,11	264,54	-0,02	0,09
18	270,00	0,10	135,64	269,54	-0,02	0,09

Figure 47: Wellpath input.

The software also has a built-in function for adding tortuosity to the wellpath. After the wellpath have been included in the software, tortuosity can be added to zones of the well by wither a sinusodial or random way. Figure 48 shows the tortuosity function of the software.

Wellbore

The wellbore sections requires the user to define the state of the wellbore prior to wear occurs. The casing subject to wear analysis has to be defined with depths, OD, ID, yield strength, density and wear limit (if available). As discussed in section 6.1, most of these parameters are insignificant for the simulation results, but the software requires theses data to be included here.

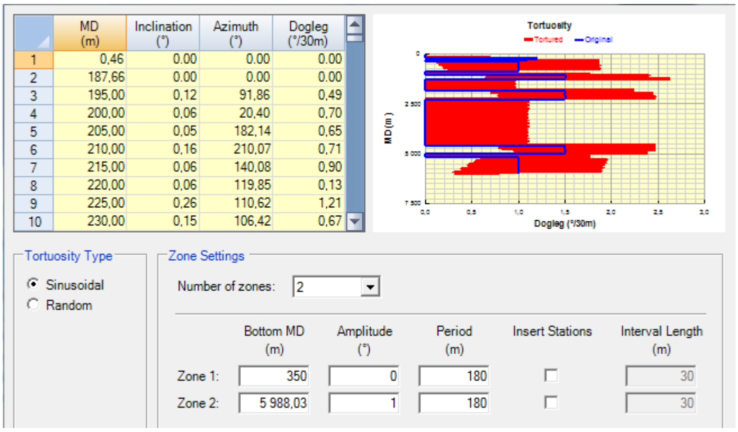


Figure 48: CasingWear$^{\mathrm{TM}}$ tortuosity function.

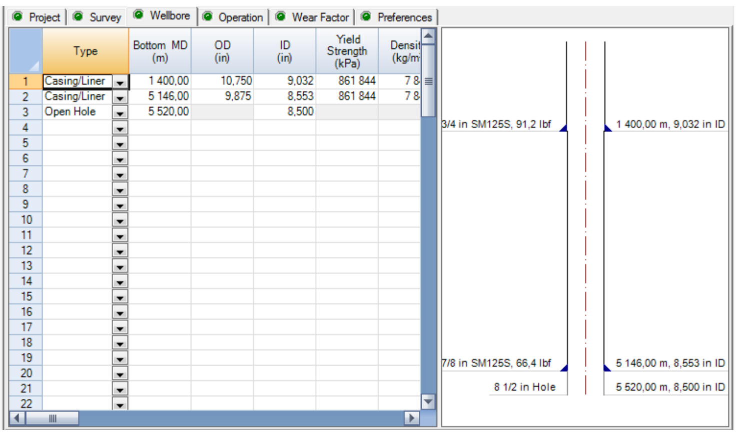


Figure 49: Wellbore information input section.

Operation

All drilling operations seen by the chosen casing are defined in the operation section. The software has three pre-defined operations: Drilling, rotate off bottom and reaming. Operational paramters such as WOB, ROP and RPM are included in this section. The operations seen by the production casing has been defined in figure 50. For each operation, a drill string has to be defined with its physical properties (OD, ID, length, denisty, weight and Young's Modulus).

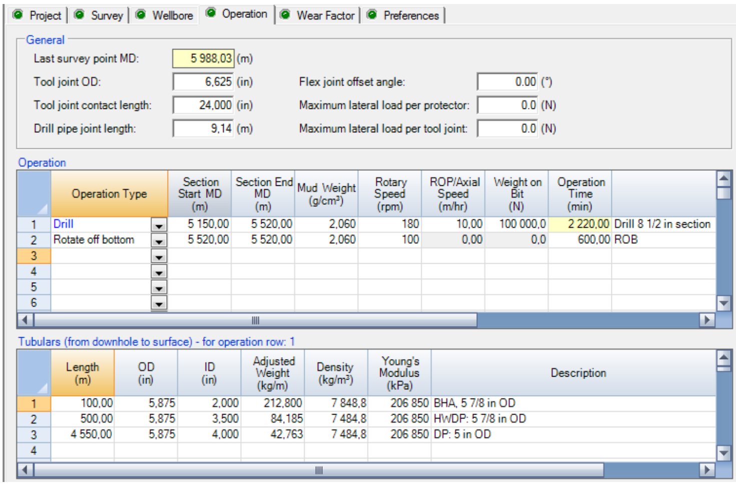


Figure 50: Operational parameters input.

Wear factor

The wear factor can be included either as a single factor for the complete well, which is preferred for homogenous casing strings. For design where the casing grade varies along the well the need for multilple wear factors occurs. The software allows for variation of wear factor along either the well or the drill string. This is practical for situations where different drill pipes (or hardbanding materials) are used. Figure 51 shows the wear factor input section. A wear factor of 3,0 has been used throughout thi thesis.

Preferences

Three different buckling models are available to the user of the software:

- Dawson/Paslay (sinusoidal) and Chen/Cheatham (helical) criteria.

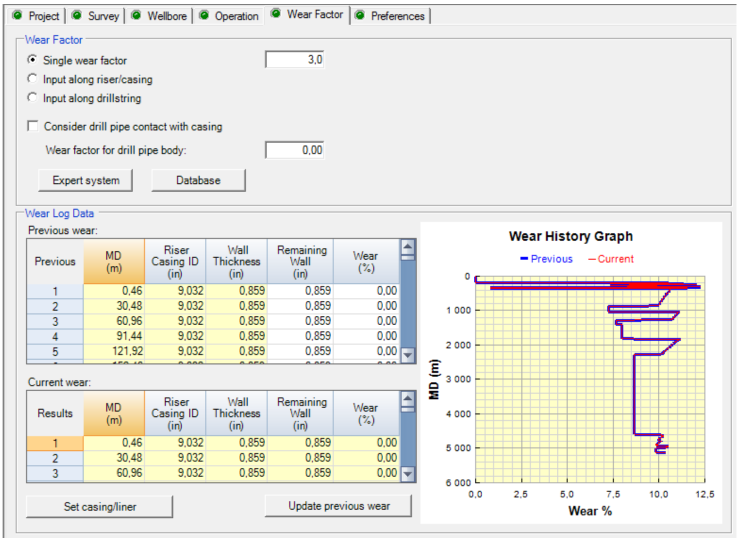


Figure 51: Wear factor input.

- Wu/Juvkam-Wold (sinusoidal and helical) criteria.
- He/Kyllingstad (sinusoidal and helical) criteria.

For simulations in this thesis, the He/Kyllingstad criteria are used. The software also allows for choosing between three burst and collapse strength options: Biaxial stress, API equation and OTS equation.

B.2 Casing wear results

This section presents the results from the casing wear simulations carried out in DrillNET CasingWear^{TM} for all casings in Well X.

20" Surface casing

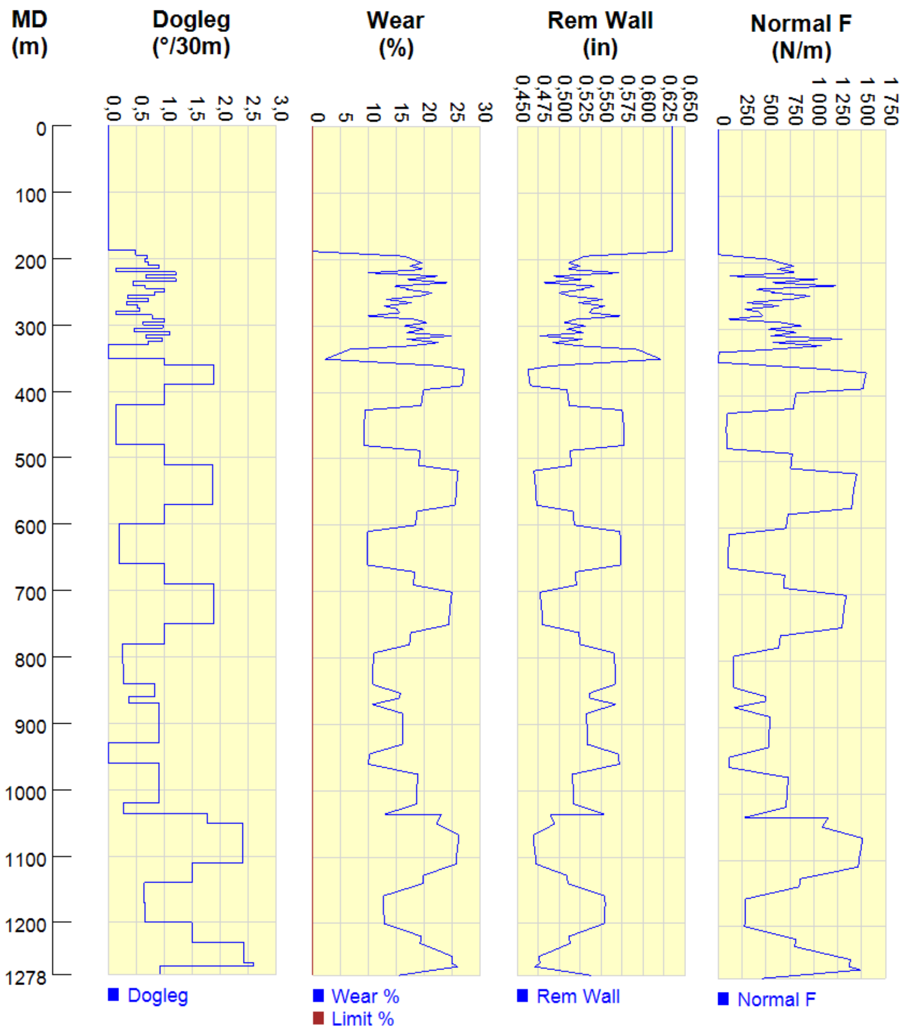


Figure 52: Casing wear 20" surface casing.

14" x 13 5/8" Intermediate casing

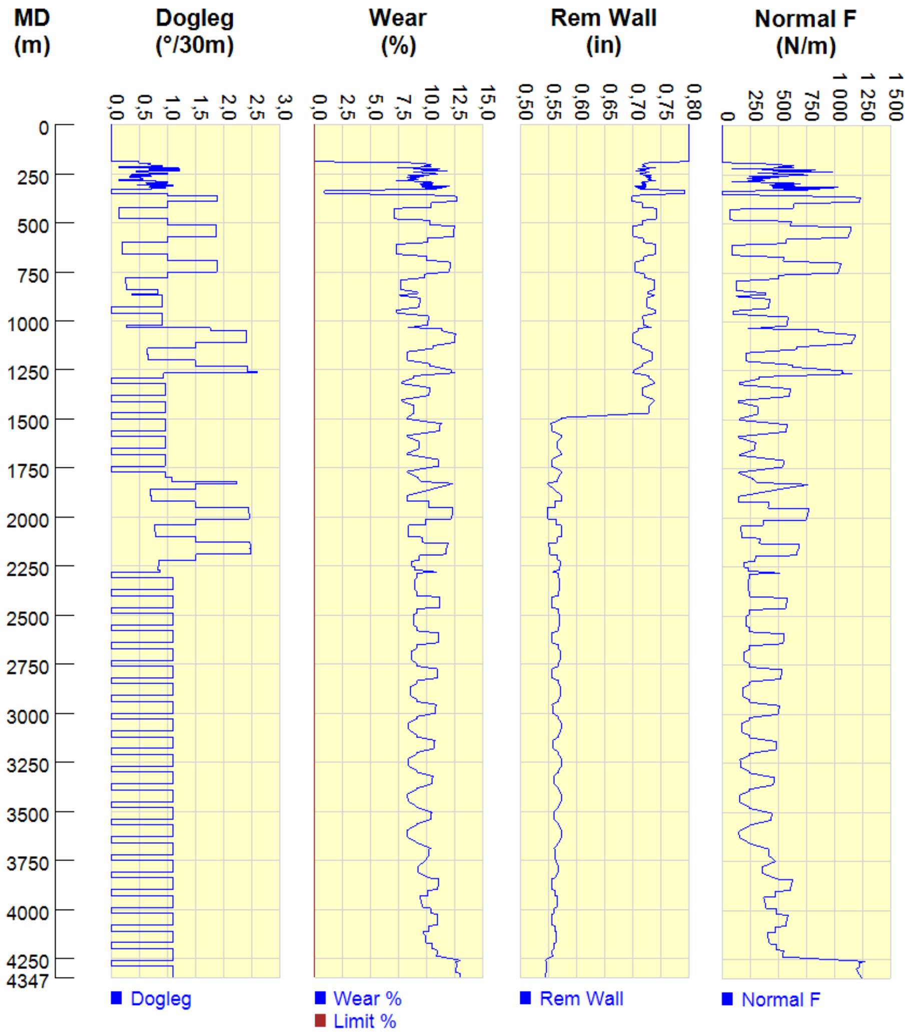


Figure 53: Casing wear 14" x 13 5/8" intermediate casing.

10 3/4" x 9 7/8" Production casing

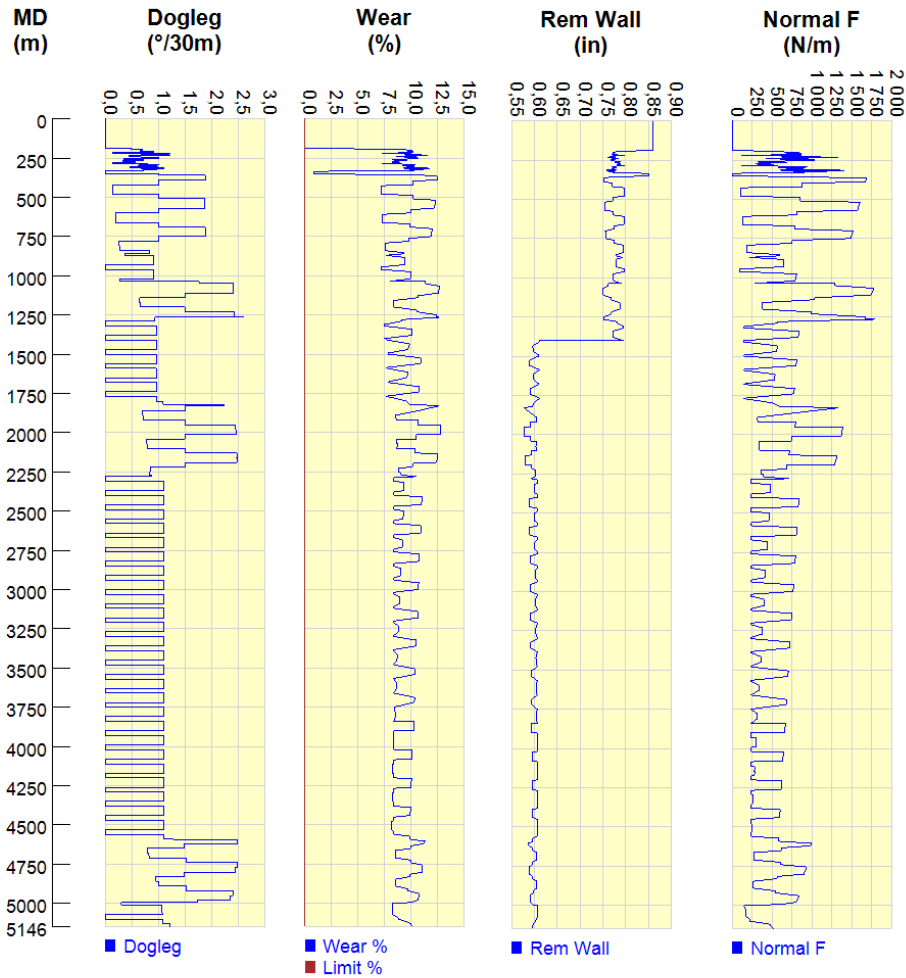


Figure 54: Casing wear 10 3/4" x 9 7/8" production casing.