MASTER THESIS

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ADVANCED TUBING DESIGN

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Preface

Developing this thesis for the past six months has been an exciting journey, dedicated to the last step in completing my Master of Science in Petroleum Engineering with a specialization in Drilling Technology.

This thesis is carried out during the spring semester of 2019 at the Norwegian University of Science and Technology at the Department of Geoscience and Petroleum. It was developed with background from my fall project ”Advanced packer analysis”.

Tubing design is a relevant subject within well design and is considered to be one of the most important aspects in order to make the well safe for operation. This thesis includes literature study and analysis of two wells modelled in the sofware WellCat^{TM}.

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Thanushina Tharmapalan

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I would like to thank and appreciate a number of wonderful individuals, who have been inspiring and supportive during this journey and making this thesis possible. I owe my deepest gratitude to my supervisor Bjørn Astor Brechan, for his excellent support and guidance during the period of developing this thesis. His long experience in the industry has given me a greater understanding of tubing design and good insight on discussion topics around this. Also, I would like to thank him for the training I got in the use of WellCat^{TM} in the specialization course before writing my fall project, followed by this thesis. Lastly, his enthusiasm and motivation have been helpful during all stages of this project.

My gratitude also goes to my fellow students for the wonderful times we have shared together the past five years at NTNU. Thank you for the great friendship, and for providing happy distractions outside the study and being a great support in deliberating over our problems and findings. These years would never have been the same without you and thank you for all the memories your presence helped me to create.

Finally, my deep and sincere gratitude to my family for the love and support they have given me throughout the entire process. Their motivating words have kept me driven to improve this thesis and to continue at tough points.

Summary

Phases in an oil production involve many physical elements, and one of the major components in an oil platform is the well. This thesis details the research and depth analysis of designing a tubing, which is the production pipe in a well.

When designing a well, the following must be considered:

- Tubing design, FEED (front end engineering design)
- Tubing size, which is one among many basic procedures for determining plateau production. This includes the size and the life span for the platform which consists of CPF (Central processing facility)
- Gas lift, protection of the DHSV (downhole safety valve) against scale and other issues related to well intervention
- Material quality to avoid corrosion and weakening or damage of the production pipe

These are one of the barrier elements in the primary barrier envelope and must therefore be intact to produce the well safely. Well integrity is a central element for the construction of the well, especially from the safety and economical aspect. An essential part of well integrity is designing the tubing and casing to fit the requirements for a well. When designing a well, tubulars will be selected based on the requirements and their exposure to loads throughout the lifecycle of the well.

All conditions and loads that occur during the operation of a well should be taken care of when designing the tubing. The tubing should have an acceptable margin for critical load cases that may affect well conditions. It should withstand burst, collapse, and tension stresses and be able to bear the weight of completion equipment. In addition, the tubing should resist corrosive fluids coming from the well. The tubing should help to produce the fluids from the formation in a safe manner without causing unconscionable operation problems.

This thesis looks detailed into tubing design and possible factors that may affect the tubing. This is achieved by designing two wells with different wellpaths and analyzing the difference. The modelling consists of forces from pressures, temperatures and fluids, and an illustration of how the tubing is exposed for each load case modelled. As packer affect the tubing in numerous ways, the resulting forces and packer envelope have been evaluated. The final analysis shows how tubing movement is caused by different load effects and how these are calculated in different softwares.

Sammendrag

Optimal oljeproduksjon krever god tilstrømning av hydrokarboner fra reservoaret til brønnen. Dette innebærer god brønndesign og en av hovedkomponentene i brønnen er produksjonsrøret. Produksjonsrøret transporterer olje og gass fra reservoaret gjennom brønnen på en trygg og kostnadseffektiv måte. Denne oppgaven gir en grundig forståelse og analyse av produksjonsrøret i en brønn.

Følgene faktorer er viktig å vurdere ved utforming av en brønn:

- Utkast av produksjonsrøret, som er et av de første elementene som bestemmes i tidlig fase

- Størrelse på produksjonsrøret som bestemmer underlaget for platå-produksjon, og som dimensjonerer levetid og størrelse på prosessanlegget

- Gassløft, beskyttelse av nedihullsventilen mot scale og andre behov for intervensjon

- Materialkvalitet for å unngå korrosjon og svekkelse av produksjonsrørene

Disse er et av barriere-elementene i primærbarrieren, og må derfor være intakt for å kunne produsere i brønnen. En god brønnintegritet innebærer sikre og gode barrierer i en brønn og er et sentralt element for utformingen av brønnen. Designingen av produksjonsrøret og foringsrøret er en viktig del av brønnintegritet som må ivaretas for å oppfylle kravene til en brønn. Rørene bestemmes ut ifra kravene og deres eksponering for belastninger i brønnens livssyklus.

Når produksjonsrøret skal utformes, bør alle forhold og belastninger som er mulig å oppstå under drift og vedlikehold tas i betraktning. Røret skal kunne bære vekten av forskjellige kompletteringsutstyr, samt ha en akseptabel margin for mulige kritiske belastninger som kan påvirke boreforholdene. Røret må bidra til en sikker og effektiv produksjon, samtidig motstå mulige korroderende væsker fra reservoaret.

Denne oppgaven utdyper designet av et produksjonsrør og ulike faktorer som kan påvirke røret. To brønner med forskjellige brønnbaner har blitt modellert og mulige belastninger i rørdesignene har blitt simulert. Modelleringen består av krefter fra trykk, temperatur og væsker, og en visualisering av hvordan røret er eksponert for hver last som er modellert. Produksjonspakningen påvirker produksjonsrøret på mange måter og derfor er resulterende krefter og pakningskonvolutt blitt evaluert. Den endelige analysen viser hvordan rørbevegelse påvirkes av ulike belastningseffekter og hvordan disse beregningene er utført i forskjellige programvarer.

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Abbreviations

API	American Petroleum Institute
BHP	Bottomhole pressure
CPF	Central processing facility
DF	Design factor
DHSV	Downhole safety valve
FC	Final condition
FEED	Front end engineering design
HPHT	High pressure high temperature
IC	Initial condition
ID	Inner diameter
IPR	Inflow performance relationship
OD	Outer diameter
PVT	Pressure, volume, temperature
SF	Safety factor
TOC	Top of cement
VLP	Vertical lift performance relationship
WBS	Well barrier schematic

Chapter 1

Introduction

Completion design involves some of the most complex engineerings in well construction. Only a few software tools on the market are able to model tubing design and fewer still can design HPHT and ultradeep wells. The forces during the production phase comprise some of the highest in the life cycle of a well. Large temperature variations often result in thermal expansion, ballooning and annular fluid expansion (AFE). These effects are proportional to the temperature changes. The resulting stress often set the premises for the minimum design for the upper completion equipment. The following figure shows a basic well schematic with all casings and the production tubing which is marked in blue. The production tubing is placed as the innermost tubular and the production packer is placed in the annulus, between the production casing and the tubing string.

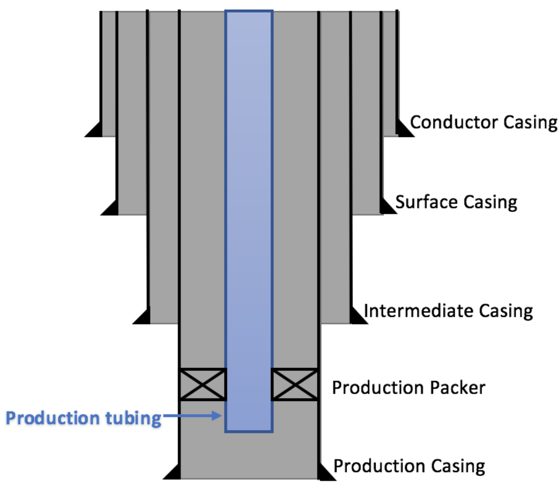

Figure 1.1: Basic illustration of casing and tubing schematic in a well

One critical task for engineers is to carefully decide which type of casing or tubing to select in order to properly design a completion to meet the objective of each well. As reservoir properties directly influence equipment in the well, they have to be considered safe. Reservoir properties can be categorized as rock and fluid properties. In terms of rock properties, the most essential factors to focus on are permeability, formation temperature, formation pressure and formation strength. For the fluid properties, the type of reservoir fluid, H_2S content, PVT of reservoir fluid and CO_2 content will be the main elements to consider, DrillingFormulas (2016d).

The production tubing needs to be strong enough to withstand all production loads and to be able to do workovers in the later stage of the well. This is mainly because all completion equipment runs through the tubing string, which again requires the tubing design to be optimal. The tubing is used to conduit oil, gas or water from the reservoir, in addition to protect the casing from deposit, wear and corrosion from the reservoir fluids in the formation. Tubing practice and assumption behind tubing design is further discussed when design limits are evaluated. Tubing design is essential as it is the foundation of well integrity which ensures good production of oil in the well.

1.1 Equipment selection

Upper completion in a well should contribute to good well control. The equipment that is installed in the upper completion of a well will help to carry the flow from the reservoir to the surface inside the pipes and maintain well control. This ensures unwanted outflow from the well. Some of the essential equipment in an upper completion is also a part of the primary barrier in a producing well. These are production tubing, production packer, downhole safety valve (DHSV) and are further explained in detail in the sections below.

1.1.1 Tubing size

For a well completion process it is essential to determine tubing, production casing and hole sizes. The first step would be to choose the design of the hole structure and production casing. After well completion operations have been planned, the tubing size and the production mode is decided based on the production casing.

To have a trouble-free and efficient operation of the fluid system; selection of good material, type and size of tubing is critical. It is depended on the well operation and fitting requirements of each well. To select the proper tubing, it is essential to safely consider right material and optimum tubing size. For the tubing, this particularly means the OD, ID and wall thickness.

For instant, a small tubing may cause high fluid velocity, which can have negative side effects like damaged pumps. “In pressure lines, it causes high friction losses and turbulence, both resulting in high pressure drops and heat generation”, ihservice (2019). Moreover, a high heat generation will result in low efficiency by wasting energy. Contrarily, a too large tubing may cause an increase in system cost. This explains why an optimum tubing size is critical at any point.

The procedure for determining tubing size can be explained in simple steps. Step one is to determine the required flow diameter. This is done by estimating the required flow rate and type of line in the tubing. In the next step, the tubing OD and wall thickness is determined. This has to be fulfilled with two conditions, ihservice (2019):

Condition I:

$$\text{Recommended Design Pressure} \geq \text{Maximum Operating Pressure}$$

Condition II:

$$\text{Tubing ID} \geq \text{Required Flow Diameter}$$

Tubing performance is the behavior of a producing well in an installed tubing. The flowing bottom hole pressure (BHP) for a well can be calculated by a vertical flow equation. For a gas well, Katz has presented the following equation only valid for dry gas, Brechan (2019):

$$\mathrm{q_g} = 200000\left(\frac{\mathrm{sD^5(P_{wf}^2 - e^sP_{wh}^2)}}{\mathrm{G_g\overline{TZ}Hf(e^s - 1)}}\right) \tag{1.1}$$

where,
q_g = gas flow rate
D = tubing diameter
P_{wf} = bottomhole flowing pressure
P_{wh} = wellhead flowing pressure
G_g = gas gravity
$\overline{T}$ = average temperature
$\overline{Z}$ = average gas comparability factor
H = vertical depth
f = friction factor
e = absolute pipe roughness
s = $0{,}0375G_gH/\overline{TZ}$

There are similar equations for oil and mixed phase (combination of oil and gas) which are used when determining flow rate for these fluid types.

Tubing diameter can also be determined by using different charts and combining results from expected flow or production rates in a well. Chart **1.2** shows the well flowing bottom hole pressure, Pwf, on the y-axis and the production rate on the x-axis. Pwf defines the pressure range between the atmospheric pressure and average reservoir pressure. The tubing diameter can then be selected depending on the IPR (inflow performance relationship) and VLP (vertical lift performance relationship), also called outflow. IPR describes the flow in the reservoir, while VLP describes the bottom hole pressure as a function of flow rate. The vertical lift performance depends on factors like the fluid's PVT properties, tubing size, well depth and etc, Technology (2017).

The intersection between the VLP and IPR curves, gives the deliverability of the well. It is called the operating point and expresses the actual production for a given condition. This will in addition to other factors help find the appropriate tubing size, Technology (2017). The chart below shows the deliverability of a high rate gas well with different range of tubing sizes.

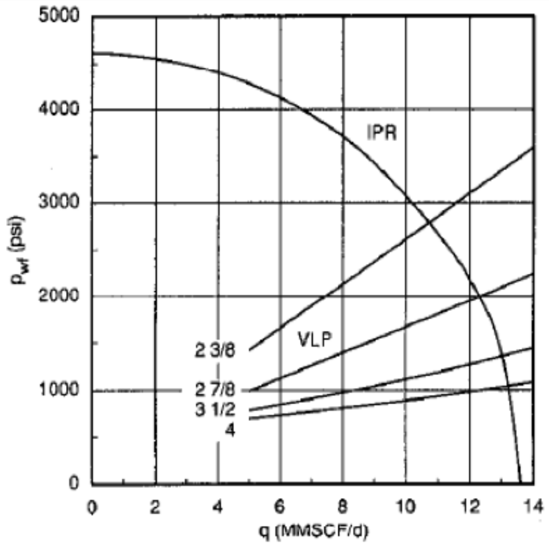

Figure 8-10
Deliverability from a high-rate gas well with a range of tubing diameters.

Figure 1.2: Deliverability for a high rate gas well with a range of tubing diameters. The chart shows well flowing bottom hole pressure, Pwf, as a function of production rate, q, Brechan (2019)

Choice of tubing size mainly depends on desired production rate as discussed above. Production rate depends on factors like:

- Inflow performance relation
- Pressure drop in tubing
- Pressure drop through the flow line
- Static reservoir pressure
- Pressure drop through the well-head constrictions
- Pressure level in the surface separating facilities

When selecting tubing ID, it is essential to look into expected production rate, but also at completion method and the further needs to conduit fluids from the reservoir. When designing a well, determination of tubing is one of the first steps to take into account. To determine the inner diameter of the production tubing it is essential to go deeply into IPR, VLP, choke performance and horizontal flow performance. These steps will give a well performance evaluation, which can help finding the right tubing size and flow line, Equipment (2008/2009).

Inflow performance relationships (IPR):
The inflow performance relationship is the "ability of well to produce fluid against various bottomhole flowing pressures, Pwf". It also gives the relationship between the flow rate and the drawdown. Drawdown defines the difference between the average reservoir pressure and flowing bottomhole pressure ($P_R - P_{wf}$). The shape of the IPR curve depends on the drive of the reservoir. The curve "[...] declines with cumulative production and with formation damage", Equipment (2008/2009).

Verical lift performance relationship (VLP)/ Outflow:
"Calculation of pressure losses in vertical/deviated wells can be performed from correlations based upon lab mechanistic models". Pressure gradient curves, also called traverse curves are determined based on where pressure losses are found, Equipment (2008/2009).

Horizontal flow performance:
As for the vertical flow performance, it is possible to calculate pressure losses in horizontal pipes. This is done from correlation-based models. The traverse curves are obtained the same way as for the VLP curves, Equipment (2008/2009).

Choke performance:
During a wells lifetime, different chokes will be installed in the well. For that reason, it is important to look at the choke performance when selecting tubing size. These chokes are installed to "1. Control pressure for safety, 2. Allow desired rate, 3. Prevent sand entry to surface facilities, 4. Control water and gas coning, 5. Prevent press surges downstream", Equipment (2008/2009).

1.1.2 DHSV - Downhole safety valve

Down hole safety valve is a "downhole device that isolates wellbore pressure and fluids in the event of an emergency or catastrophic failure of surface equipment", Schlumberger (2019b). It is a valve that is mounted in the upper part of the well in the production tubing. The valve is kept open by pressure, through a control line. The down hole safety valve closes if the pressure in the control line falls below a minimum level. This equipment is part of the primary barrier envelope in a producing well.

The device is a flap valve that is installed to prevent oil or gas from flowing to the surface when it is closed. "[...] It must be installed at least 50 meters below the seabed. It is nevertheless common to be placed several hundred meters deep in the Norwegian shelf". The valve is operated using hydraulic control lines, often called a fail-safe-close valve. This means that if the pressure in the control line falls below the limit value, the flap will close automatically. The down hole safety valve must be regularly tested for function as long as the well produces. In addition, it should be tested after well maintenance has been done. “All testing must be in accordance with the requirements of NORSOK”, Aabø (2017a).

DHSV is usually formed as a flapper valve, but can also be a ball valve. “The valve is open when the flap is pressed against the tubing wall and closed when the flap is closed against a seat in the inner diameter of the tubing” .. The flap will close when there is wellstream coming from below. It is controlled by a hydraulic pressure-controlled piston pushing a spring together. “If the hydraulic pressure disappears, the spring will push the valve to the closed position”, Aabø (2017b).

1.1.3 Selection of production packer

To select the right production packer for an optimum well completion design, three major issues

- Fit, form and functioning of the tool
- Metallurgy
- Elastomeric material and seal design

have to be considered carefully.

All well completion operations need to be developed based on each field with its own requirements. It is essential to identify well integrity and maintenance to have a good well design. For production packer, it is important to design a fit, form and good functioning equipment, as it can affect the tubing movement calculation, and consequently influence completion design.

For completion equipment like production packer, there are many factors which are considered when determining the metal type. “These include mechanical properties/strength and corrosion embrittlement, or stress cracking resistance”. It might be uneconomical and in many cases it is more optimal to select different material for the tubing and accessories like production packer. “For example, material strength derived from cold work may not be available in the large diameters, which is required for some accessories”, Brechan Bjørn A. (2017). Environmental data that involves type of well (oil or gas), bottom hole pressure and temperature, reservoir fluid type, tubing grade, corrosion history is some of many factors to consider when making material recommendations.

When it comes to elastomeric or plastic materials, it is essential to know the expected maximum and minimum temperatures at sealing areas since these are the most critical one. “Inhibition programs and anticipated acid treatment programs should be considered during the completion design stage. Completion fluids can adversely affect seal materials", Brechan Bjørn A. (2017). After pressures, fluids, temperatures, and chemical data is known for the particular well, the work with seal applications in the tool design can be continued.

The understanding of packers and the knowledge of available packer types in the market helps to select the right production packer. "A packer creates a seal between the tubing string and the casing string, or in the case of an open hole completion, packers seal against the formation", Brechan Bjørn A. (2017). The four major reasons why packers are needed are:

- To maximize safety and control
- To protect the casing string
- To improve productivity
- To conserve energy

As production packer is placed in the annulus, between the tubing and the casing, it isolates and protects the casing from high pressures and corrosive fluids from the well. This is important because the casing is cemented in place and can be expensive or difficult to replace. "The packer may also be plugged, isolating the wellbore from the formation during workover operations up the hole", Brechan Bjørn A. (2017). There are several types of packers which can be selected by the requirements and needs of each well. This needs to be investigated before selecting the correct one for the particular well.

To select an optimum packer, an examination of well conditions and capacities of the operation possibilities are required. It is easier to find correct packer design for the correct conditions, rather than selecting the packer features, and then fitting the requirements. The operations that has to be considered when selecting the right production packer, can be divided into three major categories:

- Production and treating
- Running, setting and tubing space-out
- Retrieving

The production packer should be placed in an area where there is approved cement behind the casing. The packer is screwed together with the production tubing and must be placed at the bottom of the upper completion. It should prevent liquid and gas from flowing outside the production tubing and anchor the tubing to the casing. It should be set quite far into the well, ranging from 1500 meters to several thousand meters below the seabed, as it is placed far down in the production casing.

As discussed above, the positioning of the production packer is very important and therefore it should be located in a cemented area. This means that the packer is located far down in the well, close to the reservoir where formation strength exceeds formation pressure. "If a poor cement bond exists in the interval in which the packer is to be set, the packer's ability to serve as a barrier may be compromised should a leak in the casing string occur", SPE (2017a). This leads to the cement and the casing in this area to be included in the primary well barrier envelope.

1.2 Material selection and corrosion considerations

The importance of selecting the right completion equipment and tubing size is equivalent when considering the material for the equipment. The choice of material are based on environmental conditions, corrosivity of well fluids, maximum and minimum temperatures and pressures, safety aspects and cost. The steel quality have to withstand the loads that come from well fluids, tensile, twisting, change of length and bending forces.

Corrosive environments are critical elements when selecting the material for the tubing. The tubular string can be damaged by corrosion from both inside and outside. "Acidity caused by the presence of acid gases (CO2 and H2S) normally increases the corrosion rate". It is common to follow the API standard practice grades, and if corrosion becomes a problem, batch treatments can be used to control or reduce the effect of corrosion. For steel tubings, corrosion can be a major problem and it will mostly occur where there are high rate gas condensates containing CO_2. "The CO2 attacks the steel tubing, which creates an iron carbonate film (corrosion product); it is removed from the wall by erosion (impingement of well fluids)", SPE (2017b). This may require frequent batch inhibition to protect the tubing string.

Metals which are unlike each other and placed close to each other can influence corrosion. "Plastic internal coating of a tubing string is sometimes used to deter corrosion or erosion in oil and gas wells and may increase tubing life significantly", SPE (2017b). "Some practices for corrosion control involve cathodic protection, chemical inhibition, chemical control (removal of dissolved gases such as hydrogen sulfide, carbon dioxide, and oxygen), oxygen scavenging, pH adjustment, deposition control (for example, scales) and coatings", Schlumberger (2019a). However, when the bottomhole temperature is high, ranging from 400 to 500 ^{o}F corrosion control can be extremely difficult.

There is no exact solution or simple resort to control corrosion as it can appear in different forms depending on the environment. It is therefore important to treat each tubing in a well individually. To solve a corrosion problem one can attempt to understand the operation conditions and environmental factors.

1.3 Well integrity and tubing as primary barrier envelope

Well integrity is defined by NORSOK (2013) Standard D-010 as "application of technical, operational and organizational solutions to reduce the risk of uncontrolled release of formation fluids throughout the life cycle of a well". By maintaining full control of fluid within a well at all times, loss of containment to the environment and unintended fluid movement can be prevented. Well integrity also refers to a policy about commitments and obligations to safeguard health, safety, environment, assets, and reputation, Juarez (2018), NORSOK (2013).

“WBS shall be prepared for each well activity and operation”, NORSOK (2013). Barriers in wells should ensure the external environment against leakage of hydrocarbons. Two separate barriers are divided into primary and secondary barrier. When hydrocarbons are produced, large amounts of high-pressure hydrocarbons flow out of the reservoir and up to the production platform or into pipelines. The external environment must be protected against leaks of these hydrocarbons. It is done by using barriers placed in the well. The requirements for the barriers and barrier elements are described detailed in NORSOK standard D-010. The suppliers of the components ensure that the equipment meets the requirements, and often the equipment is better qualified than the minimum requirement.

Barriers in several different well situations with illustrations shows the primary barriers and secondary barriers in NORSOK (2013). The figure below shows one example of a producing well, which is shut-in. The primary barrier envelope is marked in blue, while the secondary barrier is marked in red in figure **1.3**.

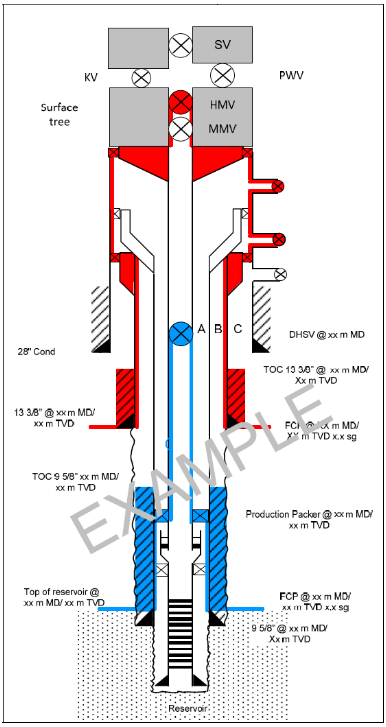

Figure 1.3: Primary well barrier marked in blue and secondary well barrier envelope marked in red, NORSOK (2013)

The primary barrier envelope consists of components in the completion string for upper completion which are the production tubing, DHSV, production packer in addition to the casing and cement in which the production packer is located. If there is a side pocket with a valve for a gas lift in the completion, the well should also have an annular safety valve (ASV). ASV prevents outflow of gas on the outside of the production pipe and is then a part of the primary barrier. All these components form the wall of the primary barrier envelope.

From the production packer the primary barrier in the production pipe will be continued for the upper completion. The threads in the production pipes must be gas-tight so that gas does not leak outside of the production pipe. The production pipe should be able to withstand length change due to pressures and temperature variations in the well and be able to bear weight and the entire completion. Moreover, the tubing should be tested when the upper completion is installed in the well. In the completion, other components which have been introduced should be installed with the same requirements for strength and threads as the production pipe.

1.4 Thermal effect

For a producing well, temperature prediction of production fluids and temperature changes in surrounding tubing is critical when producing and completing. These can be analyzed by tubing stress analysis with different load cases, material selection and prediction of the flow in the tubular string. The tubing string will be subjected to various loads throughout its lifetime in the well. During operations in the well and production phase, changes in temperature may occur.

Temperature change causes steel to contract or expand. Contraction of the tubing happens when cold fluids are injected into the tubing. On the other hand, thermal expansion of steel happens when hot formations produce fluids. Typically the deeper the formation, the higher is the temperature of the fluid. Also, the heat capacity of produced fluid influences the temperature difference, ΔT.

If the tubing is free to move, the length of tubing will either be longer or shorter due to thermal effects. If the tubing string is anchored, there will be a change in axial force due to temperature effect. The axial force generated by the change in temperature and can be described by the following equation:

$$F_{temp} = C_T E A_s \Delta T \tag{1.2}$$

where,
F_{temp} = axial force generated by change in temperature (force in tubing)
C_T = thermal expansion coefficient
E = Young's modulus
A_s = cross sectional area of tubing = $A_o - A_i$
ΔT = average temperature change from initial condition to final condition

From equation (1.2) it can be observed that cooling will lead to tension and heating will lead to compressional force on the tubular string. Equation (1.3) describes the length change due to thermal effects.

$$\Delta L_{temp} = C_T \Delta T L \tag{1.3}$$

where,
ΔL_{temp} = length change due to thermal effects
L = length of tubing
Figure **1.4** and **1.5** shows an illustration of length changes due to different thermal loads.

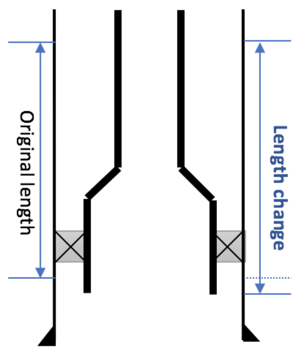

Figure 1.4: Tubing is lengthen by temperature increase

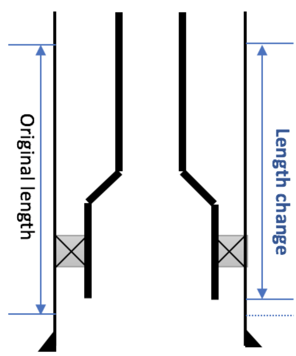

Figure 1.5: Tubing is shorten by temperature decrease

There are several heat transfer mechanism which takes place in a producing well. This is explained by a simple figure:

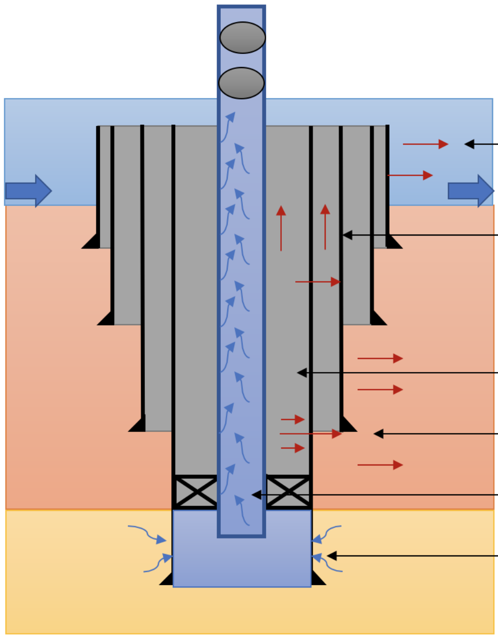

Figure 1.6: Figure explaining heat transferring mechanism in a well

Conduction is simply described as the transfer of heat through physical contact. “The heat transfer occurs at a molecular level, when the heat/energy is absorbed by a surface and causes the molecules of that surface to move more quickly”, Brechan (2017). Conduction can take place in all phases, such as in liquids, solids, and gases. The heat flow appears within the body where the heat transfer happens. The empirical law of heat flux, Fourier (1878) is positive in the direction of energy flow, i.e. going from high to low temperature.

$$q_x = -k\frac{dT}{dx} \tag{1.4}$$

where,
q_x = the heat flux in x-direction per unit area [Btu/hr ft2]
k = thermal conductivity [Btu/hr ft F]
A =Area of plane the heat moves through [ft2]
dT/dx = temperature gradient [F/ft]

Liquids have higher molecular density, which leads to more molecular interactions. Hence, liquids are more effective as conductors compared to gasses. Solids have a molecular structure which is organized as a lattice so the waves can be induced by atomic motion.

Convection can be explained as heat or energy transfer by random molecular motion and/or by mass motion of the fluid. It can happen either forced or natural. “Natural convection occurs when the drive is e.g. buoyancy or temperature, and forced convection would be caused by external means as e.g. a pump or a fan”, Brechan (2017). The heat flux for convection, regardless if the heat transfer is forced or natural can be described according to Newtons’s law of cooling, Incropera (2007):

$$q_x = hA(T_S - T_\infty) \tag{1.5}$$

where,
h = average heat transfer coefficient [Btu/hr ft F]
T_S =Temperature of the surface / body [F]
T_∞ = Temperature of the flowing fluid [F]

When fluid goes through a tubular, it causes heat transfer between the fluid and the pipe. This heat transfer occurs because of the difference of the fluid and geothermal temperature. Thus, good knowledge about heat transmission which occurs during production, drilling and injection operations in a well is necessary.

1.5 AFE - Annular fluid expansion

Thermal expansion may change properties of the fluid by either increase the volume or the pressure of the fluid. This issue is respectively called annular fluid expansion, AFE or annular pressure build up, APB. AFE can especially be a problem when wells are placed in deepwater, for subsea wells or when a well is exposed for heat. “In subsea wells, the casing annulus cannot be accessed once the casing hanger is landed and in this case, the annulus fluid expansion pressure must be considered during casing design”,Juarez (2015).

When looking at APB, three major factors interact. Firstly, an increase in temperature causes fluid expansion. This can be seen as the driving force behind the pressure build up. Secondly, ballooning and reverse ballooning of the casing string may change containment volume. Lastly, by removing fluid from the annulus, APB may occur. This can, for example, happen when there is leakage through an open shoe or when bleeding off at the surface, Bellarby (2009a). When looking at the pressure increas, it will also influence the axial load profiles, especially in the casing and tubing string for pressure ballooning effects, Juarez (2015). The factors to take into account when annular fluid expansion occurs is explained in figure **1.7**.

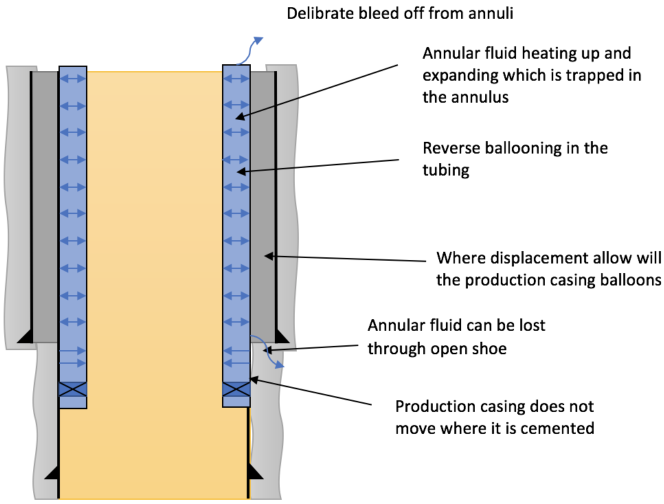

Figure 1.7: Annulus fluid expansion showing the A' annulus with explanations

Annular fluid expansion and annular fluid contraction are phenomena that can have a significant influence on the tubing and casing design. For installed equipment in the well, AFE and AFC will act as an additional load and is caused by temperature variation in the well. After the well is installed and exposed to initial forces, the well will be exposed to the given loads. This will eventually give AFE and AFC and may change final conditions.

Chapter 2

Theory - Part I

The engineering of upper completion comprises the following main elements and calculations:

- Acting forces
  - $\rightarrow$ Modelling of forces from formation pressures and temperatures (load cases)
  - $\rightarrow$ Resulting forces on packer
  - $\rightarrow$ Tubing-to-casing drag
  - $\rightarrow$ Different load effects on tubing
- Design strength of tubing
  - $\rightarrow$ Selection of tubing grade
  - $\rightarrow$ Combined loads - Triaxial load capacity diagram
  - $\rightarrow$ Packer envelope
  - $\rightarrow$ Buckling

The following chapters will further go into detail on each element listed above.

2.1 Acting forces

The tubing string will be subjected to various loads throughout its lifetime in the well. During operations in the well and production phase, changes in temperature and pressure occur in the tubing and annulus. If the tubing string is free to move, changes in temperature, density and pressure will cause a change in length. If it is not permitted to move, the forces will be generated in the tubing. Moreover, these forces will act on the packer and wellhead to prevent these length changes from occurring, Bellarby (2009a). The production packer is exposed to a multitude of forces. “The tubing will transmit axial forces to the production packer when it is heated and/or pressurised”, Bellarby (2009a).

2.1.1 Modelling of forces from formation pressures and temperatures (load cases)

For tubing design and load calculations, tension and temperature are significant factors that have to be considered. The packer type, packer load, seal length, and buckling is likewise essential. Tubing loads are affected by changes in different conditions like internal fluid density (tubing), surface pressure in tubing, external (annular) fluid density, surface pressure in annulus and temperature profile. All these conditions are characteristic variables that denote loads in the tubing. The tubing string is run at initial conditions of pressures, densities and temperatures. The initial condition is the moment at which annulus is isolated from the perforation. After the initial condition; densities, pressures and temperatures changes. These changes generate loads on tubing or load combinations. "Both axial and pressure loads are created by these changes", Partners (2019).

There are different type of packers which will affect the tubing in different ways. One is free motion packer. Here will the tubing in the seal bore be able to move freely up or down. Limited motion packer where tubing in the seal bore can move freely upward only. While the no motion packer where the tubing in the seal bore is not able to move. Figure **2.1**, **2.2** and **2.3** respectively shows an illustration of free motion, limited motion and a no motion packer.

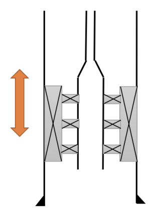

Figure 2.1: Free motion packer

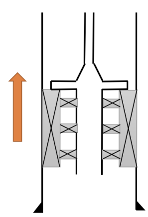

Figure 2.2: Limited motion packer

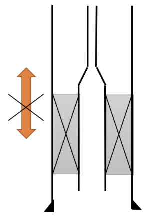

Figure 2.3: No motion packer

The following table represent typical values and parameters used to decide initial and final condition.

Table 2.1: Typical parameters for initial condition (IC) and final condition (FC)

	IC		FC
Parameter	**Symbol**	**Typical Design Value**	**Symbol**
Density inside(tubing)[ppg]	$\rho_{\mathrm{i,init}}$	Packer fluid density	$\rho_{\mathrm{i,f}}$
Density outside(annulus)[ppg]	$\rho_{\mathrm{o,init}}$	Packer fluid density	$\rho_{\mathrm{o,f}}$
Surface pressure inside(tubing)[psi]	$\mathrm{ps}_{\mathrm{i,init}}$	Zero	$\mathrm{ps}_{\mathrm{i,f}}$
Surface pressure outside(annulus)[psi]	$\mathrm{ps}_{\mathrm{o,init}}$	Zero	$\mathrm{ps}_{\mathrm{o,f}}$
Average temperature [°F]	$\mathrm{temp}_{\mathrm{avg,init}}$	Geothermal	$\mathrm{temp}_{\mathrm{avg,f}}$

It is in rare cases that fluid density in the tubing string differs from the annular density. Surface pressure is zero most of the time and is the same for the tubing and annulus. An exception can occur when there are snubbing operations. The average temperature is decided based on the geothermal gradient for the initial condition, while the temperature profile is used for the final condition.

Initial conditions

Initial condition is one of the most important load cases, as all other loads are calculated relative to this. It can therefore also be called the base case. A base case that appears to be incorrect, ensues incorrect output for the other load cases. As a result, it is important to get the pressures and temperature correct for each load cases applied.

The initial condition is defined when packers have been set and the setting pressures have been released. When setting on the completion run, the movement of the packer is included. "The initial condition should take account of any difference in fluid gradients between the annulus and tubing fluids", Bellarby (2009a). The temperature in the initial condition is not always the same as the geothermal gradient, because the circulating operations prior to setting the completion can make a change in temperature. This can for example be thermal effects which may cause changes in the tubing.

Tubing pressure test

A tubing pressure test is testing the tubing before doing completion setup. “Many companies stipulate that the tubing pressure test should be 10 percent greater than the maximum tubing pressure differential during service loads”, Bellarby (2009a). The pressure test is applied with plugs included or without plugs set in place, before or after the tubing string has been set or landed with packer included. If the plug is included in a pressure test, the test will consider effects as if the plug is leaking and the pressure being applied below the plug.

Annulus pressure test

The main goal of the annulus pressure test is to verify the integrity of the packer or tubing hanger. It should mainly be tested with the same criteria as a tubing pressure test. This is to include the scenario of the tubing leak during a service load. The purpose of doing a pressure test in the A-annulus is to certify the secondary well barrier, NORSOK (2013).

Production

“In general, production-related conditions induce thermal changes in a well and may generate high-temperature loads with either high or low pressures in the tubing”, Bellarby (2009a). Temperature is depended on the fluid, flow rate and pressure in the well. Considerations like the highest load case with the highest temperatures, loads with high surface pressures, high collapse loads and a separate load case made for tubing evacuation have to be made for production-related conditions. An example of a production load is the production early stage in a well, called ”Early Stage Production”. In this particular load case, the flow rate is high and friction is included in the calculations. Furthermore, tubing is subjected to thermal loads as production will cause an increase in temperature that comes from production fluids and warmer surroundings, Bellarby (2009a). This will again heat up the annulus and cause an annular fluid expansion which is described in the previous chapter.

Shut-in

During an emergency shutdown situation, shut in the well on command will prevent hydrocarbons from flowing from the well. When the well is shut-in, both the pressure and temperature can be high. The two main shut-in cases are called long-term shut-in and short-term shut-in. In long-term shut-in, will the well cool down fully until it reaches the geothermal gradient. This case is normally not required, “[...] as this will have the same temperature and lower pressure than a tubing pressure test case”, Bellarby (2009a). The worst-case scenario is when there is high-temperature steady state production followed by a quick shut-in, as this will lead to high pressures and temperatures.

2.1.2 Resulting forces on packer

Forces on packer

Free body diagram is used to identify all forces that are applied to the tubing, casing or packer. This is done by drawing simplified figures of the system, and then add the loads that are acting on the components. Figure **2.4** shows a sketch of the basic geometries of a production packer set in a well.

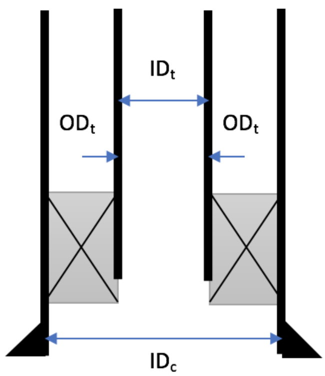

Figure 2.4: Simplified sketch of a packer in a well with tubing and casing

where,
ID_t = inner diameter tubing
OD_t = outer diameter tubing
ID_c = inner diameter casing

Figure **2.5** shows the forces acting on the production packer and where these are located:

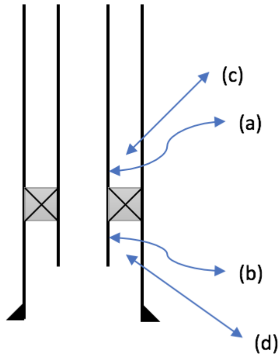

Figure 2.5: Simplified sketch of forces acting on the packer

where,
(a) represent the axial stress above the packer
(b) represent the axial stress below the packer
(c) represent the annular pressure above the packer
(d) represent the annular pressure below the packer

For a static system, Newton's 3rd law is used. Here the loads are summed and set equal to zero.

$$\mathrm{F} = \mathrm{p} \cdot \mathrm{A} \tag{2.1}$$

$$\sum \mathrm{F_y} = 0 \tag{2.2}$$

where,
F = force
p = pressure
A = area
$\sum \mathrm{F_y}$ = sum of forces in y-direction

WellCat forces

WellCat analysis and models three packer forces:

1. Tubing-to-packer force
2. Packer-to-casing force
3. Latching/Pinning force

Tubing-to-packer force

Tubing-to-packer force is the total axial force transferred from the tubing and the hydrostatic pressure on the cross section of the tubing. "The tubing-to-packer loads will be the difference in axial load from immediately above the packer to immediately below the packer", Bellarby (2009a).

Tubing-to-packer force can then easily be estimated by the following equation

$$\text{tubing-to-packer force} = \text{axial force below packer} - \text{axial force above packer} \tag{2.3}$$

The drawing below shows where the forces are acting:

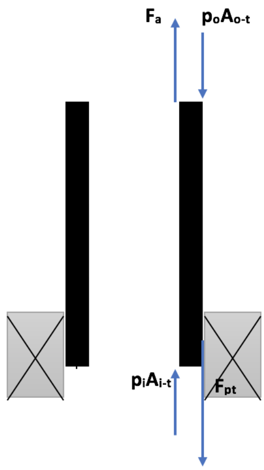

Figure 2.6: A simplified sketch of how forces are transferred from the tubing to the packer

By using Newton's third law, tubing-to-packer force is derived:

$$\sum F_y = 0 = p_i A_{i\text{-}t} - F_{pt} - p_o A_{o\text{-}t} \tag{2.4}$$

$\Longleftrightarrow$

$$F_{pt} = p_i A_{i\text{-}t} - p_o A_{o\text{-}t} \tag{2.5}$$

where,
p_i = hydrostatic pressure acting from below tubing/packer
$A_{i\text{-}t}$ = inner area of tubular = $\frac{\pi}{4}ID_t^2$
F_{pt} = tubing-to-packer force
p_o = hydrostatic pressure acting from above packer
$A_{o\text{-}t}$ = outer area of tubular = $\frac{\pi}{4}OD_t^2$

Packer-to-casing force

Packer-to-casing force is simply the axial force in addition to the hydrostatic pressure on the packer bore area and tubing cross section. The packer-to-casing force is simply then:

$$\text{packer-to-casing force} = \text{tubing to packer force} + \\ (\text{pressure above packer} - \text{pressure below packer}) \cdot (\text{inner diameter casing} - \text{outer diameter tubing}) \tag{2.6}$$

Figure **2.7** shows how the forces are acting:

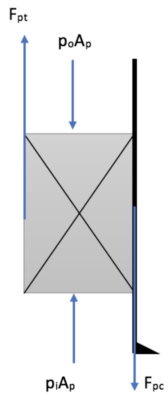

Figure 2.7: A simplified sketch of how forces are transferred from the packer to the casing

By using Newton's third law, packer-to-casing force is dervied:

$$\sum F_y = 0 = F_{pt} + p_i A_p - p_o A_p - F_{pc} \tag{2.7}$$

$\iff$

$$F_{pc} = F_{pt} + p_i A_p - p_o A_p \tag{2.8}$$

$\iff$

$$F_{pc} = F_{pt} + A_p(p_i - p_o) \tag{2.9}$$

where,
F_{pc} = packer-to-casing force
A_p = packer bore area= $\frac{\pi}{4}(ID_c^2 - OD_t^2)$

Latching/Pinning force

Latching force, as it is called in WellCat, also known as pinning force is the sum of the forces acting on the seals and axial load above the packer. Latching forces can be estimated by the following equation:

$$\text{latching force} = \text{internal pressure} \cdot (\text{seal bore ID} - \text{tubing ID}) \tag{2.10}$$

On an anchored tubing, the forces will transfer to points in the well like the production packer or the wellhead. The main problem on the wellhead will be wellhead growth. This will happen when the tubing is under compression at the tubing hanger. Meanwhile, the production packer will be subjected to both tension and compression throughout the well completion part. Therefore it is as mentioned an important element in the primary barrier envelope and has to be considered carefully.

2.1.3 Tubing-to-casing drag

“Drag opposes tubing movement and transfers axial loads to the casing”, Bellarby (2009a).

Contact force(F_n) between tubing and casing is caused by three main factors:

1. Forces from buckling
2. Forces due to gravity
3. Forces due to the capstan effect

1. Is caused by the contact force with the casing. The larger the buckling is, the greater the contact force is.
2. For a deviated well, this force is generated by the tubing weight which acts onto the casing. While for a horizontal well, all of the buoyed weight will be transferred and cause this force.
3. This effect is due to tubing passing through doglegs. A contact force will be generated when the tubing is in tension and results the tubing to be pulled onto the inside of the bend. The opposite will happen when the tubing is under compressive loads. The following figure shows all three effects presented in one well in a single load case.

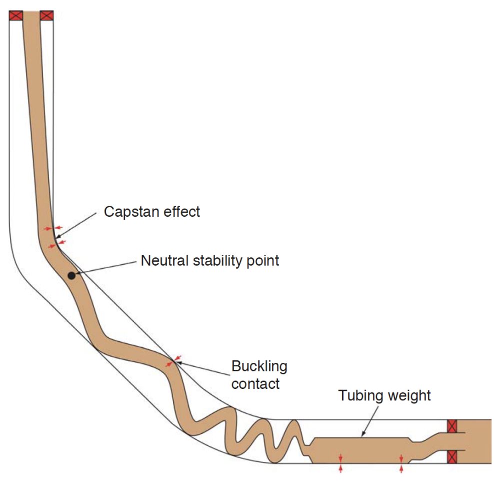

Figure 2.8: Tubing-to-casing contact forces presented in a deviated well, Bellarby (2009a)

2.1.4 Different load effects on tubing

There are different load cases that expose the tubing in several ways such as thermal effect, ballooning, buoyancy, pressure, density, and hanging weight. The thermal effect has already been discussed in chapter 1, while buckling effect will be discussed in chapter 3. For all load effects explained, Lubinski's sign conventions are used, Lubinski (1962a). Compression force will be denoted as positive, tensile force as negative, shorten in length as negative, and elongate in length as positive.

Ballooning effect

The tubing is exposed to several types of pressures. It will be subjected to both radial and axial strain. These forces are connected through Poisson's ratio, 2.11:

$$\mu = -\frac{\text{Radial strain}}{\text{Axial strain}} \tag{2.11}$$

Radial stress can affect the tubing and the result is called ballooning. Ballooning is radial contraction or swelling which occurs when average pressure changes. If the tubing string cannot move, stress will be created in the tubing body.

Ballooning

Ballooning occurs when internal pressure is higher than external pressure ($\Delta \mathrm{p_i} > \Delta \mathrm{p_o}$). This will create a tension force on the packer. Figure **2.9** below shows a simplified sketch of how the ballooning effect forms the tubing like a balloon and the pressure change inside the tubing and annulus.

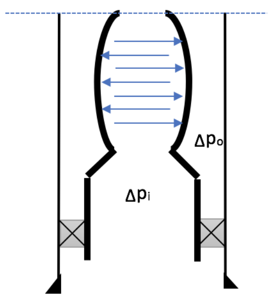

Figure 2.9: Ballooning $\rightarrow \Delta \mathrm{p_i} > \Delta \mathrm{p_o}$

Reverse ballooning

Reverse ballooning occurs when external pressure is higher than internal pressure($\Delta \mathrm{p_o} > \Delta \mathrm{p_i}$). This will create a compressive force on the packer. Figure **2.10** shows how reverse ballooning will affect the tubing and the location of the pressure changes.

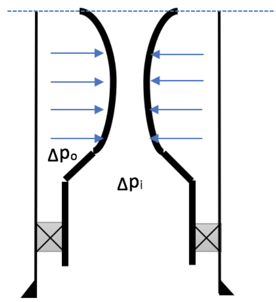

Figure 2.10: Reverse ballooning $\rightarrow \Delta p_o > \Delta p_i$

The resulting force due to ballooning or reverse ballooning can be derived as:

$$F_{\text{ballooning}} = -2\mu \cdot (A_i \Delta p_i - A_o \Delta p_o) \tag{2.12}$$

where,
$F_{\text{ballooning}}$ = axial force from ballooning/ reverse ballooning effect
Δp_i = change in average annulus pressure
Δp_o = change in average tubing pressure
μ = poisson's ratio

To compute the change in length due to ballooning effect, Hooke's law needs to be defined

$$\sigma = \frac{F}{A} \tag{2.13}$$

By combining equation (2.12) and (2.13), the length change due to ballooning or reverse ballooning can be derived:

$$\Delta L_{\text{ballooning}} = -\frac{2\mu}{E(A_o - A_i)}(A_i \Delta p_i - A_o \Delta p_o) \tag{2.14}$$

where,
$\Delta L_{\text{ballooning}}$ = length change due to ballooning effect

Piston effect

Archimedes' principle and buoyancy force

The principle of Archimedes is "when a body is submerged into a fluid, the buoyancy force equals the weight of the displaced fluid", Aandoy (2006). Buoyancy is a surface force acting upwards, which is the opposite direction of the gravitational force."For this reason, it is only pressure acting on the projected vertical area that contributes to buoyancy", Aandoy (2011). The calculation for buoyancy exerted in the body is given as:

$$\mathrm{F_b} = \oint_A \sigma \mathrm{dA} \tag{2.15}$$

(2.19) shows that the force can be determined by integrating the stress tensor over the surface of the body which is in contact with the fluid. Using assumptions and deviations the buoyancy force can then be expressed as:

$$\rho_{\mathrm{fluid}} \mathrm{hA} = \rho_{\mathrm{fluid}} \mathrm{V} \tag{2.16}$$

"The submerged weight of a wellbore tubular is obtained by multiplying the weight in air by a buoyancy factor, β", Aandoy (2011):

$$\beta = \frac{\text{Suspended weight in mud}}{\text{Weight in air}} = 1 - \frac{\rho_{\mathrm{mud}}}{\rho_{\mathrm{pipe}}} \tag{2.17}$$

"Temperature effect on the fluid density is often neglected because it is not as pronounced as pressure effect. However, for HPHT wells, where the temperature gradient is high, it is important to consider the effect of pressure and temperature on fluid density".
For different fluids densities, the buoyancy factor is:

$$\beta = 1 - \frac{\rho_{\mathrm{o}} \mathrm{r_o^2} - \rho_{\mathrm{i}} \mathrm{r_i^2}}{\rho_{\mathrm{pipe}} \cdot (\mathrm{r_o^2} - \mathrm{r_i^2})} \tag{2.18}$$

The general expression for the total buoyancy for a composite string consisting of n elements is then:

$$\beta = 1 - \frac{\sum_{k=1}^{n} \mathrm{D_k} (\rho_{\mathrm{o}} \mathrm{r_{o}}_{\mathrm{k}}^2 - \rho_{\mathrm{i}} \mathrm{r_{i}}_{\mathrm{k}}^2)}{\rho_{\mathrm{pipe}} \sum_{k=1}^{n} \mathrm{D_k} (\mathrm{r_{o}}_{\mathrm{k}}^2 - \mathrm{r_{i}}_{\mathrm{k}}^2)} \tag{2.19}$$

By using equation (2.19) the buoyancy factor can be computed starting from the bottom of the string. At any given depth, the axial weight is equal to the pipe weight below multiplied by the buoyancy factor at that depth, Aandoy (2011). For determining buoyancy the industry uses either Archimedes' principle or the piston force method.

Piston force method

The piston force is obtained by setting up a force balance. At each size transition, a force is obtained equal to the pressure multiplied by the exposed area. This is a one-dimensional approach. If the stability force is subtracted this method yields the same result as the Archimedes' principle, Aandoy (2006).

Piston forces “are loads caused directly by pressure on exposed cross sections of pipe”, Bellarby (2009a). When having PBR, the pressure inside the PBR will act on the difference between the seal bore area and the internal area of the tubing. While external pressure will act on the difference between the seal bore area and the outside area of the tubing.
Two different configurations have been showed below:

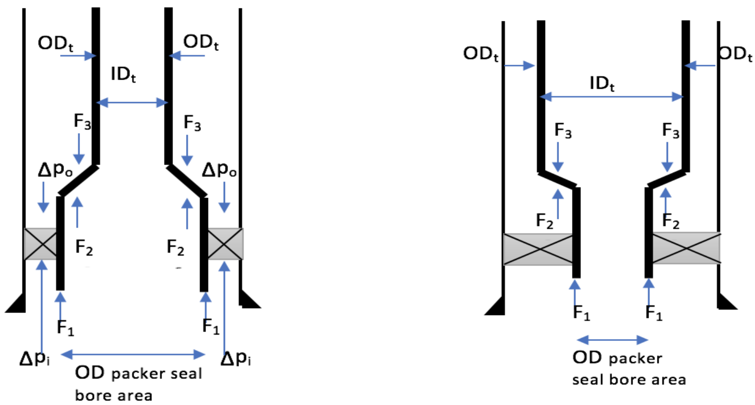

Figure 2.11: Configuration A shows when tubing ID $<$ packer OD and configuration B shows when tubing ID $>$ packer OD

Total force change is defined to be:

$$\Delta F_{piston} = (A_p - A_i) \cdot \Delta p_i - (A_p - A_o) \cdot \Delta p_o \tag{2.20}$$

where,
ΔF_{piston} = change in force
A_p = packer seal bore area = $\frac{\pi}{4} \cdot (OD_{pac})^2$
A_i = tubing area = $\frac{\pi}{4} \cdot (ID_t)^2$
Δp_i = change in tubing pressure at packer
A_o = tubing area = $\frac{\pi}{4} \cdot (OD_t)^2$
Δp_o = change in annulus pressure at packer

Total length change derived as:

$$\Delta L_{piston} = -\frac{L \cdot \Delta F_{piston}}{E \cdot A_s} \tag{2.21}$$

Chapter 3

Theory - Part II

3.1 Design strength of tubing

Tubulars in the well must be designed properly to cover all the anticipated load cases during the wells lifetime. This requires considerations like strength, load, performance, corrosion, grade, weight and other factors like economic aspect. The most essential properties of the casing and tubing are burst, collapse, and tensile strength. When designing a tubular, these properties need to be considered. In reality, pipes in the wellbore are subjected to combined loads. These can be evaluated by triaxial capacity diagrams which will be described in the sections below.

3.1.1 Selection of tubing grade

All variables that are used to define a tubing is necessary to understand. These variables are typically nominal OD, metallurgy, size range (length range), weight, connection and grade, Bellarby (2009b). There are several types and grades of a tubing. The American Petroleum Institute (API) has several requirements for tubing design. “All tubing should meet API minimum requirements”, SPE (2015). All API tubings are designed based on outer diameter(OD)[inch], weight [lbs/ft], grade of steel and wall thickness, Equipment (2008/2009).

For outer diameter, all tubing strings are standardized on OD following the API specification. Hence a $4^{1/2}$” tubing has an OD of $4^{1/2}$”. “API defines tubing as having an OD from $1^{1/20}$inch to $4^{1/2}$inch”, Bellarby (2009b). All tubulars with an outer diameter greater than this is defined or categorized as casing. For tubulars, the length range, R, is defined as joints. Following the API specification, it is only allowed to have two length ranges, but one can allow three ranges if necessary and practicable for the particular well. “ The API casing standard allows three ranges namely: Range 1: 16 to 25 feet, Range 2: 25 to 34 feet, Range 3: 34 to 48 feet”, Bellarby (2009b).

For weight, it is common to name tubulars with weight per foot[lb/ft]. "Since API standardizes tubulars on OD, an increase in wall thickness decreases the inside diameter (ID) and therefore increases the weight", Bellarby (2009b). As a result, tubulars are specified in terms of OD and weight of pipe per linear foot.

Another relevant element is the nominal ID. This inner diameter is calculated from outer diameter and weight per foot. The nominal ID is the parameter which should be used for strength and flow calculations. In addition, drift ID is important for especially tubings which are going to produce or do completion. This yields a safe passage of equipment through the tubing. "The standard for API drift is 0,125" smaller than the nominal ID", Bellarby (2009b). Coupling OD is the maximum outer diameter of the tubing connection. This is used when estimating the clearance required to install the tubing string into the casing.

Grade expresses the strength of the tubing. The grade of the tubing will partly also define the metallurgy, although a more detailed definition is needed to provide the full information of the metal. Figure **3.1** shows an example of a typical fully defined tubing nomenclature.

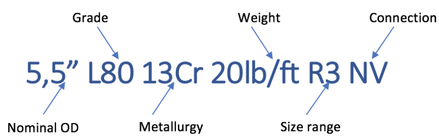

Figure 3.1: Example of a typical tubing nomenclature

API lists several types of grades for the tubing. The most common ones are H-40, J-55,N-80, L-80, C-75, where the letter specify name for various steels and number indicates the minimum yield strength of the steel in 1000 psi. These are described in detail in table **3.1**. "API defines the yield strength as the tensile stress required to produce a specific total elongation per unit length on a standard test specimen", SPE (2015).

Table 3.1: Typical tubing grades used in the industry with description of each type, SPE (2015), Equipment (2008/2009)

API tubing grade	Strength	Usage
H-40	Low strength steel	Not commonly used in tubing sizes because of the low the yield strength and the cost saving by using J-55 is minimal.
J-55	Low strength steel	Commonly used API grade for most wells when it meets the design criteria. A standard grade to chose for shallow and low-pressure wells on land.
N-80	High strength steel	A relatively old grade with essentially open chemical requirements.
L-80	High strength steel	A restricted yield-tubing grade
C-75	High strength steel	No longer an official API grade and generally not available or used.

There are other API high strength and non-API strength tubings which are available for sour service. High grade tubulars can lead to excessive cost, which may not be economical for a well design. On the other hand, selecting a tubular very close to the anticipated load might not be safe to operate the well. Thus, good knowledge of tubular grades are important.

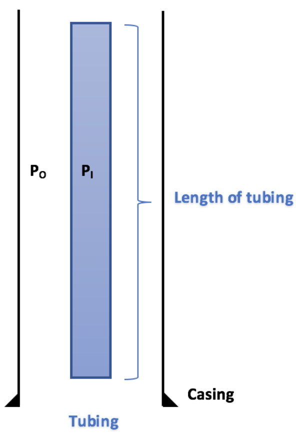

Figure 3.2: Sketch of a tubing with length of tubing, internal and external pressure

Tubing has several loads and mechanical properties. To design a reliable tubular, the actual strength of the pipe under different load conditions has to be found. The most essential mechanical properties of tubing are burst strength, collapse strength, and tensile strength. The figure above shows a simple sketch of a tubing were internal pressure is marked as P_I and outer pressure as P_o and the length of the tubing specified.

Burst load

Burst is a condition where internal pressure exceeds the pressure loading. It is defined as P_b, by the following formula:

$$P_b = P_I - P_O \tag{3.1}$$

where,
P_O = pressure in tubing-casing annulus/outside tubing
P_I = pressure inside tubing

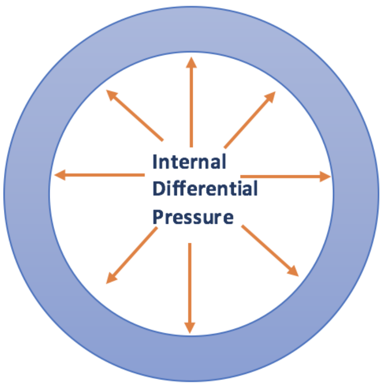

Figure 3.3: Figure shows how burst pressure will effect the tubular string

Burst may occur under well control operations, pumping operations, integrity tests, squeeze cementing etc, DrillingFormulas (2016a). The minimum burst rating pressure, also called internal yield pressure can be calculated by equation (3.5), also known as the Barlow equation, Economides (1998):

$$P_b = 0,875 \cdot \left[\frac{2 \cdot Y_p \cdot t}{D} \right] \tag{3.2}$$

where,
P_b = minimum burst pressure [psi]
Y_p = minimum yield strength [psi]
t = nominal wall thickness[inch]
D = nominal OD [inch]

The internal yield pressure is where tangential stress of the inner wall of the tubing reaches the minimum yield strength of the tubular pipe. "The factor of 0.875 appearing in the equation represents the allowable manufacturing tolerance of –12.5 % on wall thickness specified in API Bull", SPE (2016). "A burst failure will not occur until after the stress exceeds the ultimate tensile strength. Therefore, the use of yield strength criterion as a measure of burst strength is an inherently conservative assumption", Economides (1998).

The burst design factor is given as, Bellarby (2009b):

$$\mathrm{DF_{burst}} = \frac{\mathrm{P_b}}{\mathrm{P_i - P_o}} = \frac{\text{Minimum internal yield pressure}}{\text{Differential burst pressure}} \tag{3.3}$$

Collapse load

Collapse occurs when external pressure exceeds the internal pressure. It is defined as $\mathrm{P_c}$:

$$\mathrm{P_c = P_O - P_I} \tag{3.4}$$

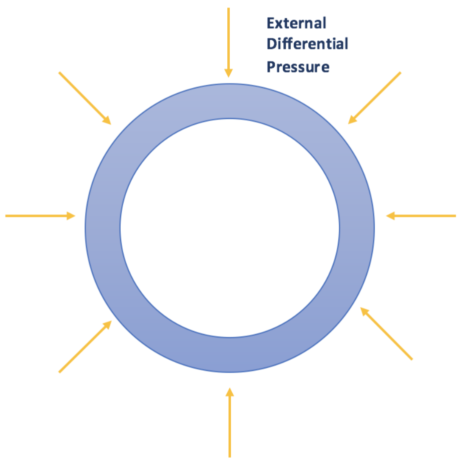

Figure 3.4: Figure shows how collapse pressure will effect the tubular string

Collapse develops in situations when pressure testing the annulus, during cementing operations, well evaluation etc, (DrillingFormulas, 2016b). "Collapse strength is primarily a function of the material's yield strength and its slenderness ratio, D/t". The equation for yield strength collapse can be estimated by the given formula, Economides (1998):

$$\mathrm{P_{Yp}} = 2\mathrm{Yp} \cdot \left[\frac{(\mathrm{D/t}) - 1}{(\mathrm{D/t})^2}\right] \tag{3.5}$$

where,
$\mathrm{P_{Yp}}$ = yield pressure [psi]

D/t = slenderness ratio
D = nominal OD [inch]

Collapse pressure equations are computed from experiments from test specimens and the full detail can be found in API Bulleting 5C3. Collapse design factor is given by, Bellarby (2009b):

$$DF_{collapse} = \frac{P_c}{P_o - P_i} = \frac{\text{Collapse pressure resistance}}{\text{Differential collapse pressure}} \tag{3.6}$$

Example - Analysing loads on tubing

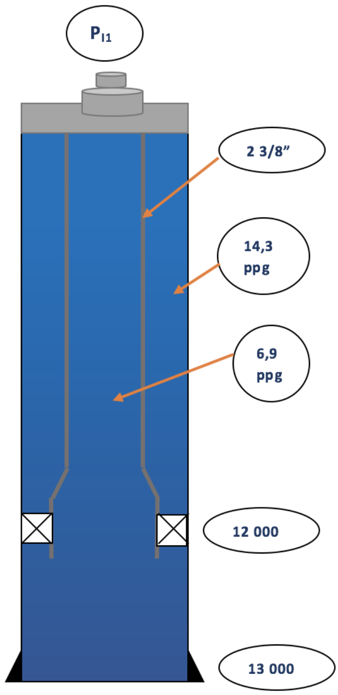

Figure 3.5: Illustration of an example well with defined variables

Burst load
The burst load is obtained from data for the given tubular string and well schematic shown in figure **3.5**. Burst load at the surface is calculated by using equation (3.1).

$$P_{b1} = P_{I1} - P_{O1} = 7000 - 100 = \underline{6900\text{psi}} \tag{3.7}$$

Further, burst load at the packer is calculated by taking into account the fluid in the tubing and annulus in addition to the depth:

$$\begin{aligned}\mathrm{P_{b2}} &= \mathrm{P_{I2}} - \mathrm{P_{O2}} = (\mathrm{P_{I1}} + \rho_\mathrm{I}\mathrm{L}) - (\mathrm{P_{O1}} + \rho_\mathrm{O}\mathrm{L}) \\ &= (7000 + 6,9 \cdot 0,052 \cdot 12000) - (100 + 14,3 \cdot 0,052 \cdot 12000) \\ &= \underline{2282\mathrm{psi}}\end{aligned}$$

Collapse load
Collapse load is calculated at the surface, by using equation (3.4)

$$\mathrm{P_{c1}} = \mathrm{P_{O1}} - \mathrm{P_{I1}} = 100 - 0 = \underline{100\mathrm{psi}} \tag{3.8}$$

At packer, the collapse load is calculated to be:

$$\begin{aligned}\mathrm{P_{b2}} &= \mathrm{P_{O2}} - \mathrm{P_{I2}} = (\mathrm{P_{O1}} + \rho_\mathrm{O}\mathrm{L}) - (\mathrm{P_{I1}} + \rho_\mathrm{I}\mathrm{L}) \\ &= (100 + 14,3 \cdot 0,052 \cdot 12000) - (0 + 0) \\ &= \underline{8923\mathrm{psi}}\end{aligned}$$

By multiplying the safety factor for both burst and collapse for the highest value found for each load, the maximum load the string can withstand is obtained. The calculation is shown below:

$$\text{Max Burst Load} = 6900\mathrm{psi} \cdot 1,125(\mathrm{SF}) = \underline{7763\mathrm{psi}} \tag{3.9}$$

$$\text{Max Collapse Load} = 8923\mathrm{psi} \cdot 1,125(\mathrm{SF}) = \underline{10038\mathrm{psi}} \tag{3.10}$$

The correct tubing design in tubing tables is found by selecting the lowest grade and weight of a tubing which has burst and collapse strengths that meet the respective loads. A possibility is to select a tubing that has lower collapse strength and by that prevent or control swabbing of the well. The last step is to check the tension load against the tensile strength of the selected tubing.

Tension load

Tension load is defined as, Equipment (2008/2009):

$$\mathrm{T} = \mathrm{w} \cdot \mathrm{L} + \mathrm{T_P} \tag{3.11}$$

where,
w = weight of tubing [lbs/ft]
L = length of tubing [ft]
T_P = tension required to set the packer or to pull the tubing out of the packer

From the given values of max burst load and max collapse load, a possibility is to select a $2^{3/8}$", J-55, 4,7lbs/ft tubing from a tubing table. This particular tubing have the given strengths:

Allowable collapse: 8230 psi
Allowable Burst: 8100 psi
Allowable Tension: 71 200 lbs

Calculating the maximum tension load at surface by using equation (3.11), gives:

$$\mathrm{T} = \mathrm{w} \cdot \mathrm{L} + \mathrm{T_P} = 4,7 \cdot 12000 + 10000 = 66400 \tag{3.12}$$

Then multiplying the safety factor, gives:

$$\text{Maximum tension load} = 66400 \cdot 1,3(\mathrm{SF}) = 86320\mathrm{lbs} > \text{Allowable tension} \tag{3.13}$$

From the equation above, it can be observed that the selected tubing will fail and therefore a stronger tubing must be selected to fit the requirements. The new tubing could be with the same weight but higher grade, or a tubing with the same grade but heavier weight. If one go by choosing the same grade but heavier weight, it is necessary to recalculate the tension load for the heavier tubing. $2^{3/8}$", N-80, 4,7lbs/ft tubing can for instance, be used in choosing the first alternative. This gives a maximum tension load of T =104300 lbs which is applicable for the given well design.

3.1.2 Combined loads - Triaxial load capacity diagram

The previous pipe strength equations are based on a uniaxial stress state. This is a state where only one of the three principal stresses is nonzero. However, in reality pipe in the well will always be subjected to combined loads in different conditions, Economides (1998).

"The fundamental basis of casing design is that if stresses in the pipe wall exceed the yield strength of the material, a failure condition exists. Hence, the yield strength is a measure of the maximum allowable stress". Triaxial stress is a combination of three stresses, axial stress (σ_a), radial stress (σ_r) and tangential stress (σ_θ). To evaluate pipe strength under combined loading conditions, the most used is the von Mises criterion. This is a yielding criterion, that says "[...]if the triaxial stress exceeds the yield strength, a yield failure is indicated", Economides (1998). It is as follows:

$$\sigma_\mathrm{VME} = \frac{1}{\sqrt{2}}[(\sigma_\mathrm{z} - \sigma_\theta)^2 + (\sigma_\theta - \sigma_\mathrm{r})^2 + (\sigma_\mathrm{r} - \sigma_\mathrm{z})^2]^{1/2} \geq \mathrm{Y_p} \tag{3.14}$$

where,
σ_VME= triaxial stress
σ_z= axial stress
σ_θ= tangential(hoop) stress
σ_r= radial stress
$\mathrm{Y_p}$= minimum yield stress

Axial, radial and tangential stress components can be illustrated in a pipe/cylinder like in figure **3.6**.

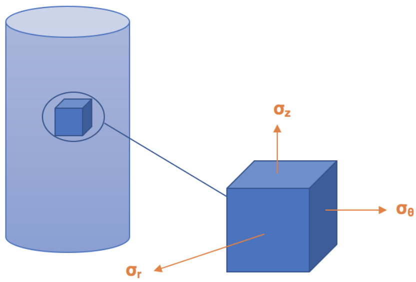

Figure 3.6: Illustration shows how axial, radial and tangential stress acts on a tubular string

"The calculated axial stress, σ_z, at any point along the cross-sectional area should include the effects of selfweight, buoyancy, pressure loads, bending, shock loads, frictional drag, point loads, temperature loads, and buckling loads", Economides (1998). The radial and the tangential stresses are based on Lamé equations for thick wall cylinders and are respectively as follows:

$$\sigma_r = \frac{r_i^2 - r_i^2 r_o^2/r^2}{r_o^2 - r_i^2} p_i - \frac{r_o^2 - r_i^2 r_o^2/r^2}{r_o^2 - r_i^2} p_o \tag{3.15}$$

$$\sigma_\theta = \frac{r_i^2 + r_i^2 r_o^2/r^2}{r_o^2 - r_i^2} p_i - \frac{r_o^2 + r_i^2 r_o^2/r^2}{r_o^2 - r_i^2} p_o \tag{3.16}$$

where,
r_i = inner wall radius
r_o = outer wall radius
r = radius
p_i = internal pressure
p_o = external pressure

It has been developed a method that represents triaxial load capacity of a pipe in a 2D graph. "The triaxial load capacity diagram is a representation of VME triaxial stress intensity in relation to axial force and either internal or external pressure", Bellarby (2009b). The diagram shows the burst region where external pressure equals zero psi as the top half (plane). The lower half (plane) represents the collapse region where internal pressure is zero psi. Service loads/combined loads which are to be tested, can be plotted in a triaxial load capacity diagram. In addition, is specified API load capacity design factor for burst pressure, collapse pressure and axial tension graphically plotted along with the diagram. It is then possible to make a direct comparison between the anticipated service loads and the API load capacity and the VME stress intensity design factor. An example of a typical triaxial load capacity diagram is shown in figure **3.7**.

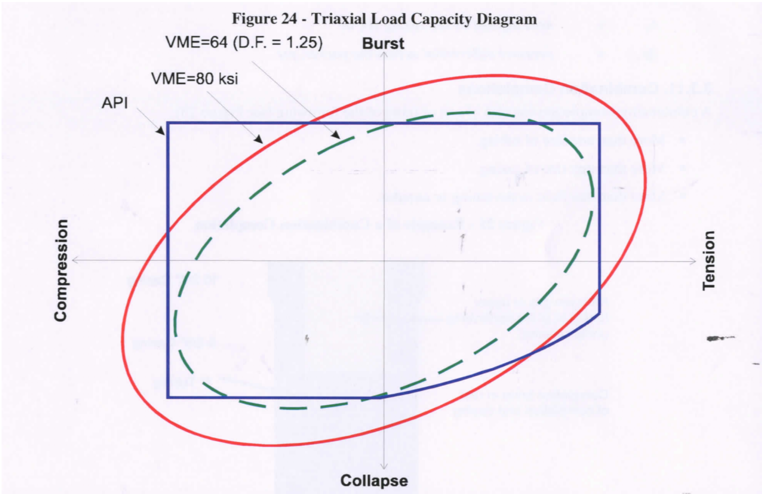

Figure 3.7: Figure showing a triaxial load capacity diagram, Bellarby (2009b)

In the figure, the API operation window marked in blue is the area enclosed to the API tension and pressure capacity of the particular pipe, adjusted by suitable design factors. “The biaxial effect of tension on collapse resistance is included”, Bellarby (2009b). The VME stress curve illustrated in both red and dotted green, defines the stress level in the pipe represented in terms of internal pressure, external pressure and axial force. By plotting a service load, the line will show the variation in the stress intensity in the tubing string over the length of the string. There are four quadrants presented in the figure which represent different combine loads, and have different effects on tubing design.

1. quadrant: Tension+Burst

The tubing will be subjected to a combined load of burst and tension in the upper right quadrant seen on the design envelope **3.7**. “In this region, reliance on the uniaxial criteria alone can result in a design that is more conservative than necessary”, Economides (1998). For loads with high burst pressure and moderate tension, a burst failure will not occur until after the API burst pressure has been exceeded. Burst failure may take place at a differential pressure less than the API value when the tension reaches the axial limit. “For high tension and moderate burst loads, pipe body yield will not occur until a tension greater than the uniaxial rating is reached”, Economides (1998). It is achievable to reduce cost without effecting wellbore integrity. This can be achieved by taking advantage of increased burst load in the presence of tension. It is also possible to allow loads to be within the uniaxial and triaxial tension limit ratings. However, these decisions should be taken with good care.

2. quadrant: Compression+Burst

The second quadrant in the figure represents the area where the tubing is exposed to both burst and compression. A triaxial analysis is critical in this region as the "reliance on unaxial criteria alone will not predict several possible failures", Economides (1998). Burst failure can occur at a differential pressure less than the API burst pressure when the tubing is exposed to high burst load and moderate compression. Helical buckling can lead to plastic deformation when there is high compression and moderate burst load. These combined load cases appear when there is high internal pressure caused by increased casing temperature, as a result of production. High internal pressure can also be a result of situations like tubing leak or annular pressure build up."The increased internal pressure also result on increased buckling", Economides (1998).

3. quadrant: Compression+Collapse

The tubing is subjected to a combination of compression and collapse load in the lower left quadrant. Moderate collapse and high compression loads can lead to permanent corkscrewing resulted from helical buckling. In these cases, it is essential to use triaxial criterion. The combination loads in this quadrant typically occurs in wells where there is a large temperature increase, caused by production. "The combination of a collapse load that causes reverse ballooning and temperature increase both increase compression in the uncemented portion of the string", Economides (1998).

4. quadrant: Tension+Collapse

For the lower right quadrant, "most design engineers use a minimum wall for burst calculations and nominal dimensions for collapse and axial calculations.", Economides (1998).

All well designs are recommended to use a triaxial analysis, as this has benefits like cost-saving aspects and gives better mechanical integrity. In burst design, by taking advantage of the high burst resistance in tension, money can be saved. For HPHT wells, large temperature effects on the axial load profile is included for combined loads of burst and compression. Buckling severity is evaluated by using the triaxial analysis. This is by knowing that "permanent corkscrewing occurs when the triaxial stress exceeds the yield strength of the material". Apart from all these elements, it has been "acknowledged that the von Mises criterion is the most accurate method of representing elastic yield behavior, use of this criterion in tubular design should be accompanied by a few precautions", SPE (2016).

3.1.3 Packer envelope

The figure below shows a typical illustration of a packer envelope. "The rating envelope is a graphical representation of the safe operating limits of the packer in combination with both differential pressure and axial loads", Fothergill (2002). Therefore packers are not only designed and used to withstand differential pressure for different downhole temperatures, but also needs to be able to keep safe pressure integrity when subjected to various compression and tensile loads. These loads are created by temperature and hydraulic effects on the tubing string. The packer envelope can also be referred to as the performance envelope.

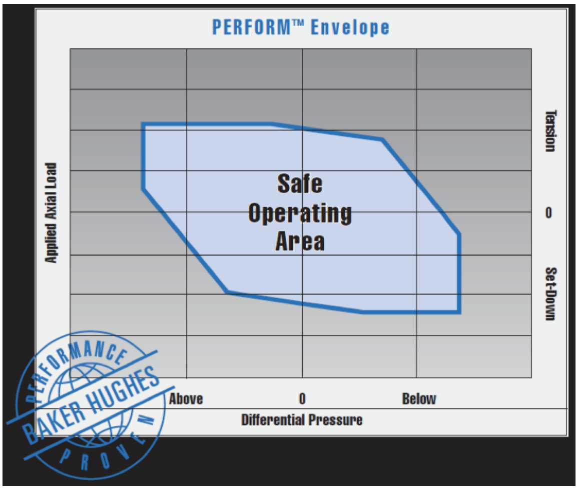

Figure 3.8: Example of a packer envelope

The packer envelope is a graph represented by two axis as seen in fig **3.8**. On the x-axis, the negative values represent tension, while the positive x-values represent values for compression. On the y-axis, the values equal differential pressure on the packer. The differential pressure from above the packer is shown as negative and below packer as positive, Fothergill (2002).

The strong blue line is shaped by boundary lines, which is created by the packer tested in all combined load conditions. The values are plotted on the graph and connected together by the boundary lines, which will create a ”box shape”. In these conditions, the packer is tested on its maximum packer ratings. Therefore will any loads of pressure and axial loads which comes inside the box be considered as safe and inside the tested limits for the particular packer.

In all cases, the packer envelope assumes that the casing is supported by cement. As discussed in the earlier sections, it is, therefore, important to assure that it has been done a good cement job, as well as that the TOC is above the production packer at the setting depth. The Casing will flex where it is unsupported, which results in a larger effective casing ID, NORSOK (2013). Referring to figure **1.3** showing the safe barrier envelopes.

If the casing is not cemented, or supported by cement the result will be that the forces which are acting on the production packer to act radially towards the casing. This will create a burst load on the casing and this will result in the casing inner diameter to expand radially. This is the same issue which occurs when ballooning occurs. When casing expands radially, the production packer has to do the same. The rubber and slips element will extend and move from its optimal positions, which leads to a reduced packer envelope.

The completion can be subjected to many loads, like production, injection, etc. It is essential to do calculations on tubing-movement to determine tubing-to-packer loads and differential pressures, as this will give an effective usage of the rating envelope. The load points will be plotted in the performance envelope to see if they fall within the safe zone of the packer design. If this is not the case, another packer must be considered, or the operations should be tailed to suit the operating limits of the packer.

3.1.4 Buckling

The tubing will hang straight in a vertical well or lay on the low side of the hole in deviated wells after it is installed. Thermal or pressure loads may produce compressive loads, and these loads can make initial conditions unstable if they are too high. A tubing is installed in within an open hole or a casing and can deform into another stable configuration called helical or sinusoidal shape. Generally is the helical shape seen in a vertical well and sinusoidal shape seen in a deviated wellbore. Buckling is per definition referred to the new equilibrium configuration which happens after the deformation is fell in place. It is essential to do an accurate analysis of buckling for several reasons, Economides (1998) as:

1. Buckling causes tubing movement
2. Buckling generates bending stresses which are not present in the original configuration.
3. Tubing buckling relieves compressive axial loads when the packer is fixed.

Buckling is a critical scenario to consider when looking at tubing stress analysis. Forces in the well can give changes in temperature and pressure during production on a tubing, which may cause compression and lead to buckling post installation. Thus, it is necessary to calculate buckling length changes and packer forces to evaluate where the neutral stability point is located on the tubing. When a tubing is buckling, the effective inner area of the pipe is reduced, which can be a problem for tool passage. A tubing should not deform, by reason of that tubing have a crucial part in a well design. A deformation can lead to reduced integrity of the well and further damage the environment around.

There are several reasons to why buckling is an important case when doing tubing stress analysis, which are, Bellarby (2009a):

1. Potential high bending stresses and therefore low axial (and triaxial) safety factors as well as bending loads on connections
2. Large tubing-to-casing contact forces which, in the presence of drag, can restrict axial loads transferring along the tubing.
3. Torque on connections that, in extreme cases, can unscrew them.
4. Shortening of the tubing when buckled – sometimes helpful, usually not.

5. Resulting doglegs that can limit through tubing access.

Buckling in a well is associated with the tubing where compression forces have to be presented to appear. Factors like internal and external pressure are influential, as these can cause complications. Figure **3.9** shows a small section of a tubing and how the presence of internal pressure gives a greater sideways force. The outside bend of the tubing has a greater area and results in a greater sideways force from internal pressure.

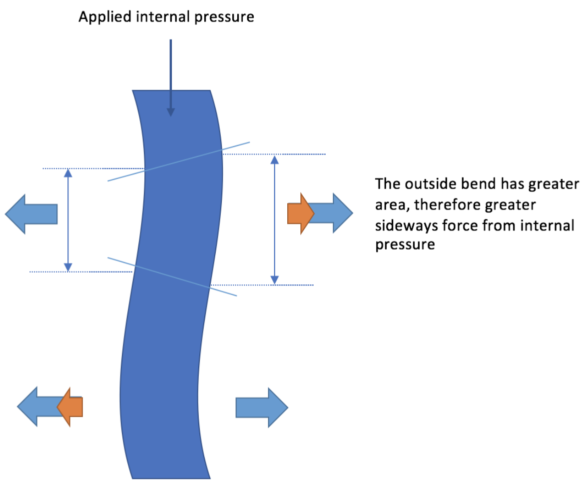

Figure 3.9: Buckling in a tubing caused by applied internal pressure

In the figure, the internal pressure inside the bend is acting on both sides of the tubing. The area of the bend outside is larger than the inside. "The sideways forces resulting from this pressure will tend to exacerbate the initial bend", Bellarby (2009a). In other words, the internal pressure is trying to shift the tubing to the right. While inside of the bend, the internal pressure is trying to shift the tubing to the left. Consequently, compression and internal pressure promote buckling, while external pressure and tension reduce the likelihood of buckling. It is noticeable that the right-hand force is greater than the left-hand force by reason of that the areas on the right are larger than those on the left.

The term effective tension (effective buckling force), F_{eff}, define the formula where compression and thermal pressure (p_i) promote buckling, while external pressure (p_o) and tension reducing the possibility of buckling:

$$F_{eff} = F_{total} + (p_o A_o - p_i A_i) \tag{3.17}$$

F_{total} is the total axial load where bending is not included. The effective buckling force is often referred to as the excess axial force. If F_{eff} is negative, the tubing will behave as if it is in compression, which will promote helical buckling. It is essential to clearly understand that a tubing which is slightly perturbed will want to buckle. This can not be avoided. “If the tubing is free to move and only subjected to pressure/area forces, the effective buckling force at packer depth reduces to”, Bellarby (2009b). For a vertical well, “where F_{eff} is greater than a critical force, buckling will tend not to occur; where F_{eff} is less than this critical force, buckling will tend to occur”. Buckling can therefore take place where the entire tubing string is exposed to tension, if the internal pressure is high enough. For a deviated well, “because A_o and A_i are not equal, there will be no buckling in open-ended pipe run into the well, unless there is drag or the tubing touches the base of the well”, Bellarby (2009a).

Sinusoidal and Helical buckling

The neutral point in the tubing is defined as the point where the effective axial load is zero. This can be interpreted as the boundary where buckling can and cannot occur. Figure **3.10** shows the neutral point of a buckled tubing. The critical force can be defined for two types of buckling. One is called sinusoidal buckling and one is called helical buckling.

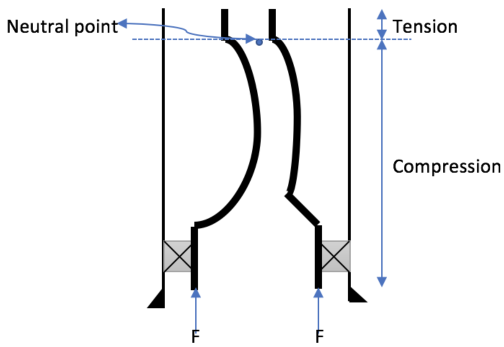

Figure 3.10: A buckled tubing, where netural point, tension and compression part is shown.

Sinusoidal buckling is often referred to as lateral buckling due to the S shape of the tubing, post buckling. The equation for the critical force for a vertical well, F_c, is given as:

$$F_c = 1.94(EIw^2)^{1/3} \tag{3.18}$$

where
F_c = critical force [lb]
w = buoyed tubing weight [lb/in]
I = moment of inertia [in4]

While in a deviated well, the critical buckling force is given as:

$$\mathrm{F_c} = \sqrt{\left(\frac{4\mathrm{Elwsin}\theta}{\mathrm{r_c}}\right)} \tag{3.19}$$

where,
θ = hole angle $\mathrm{r_c}$ = radial clearance [in]

For helical buckling is the critical force in a vertical well and a deviated well respectively given as:

$$\mathrm{F_c} = 4.05(\mathrm{Elw^2})^{1/3} \tag{3.20}$$

$$\mathrm{F_c} = 1.41 \sim 1.83\sqrt{\left(\frac{4\mathrm{Elwsin}\theta}{\mathrm{r_c}}\right)} \tag{3.21}$$

“The variation between 1.41 and 1.83 reflects the uncertainty about the point that sinusoidal buckling switches to helical buckling”, Bellarby (2009a). “The mathematical expression showing the relation between mode and axial force in constrained buckling phenomena depends on the type of buckling, i.e. helical and sinusoidal buckling”, Lubinski (1962a). The mathematical expressions for sinusoidal buckling and helical buckling are too complicated to be expressed in simple versions. However, the equations expressed above is the usual way to express both, describing the critical limit for both the buckling issues.

Problems like drill string failure, stick slip damage, mechanical damage on tubulars or bit and lockup can be caused by sinusoidal and/or helical buckling. This is a result of “excessive axial compression force on the drill string”, Lubinski (1962a). The industry has been more aware of bucking issues of pipe, especially as more high deviated wells and longer horizontal wells are being drilled. As a result, it is important to design the tubing properly to avoid buckling issues which can damage the well.

Chapter 4

Results

Several loads in the well are affected by pressure and temperature difference. In terms of pressure, it is the packer fluid outside the tubing and the formation fluid inside the tubing. These differences act on the tubing with radial, axial and tangential components. The effect which gives the most significant change for the tubing, is possibly the increase in temperature.

Steel and fluid in the annulus are heated up when production in the well starts. With an increase in temperature, both steel and fluid expands. These changes from initial condition, for initial temperature and pressure, are essential in well design and particularly tubing design in this thesis. For tubing design analysis the software WellCat™ is used, where the initial conditions are uploaded. The initial temperature is assumed to be the geothermal gradient and the tubing and annulus is assumed to contain packer fluid. The wellhead pressure is determined on if the initial well design is set onshore or offshore.

In the following section, two wells are introduced where one is constructed to be a vertical well, called ”X” and one horizontal/deviated well called ”Y”. Both wells have the same TVD, input and production data. The only difference is the wellpath. Both wells are modeled in WellCat™ to analyze load cases and resulting packer forces on each load case. Data is used from real example wells.

Design limit plot is created to visualize the integrity of the chosen tubing. Triaxial forces along the tubing are included for each load case in the design limit plot. API and von Mises criterion is included in the design limit plot as these are the industry standard. A presentation of resulting packer forces of each load case and a plot of each load case in a packer envelope is created to confirm the packer integrity. The final analysis presented is the tubing movement for one vertical well and deviated well and the comparison of each effect for these wells.

4.1 Vertical well ”X”

The vertical well constructed in the software WellCat is planned to be a vertical oil producer, with a total length of 8218 ftMD, or equivalently 8212 ftTVD. The upper completion consists of a 2 $^{7/8}$” monobore production tubing. Figure below shows the well schematic of well ”X”.

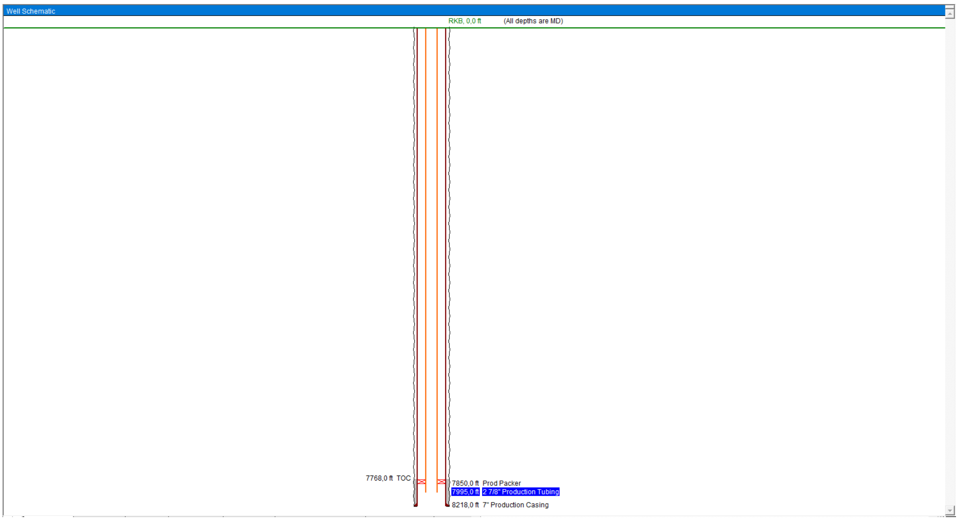

Figure 4.1: Well schematic showing the production packer, tubing and casing setting depth and TOC for well ”X”

The production packer is placed in a 7” casing. It is set at 7850 ftMD as seen in figure **4.1**, sealing off the annulus between the production tubing and the 7” production casing. The packer is set hydraulically at at an initial set pressure of 5080 psi and a plug depth of 7850 ftMD. TOC is set to be at a 7768 ftMD for the 7” production casing. This is about 50 m (164 ft) above the production packer, to keep a good well integrity, as production packer is one of the elements in the primary barrier envelope. Casing and tubing design and setting depths are shown in table **4.7**.

Table 4.1: Casing and tubing design summary for well ”X” from WellCat

Casing and Tubing Configuration

	Name	Type	OD (in)	MD (ft)			Hole Size (in)	Annulus Fluid
				Hanger	TOC	Base		
1	Production	Casing	7,000	0,0	7768,0	8218,0	8 1/2	Fresh Water
2	Production	Tubing	2 7/8	0,0		7995,0		30 deg API Oil
3								

Critical loads that the tubing may be exposed to during its lifetime are essential to evaluate. By simulating all these loads when planning a well, it can be possible to find out if a complete well design fit the requirements for the expected load cases. If one or several loads are identified outside a design limit plot or packer envelope, they have to be analyzed again. This may require changes in the tubing design.

4.1.1 Packer forces - Vertical well "X"

Several loads have been simulated to estimate the resultant packer forces; tubing-to packer force, latching force and packer-to casing force for well "X". The calculations are done in a comprehensive calculator in excel, made in the master project, Tharmapalan (2019).

Table **4.4** shows the most significant loads and the resultant forces on the packer in well "X", simulated in excel. To compute the resultant forces, it is necessary to have input data for the given well. Table **4.2** shows the axial loads and external pressures above and below the production packer for each load case. These values are gathered from the simulated well data in WellCat. Force is calculated in the usual form and to convert to kN, the equation is multiplied with 100:

$$F_{kN} = p \cdot \text{Area} \cdot 100 \tag{4.1}$$

Table 4.2: Packer data for well "X"

Load	[kN] Axial load Above	[kN] Axial load Below	[bar] Pressure Above	[bar] Pressure Below	[kN] Force Above	[kN] Force Below
Pressure test tubing	64,585	-63,41	218,9582	574,4724	0	67,1585305
Pressure test annulus/packer	-79,372	-24,597	550,541	242,4725	0	28,3461778
Early stage production	-101,789	-44,966	212,8281	413,4195	0	48,3306876
Steady stage production	-74,868	-70,209	211,4947	629,2447	0	73,5616704
Early stage injection	119,095	-44,571	220,2117	414,0586	0	48,4054014
Steady stage injection	120,76	-46,146	220,3917	427,2919	0	49,9524365
Shut-in short after production	-170,325	4,033	197,9113	1,3562	0	0,15854617
Shut-in long after production	52,59	-58,196	217,4876	530,0785	0	61,9686744
Start bullheading	54,815	-59,6	217,4869	542,0857	0	63,3723726
Free string weight	-25,535	-25,535	249,6693	249,6756	0	29,1882541

In figure **4.2** the axial force above and below the packer in the tubing is shown.

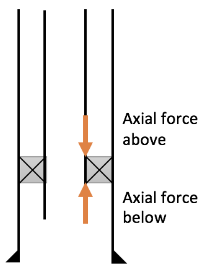

Figure 4.2: Sketch showing axial force above and below the packer

While figure **4.3** shows how the pressure acts both above and below the packer in the annulus.

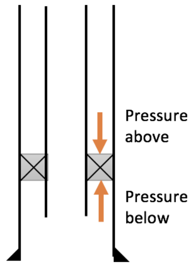

Figure 4.3: Sketch showing pressure above and below the packer

The following tables show the input values used based on the determined tubular design for well ”X”.

Table 4.3: Tables showing the simulation made for the tubular designing parameters

(a) Shows the selected tubular and sealbore diameter

	[in]	[m]	[m^2]
Tubing OD	2,875	0,073025	0,00418825
Tubing ID	2,441	0,0620014	0,00301921
Sealbore ID	2,875	0,073025	0,00418825
Casing ID	6,094	0,1547876	0,01881751

(b) Shows the computed value for area below, above and annulus

	[m^2]
Area below	0,00116905
Area above	0
Area annulus	0,01462926

Equations for area below, above and annulus are shown respectively:

$$\text{Area below} = \text{Sealbore ID} - \text{Tubing ID} \tag{4.2}$$

$$\text{Area above} = \text{Sealbore ID} - \text{Tubing OD} \tag{4.3}$$

$$\text{Area annulus} = \text{Casing ID} - \text{Tubing OD} \tag{4.4}$$

The estimated areas will automatically appear if tubular design data are chosen. Table **4.4** shows the resulting packer forces for each load case simulated. The free string weight is taken into account as it is useful when coordinates for each load case needs to be found. This is to plot these values into a packer envelope and confirm the packer integrity.

Table 4.4: Simulation done excel for resulting forces on packer for well ”X”

	[kN]	[kN]	[kN]
Load	**Tubing-to-packer force**	**Packer-to-casing force**	**Latching force**
Pressure test tubing	-127,995	-648,0859148	131,7435305
Pressure test annulus/packer	54,775	505,4563736	-51,02582222
Early stage production	56,823	-236,6273452	-53,45831241
Steady stage production	4,659	-606,4782757	-1,306329559
Early stage injection	-163,666	-447,2496418	167,5004014
Steady stage injection	-166,906	-469,5856519	170,7124365
Shut-in short after production	174,358	461,9035376	-170,1664538
Shut-in long after production	-110,786	-568,0833095	114,5586744
Start bullheading	-114,415	-589,2789768	118,1873726
Free string weight	0	-0,009216433	3,653254115

The table below shows the results simulated in WellCat^{TM}, which apparently gives the same values as table **4.4**:

Table 4.5: WellCat results for packer loads - well ”X”

Packer Loads - 2 7/8" Production Tubing - Prod Packer (Packer @ 7850,0 ft MD)

	Load	Tubing-to-Packer Force (kN)	Axial Load		Annulus Pressure		Temperature (°F)	Latching Force (kN)	Packer-to-Casing Force (kN)
			Above (kN)	Below (kN)	Above (bar)	Below (bar)			
1	Pressure test tubing	-127,994	64,585	-63,410	218,9582	574,4724	119,50	131,665	-648,085
2	Pressure test annulus/packer	54,776	-79,372	-24,597	550,5410	242,4725	119,50	-51,105	505,457
3	Early stage prodction	56,824	-101,789	-44,966	212,8281	413,4195	195,71	-53,454	-236,626
4	Steady stage production	4,660	-74,868	-70,209	211,4947	629,2447	209,37	-1,304	-606,477
5	Early stage injection	-163,666	119,095	-44,571	220,2117	414,0586	57,04	167,502	-447,249
6	Steady stage injection	-166,905	120,760	-46,146	220,3917	427,2919	56,54	170,713	-469,585
7	Shut-in short after production	174,358	-170,325	4,033	197,9113	1,3562	207,77	-170,167	461,904
8	Shut-in long after production	-110,786	52,590	-58,196	217,4876	530,0785	123,44	114,555	-568,083
9	Start bullheading	-114,414	54,815	-59,600	217,4869	542,0857	123,44	118,184	-589,278
10	Free string weight	N/A	-25,535	-25,535	249,6693	249,6756	119,50	3,653	N/A
11									
12	**Negative forces are in the upward direction.**								

4.1.2 Packer envelope - Verical well ”X”

It is possible to plot loads in an actual packer envelope from results found in the section above. A summary of simulated packer loads for well ”X” is shown in table **4.6**. Loads are calculated based on values in table **4.2** and equation (4.5) is used:

$$\text{Force} = \text{Axial Load Above} - \text{Free String Weight} \tag{4.5}$$

When plotting values into the packer envelope, the axial load above is the most important one. The reason for this is because one has no control over the axial load below the packer. The axial load above will be affected by the force above, which include buoyancy and TVD.

To calculate the differential pressure (Δp), equation (4.6) and values in table **4.2** are used.

$$\Delta \text{p} = \text{Pressure Above} - \text{Pressure Below} \tag{4.6}$$

Data for plotting packer envelope for well ”X” is given in table **4.6**. Loads and differential pressures are normally given in lbs and psi for a real packer envelope. Thus, the values in the table are converted into these units.

Table 4.6: Data for plotting an packer envelope - well ”X”

	[kN]	[bar]	[lbs]	[psi]
Load	**Load**	**ΔP**	**Force**	**ΔP**
Pressure test tubing	90,12	355,5142	20259,7817	5156,29754
Pressure test annulus/packer	-53,837	-308,0685	-12103,039	-4468,1558
Early stage production	-76,254	200,5914	-17142,581	2909,33229
Steady stage production	-49,333	417,75	-11090,499	6058,9515
Early stage injection	144,63	193,8469	32514,117	2811,51159
Steady stage injection	146,295	206,9002	32888,4239	3000,8337
Shut-in short after production	-144,79	-196,5551	-32550,086	-2850,7907
Shut-in long after production	78,125	312,5909	17563,1984	4533,74771
Start bullheading	80,35	324,5988	18063,3983	4707,90757

To illustrate how loads are plotted into a real packer envelope, a fictitious performance envelope is made:

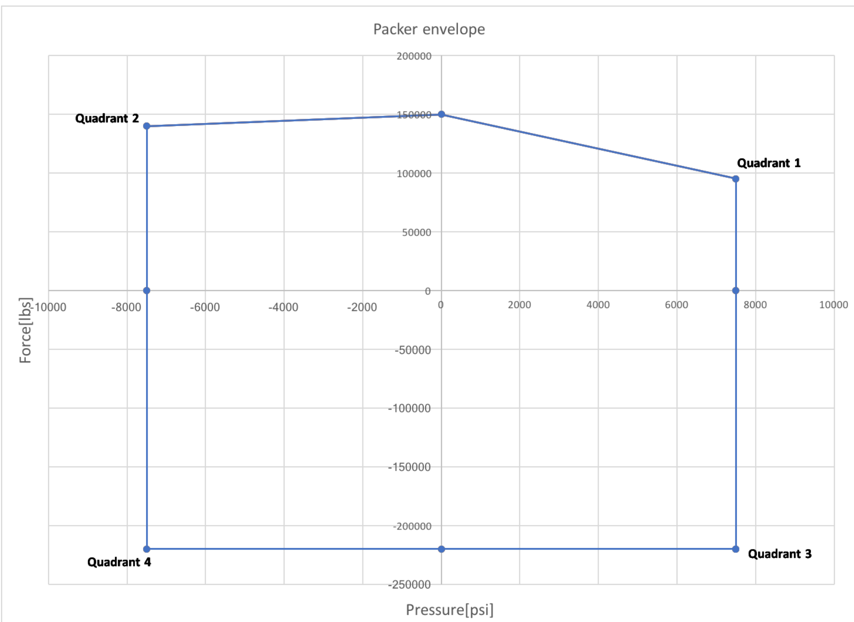

Figure 4.4: Shows a fictitious rating envelope

Quadrant 1 represent pressure from below with tension, while quadrant 2 pressure from above with tension. Quadrant 3 and 4 respectively show pressure from below and above with compression.

Each critical load case imposes a force on the production packer. The performance envelope for well ”X including all critical load cases are shown in figure **4.5**. The plot shows differential pressure and maximum tension or compression for all load cases. It can be observed that none of the load cases are outside the packer envelope.

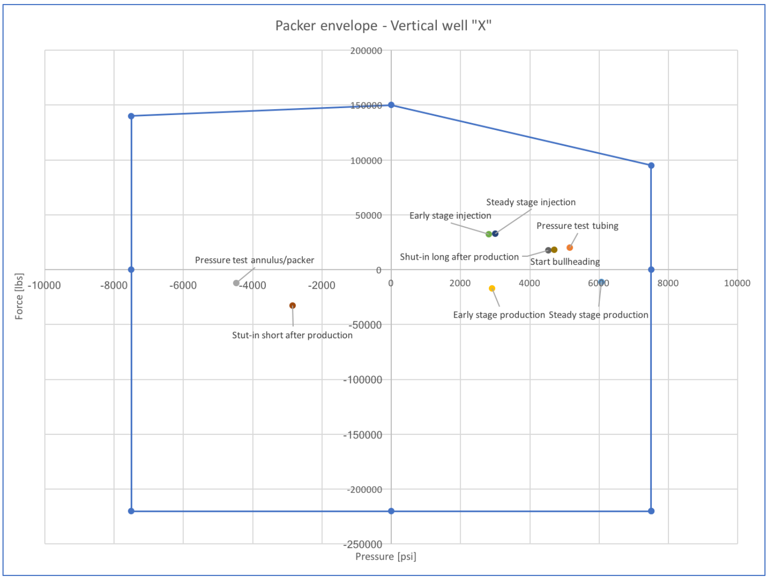

Figure 4.5: Packer envelope for well ”X”

4.1.3 Combined loads - Triaxial load capacity diagram - Vertical well ”X”

The triaxial loads for the chosen production tubing design, 2 7/8”, L-80 are presented in a design limit plot in WellCat. The limiting load case is ”Steady stage production” which appears right outside the von Mises criterion.

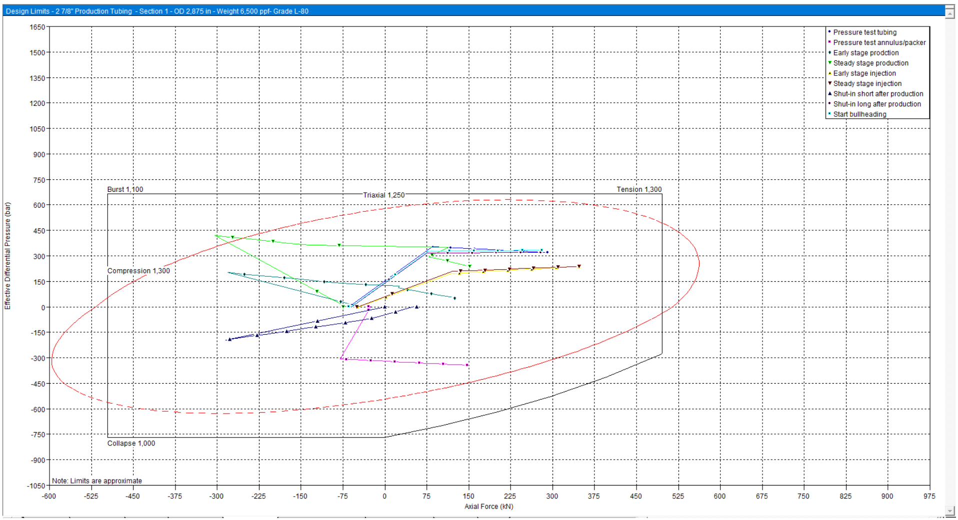

Figure 4.6: Design Limit Plot for the 2 7/8, L-80 Production Tubing - Well ”X”

4.2 Deviated well ”Y”

Well ”Y” is constructed in WellCat and planned to be a horizontal oil producer, with a total length of 30000 ftMD. The upper completion consists of a 2 $^{7/8}$” monobore production tubing, the same as for well ”X”. Figure **4.7** shows the well schematic of well ”Y”.

Figure 4.7: Well schematic with production packer, tubing and casing setting depth and TOC for well ”Y”

The production packer is placed in the 7” casing. It is set at 28500 ftMD to seal off the annulus between the production tubing and the 7” production casing. The packer is set hydraulically at an initial set pressure of 5080 psi and a plug depth of 28500 ftMD. TOC is set to be at 28000 ftMD for the 7” production casing. The following figure **4.8** shows the wellpath for well ”Y”.

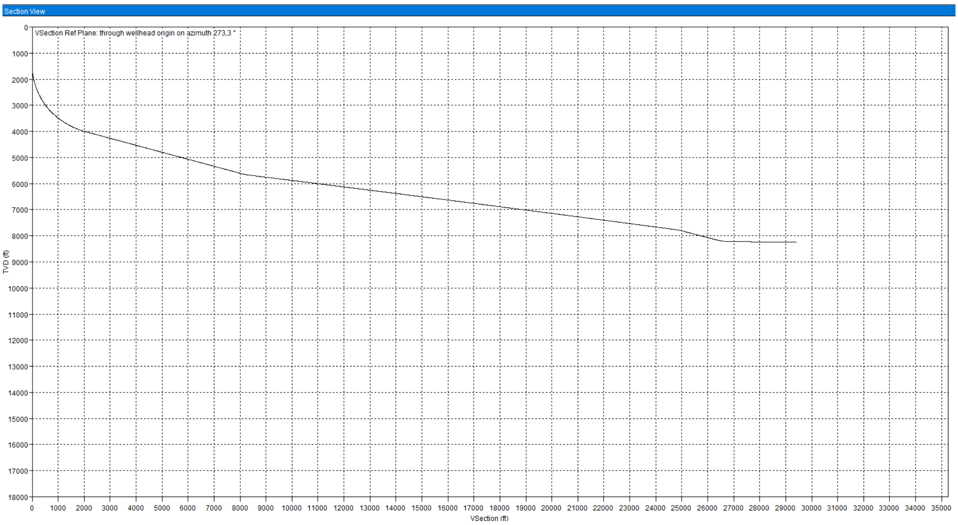

Figure 4.8: Section view of the deviated well ”Y”

The goal of constructing a deviated well is to be able to compare load cases, design limits, packer forces and packer envelope for a tubing upon a vertical well. This is to see if there are any changes required for the tubing design and find possible challenges and solutions. Casing and tubing design for the deviated well is summarised in the table below.

Table 4.7: Casing and tubing design summary for well ”Y” from WellCat

Casing and Tubing Configuration

	Name	Type	OD (in)	MD (m) Hanger	MD (m) TOC	MD (m) Base	Hole Size (in)	Annulus Fluid
1	Production	Casing	7,000	0,00	8534,40	9144,00	8 1/2	Fresh Wate
2	Production	Tubing	2 7/8	0,00		8839,20		30 deg API Oi
3								

4.2.1 Packer forces - Deviated well ”Y”

To find tubing-to packer force, latching force and packer-to casing force for well ”Y” identical simulations were performed. Table **4.8** shows the most critical loads for the tubing in well ”Y” with axial loads and pressure above and below the production packer.

Table 4.8: Packer data for well "Y"

	[kN]	[kN]	[bar]	[bar]	[kN]	[kN]
Load	**Axial load**	**Axial load**	**Pressure**	**Pressure**	**Force**	**Force**
	Above	**Below**	**Above**	**Below**	**Above**	**Below**
Pressure test tubing	78,574	-63,927	219,2225	574,692	0	67,1842028
Pressure test annulus/packer	-64,894	-25,114	550,8052	242,6921	0	28,3718501
Early stage production	70,368	-98,343	207,4612	855,8003	0	100,047088
Steady stage production	124,961	-132,306	207,171	1146,968	0	134,085964
Early stage injection	350,411	-22,905	218,6521	227,6862	0	26,6175896
Steady stage injection	356,504	-28,404	219,0355	273,9391	0	32,0247716
Shut-in short after production	34,126	-34,536	193,5869	323,7233	0	37,8447792
Shut-in long after production	172,38	-57,479	213,1729	519,9461	0	60,7841491
Start bullheading	174,559	-58,882	213,1729	531,9485	0	62,1872862
Free string weight	-26,051	-26,051	249,991	249,9926	0	29,2253129

The resultant forces acting on the packer is shown in table **4.9**. To find these, the same calculation method for well "X" is used. Thus, this will not be repeated and only the output values are shown.

Table 4.9: Simulation done excel for resulting forces on packer for well "Y"

	[kN]	[kN]	[kN]
Load	**Tubing-to-packer force**	**Packer-to-casing force**	**Latching force**
Pressure test tubing	-142,501	-662,526522	145,7582028
Pressure test annulus/packer	39,78	490,5266201	-36,52214994
Early stage production	-168,711	-1117,183032	170,4150876
Steady stage production	-257,267	-1632,120329	259,0469637
Early stage injection	-373,316	-386,5322185	377,0285896
Steady stage injection	-384,908	-465,2278959	388,5287716
Shut-in short after production	-68,662	-259,0419042	71,97077916
Shut-in long after production	-229,859	-678,6454457	233,1641491
Start bullheading	-233,441	-699,786067	236,7462862
Free string weight	0	-0,002340681	3,174312909

The table below shows the results simulated in WellCat:

Table 4.10: WellCat results for packer loads - well "Y"

Packer Loads - 2 7/8" Production Tubing - Prod Packer (Packer @ 28500,0 ft MD)

	Load	Tubing-to-Packer Force (kN)	Axial Load		Annulus Pressure		Temperature (°F)	Latching Force (kN)	Packer-to-Casing Force (kN)
			Above (kN)	Below (kN)	Above (bar)	Below (bar)			
1	Pressure test tubing	-142,500	78,574	-63,927	219,2225	574,6920	241,02	145,690	-662,526
2	Pressure test annulus/packer	39,780	-64,894	-25,114	550,8052	242,6921	241,02	-36,590	490,526
3	Early stage prodction	-168,710	70,368	-98,343	207,4612	855,8003	245,81	170,369	-1117,182
4	Steady stage production	-257,267	124,961	-132,306	207,1710	1146,9680	248,70	258,920	-1632,120
5	Early stage injection	-373,317	350,411	-22,905	218,6521	227,6862	86,26	377,041	-386,533
6	Steady stage injection	-384,908	356,504	-28,404	219,0355	273,9391	84,06	388,539	-465,227
7	Shut-in short after production	-68,662	34,126	-34,536	193,5869	323,7233	248,40	71,971	-259,042
8	Shut-in long after production	-229,858	172,380	-57,479	213,1729	519,9461	237,90	233,143	-678,644
9	Start bullheading	-233,440	174,559	-58,882	213,1729	531,9485	237,90	236,726	-699,785
10	Free string weight	N/A	-26,051	-26,051	249,9910	249,9926	241,02	3,174	N/A
11									
12	**Negative forces are in the upward direction.**								

4.2.2 Packer envelope - Deviated well ”Y”

The results found in the section above are used to plot loads in an actual envelope for well ”Y”. A summary of the packer loads and differential pressure determined in excel are shown in table **4.11**. Loads are calculated based on table **4.8**, further equation (4.5) is used. To compute the differential pressure(Δp), equation (4.6) and values in table **4.8** are used. The results from the excel simulation are shown in table **4.11**.

Table 4.11: Data for plotting an envelope - well ”Y”

	[kN]	[bar]	[lbs]	[psi]
Load	**Load**	**ΔP**	**Force**	**ΔP**
Pressure test tubing	104,625	355,4695	23520,6353	5155,64922
Pressure test annulus/packer	-38,843	-308,1131	-8732,2537	-4468,8027
Early stage production	96,419	648,3391	21675,8532	9403,36365
Steady stage production	151,012	939,797	33948,8476	13630,6031
Early stage injection	376,462	9,0341	84632,0232	131,028543
Steady stage injection	382,555	54,9036	86001,784	796,309395
Shut-in short after production	60,177	130,1364	13528,3276	1887,46891
Shut-in long after production	198,431	306,7732	44609,0628	4449,3691
Start bullheading	200,61	318,7756	45098,9215	4623,4492

Data from the table above are used to plot values into the performance envelope **4.4**. The performance envelope for well ”Y” is shown in figure **4.9**. It can be observed that two loads cases; ”Early stage production” and ”Steady stage production” appear outside the envelope.

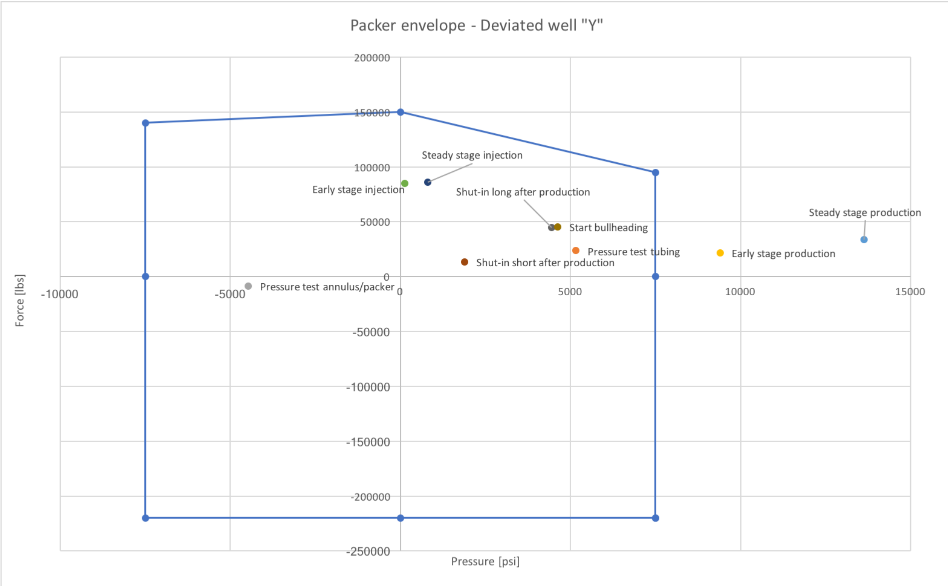

Figure 4.9: Packer envelope for well ”Y”

4.2.3 Combined loads - Triaxial load capacity diagram - Deviated well ”Y”

The triaxial loads for well ”Y” and the chosen production tubing are presented in a design limit plot **4.10**. The same tubing size and grade used for well ”X” is also used for well ”Y”. However, it can be observed that the limiting load cases for the deviated well are ”Steady stage production”, ”Early stage injection” and ”Steady stage injection” which appears outside the von Mises criterion and API design limits.

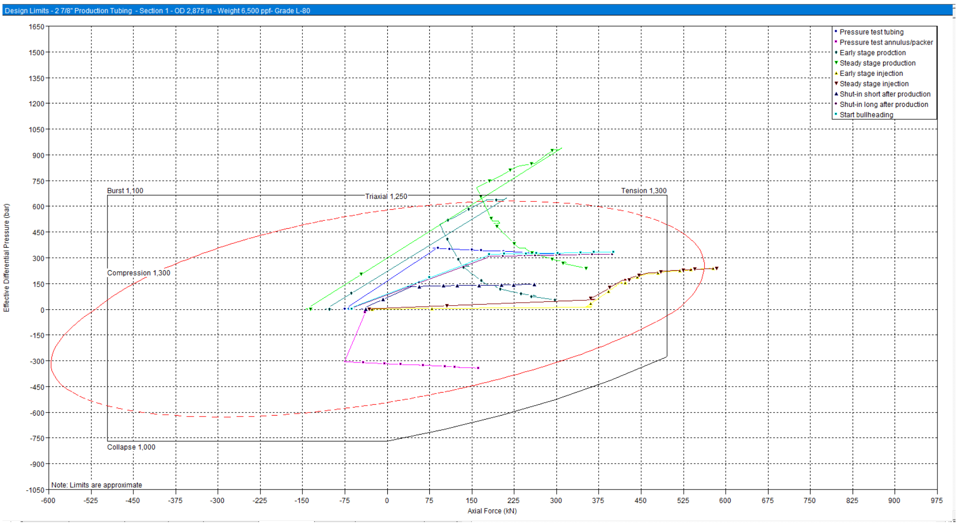

Figure 4.10: Design Limit Plot for the 2 7/8, L-80 Production Tubing - Well ”Y”

4.3 Tubing movement

In the following section, tubing movement results are presented. The simulated effects are thermal, ballooning, piston/hooke’s law and buckling. To see how output changes for different software tools, one vertical and deviated well is being used. The softwares use different equations to determine the results. The vertical well data is taken directly from Lubinski’s example in the paper “Helical Buckling of Tubing Sealed in Packers”, Lubinski (1962b). While the deviated well is the same well presented in chapter 4, called well ”Y”. Software tools which are used to compute the results are Matlab, WellCat and Excel. In Matlab, the simulated code is taken from Remmen (2018) and is made by a former master student at NTNU. While myself have simulated data in Excel and WellCat to compute the results for both wells.

4.3.1 Vertical well - Lubinski’s example

The vertical well presented in this section is used from Lubinski’s example. The well data, tubing, and casing design from the paper are used in Matlab, Excel and WellCat to get the most exact comparison of the results.

WellCat

The well schematic, casing and tubing design for the vertical well simulated in WellCat are shown in respectively figure **4.11** and table **4.12**.

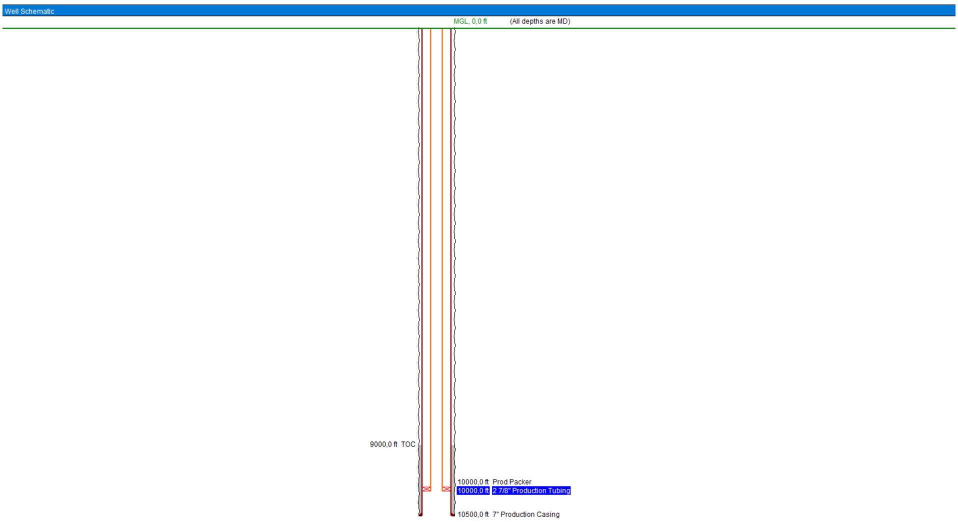

Figure 4.11: Well schematic of the vertical well

Table 4.12: Casing and tubing configuration for the vertical well modelled in WellCat as Lubinski's example

Casing and Tubing Configuration

	Name	Type	OD (in)	MD (ft)			Hole Size (in)	Annulus Fluid
				Hanger	TOC	Base		
1	Production	Casing	7,000	0,0	9000,0	10500,0	8 1/2	Fresh Water
2	Production	Tubing	2 7/8	0,0		10000,0		30 deg API Oil
3								

The movement table computed in WellCat is shown below. For vertical wells, WellCat uses Lubinski's equations, Lubinski (1962b). The table shows the tubing movement in length changes for the most critical effects for a tubing.

Table 4.13: Movement table for each effect and total change taken from WellCat

Length Change View - Inject Slurry - 2 7/8" Production Tubing

	MD (ft)		Hooke's Law (ft)	Buckling (ft)	Balloon (ft)	Thermal (ft)	Total (ft)
	Top	Base					
1	0,0	10000,0	-5,65	-3,84	-2,90	-1,38	-13,77

Where results converted from ft to inches are:

- Hook's law = Piston effect = -67 inch
- Buckling effect = -46 inch
- Ballooning effect = -34 inch
- Thermal effect = -16 inch

- Total length change = -165 inch

Matlab
The Matlab code runs through the same input values for each tubing movement for the vertical well and uses Lubinski's equations, Lubinski (1962b) as WellCat. In the code, dL1 represents the piston effect, dL2 the buckling effect, dL3 the ballooning effect, while dL4 shows the thermal effect. The total length change is expressed as dL. The results are shown in figure **4.12**.

```
dL1 =

  -67.8700


dL2 =

  -46.0954


dL3 =

  -34.7946


dL4 =

  -16.5600


dL =

 -165.3200

If the tubing is free to move, the total length change is -165.32 in
```

Figure 4.12: Matlab code output data for the vertical well

Excel
The excel sheet runs through the same equations, Lubinski (1962b), as the other two softwares for the vertical well. When needed input values are inserted in the sheet, the right tubing movement for each effect is found. Below, each effect is shown in detail. Tubular designing parameters, input values for the given well and initial condition and final condition is shown.

Thermal effect

Thermal effect		
Well data	Lubinski's example - vertical well	
Packer setting depth [ft]/[inch]		
	10000	120000
Thermal expansion coefficient		
	0,0000069	
Young's modulus		
	30000000	
Inner diamter tubing [inch]		
	2,441057367	
Outer diamter tubing [inch]		
	2,875	
Inner area tubing [inch^2]		
	4,68	
Outer area tubing [inch^2]		
	6,491806694	
Cross sectional area of tubing, As [inch^2]		
	1,811806694	
Average temperature change [F]		
At initial condition	155	
At finial condition	135	
Temperature change in total	-20	cooling
Length of tubing [ft]/[inch]	10000	120000
Initial condition	Lubinski's	
Surface temperature [F]	80	
Bottomhole temperature [F]	230	
Finial condition		
Surface temperature [F]	60	
Bottomhole temperature [F]	210	
FINAL RESULT		
Length change due to thermal effect	**Δltemp[inch]**	-16,56

Buckling effect

Buckling effect		
Well data	Lubinski's example - vertical well	
Packer setting depth [ft/inch]		
	10000	120000
Young's modulus		
	30000000	
Inner diamter tubing [inch]		
	2,441057367	
Outer diameter tubing [inch]		
	2,875	
Packer seal bore outer diamter [inch]		
	3,25	
Inner diamter production casing [inch]		
	6,095	
Inner area tubing [inch^2]		
	4,68	
Outer area tubing [inch^2]		
	6,491806694	
Packer seal bore area [inch^2]		
	8,295768101	
At final condition [psi]		
Outer pressure at packer	4794,44	
Inner pressure at packer	12800	
Fictitious force, Ff [lbs]		
	66412,26928	
Density of fluid in the tubing [lb/inch^3]		
	0,064935	
Density of fluid ion the annulus [lb/inch^3]		
	0,031588713	
Weight og tubing per feet [lb/ft]		
	6,5	
Weight per unit length of tubular in the prences of fluid, W [lb/inch]		
Weight per unit weight of steel, Ws	0,541666667	
Weight per unit weight of fluid insude tubing, Wi	0,3038958	
Weight per unit weight of fluid outside tubing, Wo	0,205067819	
W	0,640494648	
Location of neutral point, n [ft]		
	8640,752564	
Length of tubing [inch]		
	120000	
Radial clearance between tubing OD and casing ID, r [inch]		
	1,61	
Moment of inertia of tubing cross section, I [inch^2]		
	1,610739869	
Initial condition	Lubinski's	
[ppg]		
Fluid in annulus	7,297	
Fluid in tubing	7,297	
[psi]		
Tubing pressure	0	
Annulus pressure	0	
Final condition		
[ppg]		
Fluid in annulus	7,297	
Fluid in tubing	15	
[psi]		
Tubing pressure	5000	
Annulus pressure	1000	
FINAL RESULT		
Length change due to buckling	**ΔLbuckling [inch]**	-46,17386586

Ballooning effect

Ballooning effect		
Well data	Lubinski's example - vertical well	
Packer setting depth [ft]		
	10000	120000
Poisson's ratio		
	0,3	
Young's modulus		
	30000000	
Inner diameter tubing [inch]		
	2,441057367	
Outer diamter tubing [inch]		
	2,875	
Inner area tubing [inch^2]		
	4,68	
Outer area tubing [inch^2]		
	6,491806694	
At inital condition [psi]		
Outer pressure at packer	3794,48	
Inner pressure at packer	3794,48	
Average outer pressure of tubular	1897,26	
Average inner pressure of tubular	1897,26	
At final condition [psi]		
Outer pressure at packer	4794,44	
Inner pressure at packer	12800	
Average outer pressure of tubular	2897,22	
Average inner pressure of tubular	8900	
Average annulus pressure change, DeltaPo	999,96	
Average tubing pressure change, DeltaPi	7002,74	
Initial conditon	Lubinski's	
[ppg]		
Fluid in tubing	7,297	30 degree API
Fluid in annulus	7,297	
[psi]		
Tubing pressure	0,04	
Annulus pressure	0,04	
Final condition		
[ppg]		
Fluid in tubing	15	
Fluid in annulus	7,297	
[psi]		
Tubing pressure	5000	
Annulus pressure	1000	
FINAL RESULT		
Length change due to ballooning effect	**Δlballooning [inch]**	-34,81335124

Piston effect

Piston effect		
Well data	Lubinski's example - vertical well	
Packer setting depth [ft]/[inch]		
	10000	120000
Young's modulus		
	30000000	
Inner diamter tubing [inch]		
	2,441057367	
Outer diamter tubing [inch]		
	2,875	
Packer seal bore outer diamter [inch]		
	3,25	
Inner area tubing [inch^2]		
	4,68	
Outer area tubing [inch^2]		
	6,491806694	
Packer seal bore area [inch^2]		
	8,295768101	
Cross sectional area tubing [inch^2]		
	1,811806694	
At initial conditon [psi]		
Outer pressure at packer	3794,44	
Inner pressure at packer	3794,44	
At finial condition [psi]		
Outer pressure at packer	4794,44	
Inner pressure at packer	12800	
Change in annulus pressure at packer [psi]		
	1000	
Change in tubing pressure at packer [psi]		
	9005,56	
Inital condition	Lubinski's	
[ppg]		
Fluid in tubing	7,297	
Fluid in annulus	7,297	
[psi]		
Tubing pressure	0	
Annulus pressure	0	
Finial condition		
[ppg]		
Fluid in tubing	15	
Fluid in annulus	7,297	
[psi]		
Tubing pressure	5000	
Annulus pressure	1000	
FINAL RESULT		
Lenght change due to piston effect	**ΔLpiston [inch]**	-67,90582079
Force change due to piston effect	**ΔFpiston [lbs]**	30758,05517

A summary of the total length change is found to be:

Table 4.14: Summary of all tubing movement and the total length change

Tubing movement	**Lubinski's example - vertical well**
	[inch]
Thermal effect	-16,56
Ballooning effect	-34,81335124
Piston effect	-67,90582079
Buckling effect	-46,17386586
Total length change	**-165,4530379**

A table **4.15** is presented where all results from Excel, Matlab and WellCat are gathered for tubing movement of the vertical well:

Table 4.15: Tubing movement summary for the vertical well from WellCat, Matlab and Excel

Effect	**WellCat[inch]**	**Matlab[inch]**	**Excel[inch]**
Thermal	-16	-16,5600	-16,56
Ballooning	-34	-34,7946	-34,81
Buckling	-46	-46,0954	-46,17
Piston	-67	-67,8700	-67,91
Total length change	-165	-165,3200	-165,45

4.3.2 Deviated well ”Y”

The deviated well presented in this section is well ”Y”. Matlab and WellCat is used to simulate the results. The same well data, casing, and tubing configuration is used to get the most exact comparison of the results.

WellCat

For deviated wells, WellCat uses Lubinski's equations, Lubinski (1962b) for thermal, ballooning and piston effect (Hooke's law). While for buckling effect a combination of Lubinski's and Mitchell's, Mitchell (1999) equation are used. The resulting tubing movements are shown in the following table.

Movement Summary - Steady state production - 2 7/8" Production Tubing

	MD (ft)		Hook's Law (ft)	Buckling (ft)	Balloon (ft)	Thermal (ft)	Total (ft)	Buckled Length (ft)
	Top	Base						
1	0,1	29000,0	-20,26	-21,28	-9,87	12,40	-39,01*	29000,0
2								
3	* Total movement exceeds allowable movement							

Figure 4.13: Movement table for the deviated well taken from WellCat

Where the effects in inches are:

- Hook's law = Piston effect = -243,12 inch
- Buckling effect = -255,36 inch
- Ballooning effect = -118,44 inch
- Thermal effect = 148,8 inch
- Total length change = -468,12 inch

Matlab

The Matlab code in Remmen (2018) includes Aadnøy (2002), Mitchell (1999) and Lubinski (1962b) equations for buckling effect in deviated wells while the other effects are based on Lubinski and Aadnøy's equations. The results are presented in figure **4.14**.

```
dL1 =

 -327.2056


dL2 =

 -143.6378


dL3 =

 -149.4521


dL4 =

  184.2921


dL =

 -436.0034

If the tubing is free to move, the total length change is -436.0034 in
```

Figure 4.14: Matlab code output data for the vertical well

where,
dL1 = Piston effect
dL2 = Buckling effect
dL3 = Ballooning effect
dL4 = Thermal effect
dL = Total length change

The summary from both the softwares are shown in the table below:

Table 4.16: Tubing movement summary for the deviated well from WellCat and Matlab

Effect	**WellCat[inch]**	**Matlab[inch]**
Thermal	148,8	184,2921
Ballooning	-118,44	-149,4521
Buckling	-255,36	-143,6378
Piston	-243,12	-327,2056
Total length change	-468,12	-436,0034

Chapter 5

Discussion

5.1 Resulting packer forces

Forces acting on the packer depend both on type and setting method. These forces can either cause compression or tension one the packer. When designing a packer it is essential to qualifying a possible rating envelope. By looking at the resulting forces acting on the packer, it is possible to identify the distributed forces on the packer for each load case. There are different load cases modeled for each well as described in chapter 4. It is fundamental to analyze the right load case and to define them correctly. The comprehensive calculator used for estimating resulting packer forces matched the results in WellCat.

As discussed in the section about well integrity, the primary barrier envelope includes the production packer. Since the cement around the casing where the packer is located is included in this barrier, it is obvious to look at the height of the cement. The height has to be selected to give good support for the pressure applied at the casing shoe, including for the production packer. Pressure and temperature variation after cementing can cause movement in the casing and leakage of well fluids. In addition, these effects may result in poor cement bonding, which can create small pathways through the cement. Moreover, a worn casing may be a problem by not giving enough support to the production packer. It is therefore important to verify the cement job and casing used in the well.

In this thesis, resulting packer forces are developed for each well and a stepwise calculation has been given to a better understanding. The resulting forces for the vertical well and deviated well is respectively given as:

Table 5.1: Simulation done excel for resulting forces on packer for well "X"

	[kN]	[kN]	[kN]
Load	**Tubing-to-packer force**	**Packer-to-casing force**	**Latching force**
Pressure test tubing	-127,995	-648,0859148	131,7435305
Pressure test annulus/packer	54,775	505,4563736	-51,02582222
Early stage production	56,823	-236,6273452	-53,45831241
Steady stage production	4,659	-606,4782757	-1,306329559
Early stage injection	-163,666	-447,2496418	167,5004014
Steady stage injection	-166,906	-469,5856519	170,7124365
Shut-in short after production	174,358	461,9035376	-170,1664538
Shut-in long after production	-110,786	-568,0833095	114,5586744
Start bullheading	-114,415	-589,2789768	118,1873726
Free string weight	0	-0,009216433	3,653254115

Table 5.2: Simulation done excel for resulting forces on packer for well "Y"

	[kN]	[kN]	[kN]
Load	**Tubing-to-packer force**	**Packer-to-casing force**	**Latching force**
Pressure test tubing	-142,501	-662,526522	145,7582028
Pressure test annulus/packer	39,78	490,5266201	-36,52214994
Early stage production	-168,711	-1117,183032	170,4150876
Steady stage production	-257,267	-1632,120329	259,0469637
Early stage injection	-373,316	-386,5322185	377,0285896
Steady stage injection	-384,908	-465,2278959	388,5287716
Shut-in short after production	-68,662	-259,0419042	71,97077916
Shut-in long after production	-229,859	-678,6454457	233,1641491
Start bullheading	-233,441	-699,786067	236,7462862
Free string weight	0	-0,002340681	3,174312909

5.2 Packer envelope

It is possible to evaluate a packer's design by looking at a performance envelope. A packer envelope produces a representation of a predictable safe zone for the packer by understanding the interaction of different loading conditions. The packer envelope is created by testing the packer in different conditions. The most important conditions to test the packer for is combined loading, pressure reversal, API casing tolerance, temperature, and fluid environment. Eventually, a packer testing will typically be done at 25°C, but must be adjusted for higher temperatures. Testing of combined loads is necessary for evaluating pressure differential with applied tensile and compressive loads. Each packer should also be subjected to pressure reversals. It is expected that it withstands pressure differential from below and above, and then below the packer. The API casing tolerance is to build a safety factor into the rating envelope. Here will various casing ID for any given casing weight be seen. The packer element system should be qualified and include verification of the seal. This can be done on maximum and minimum setting temperature. An effective cooldown temperature should also be verified through the test.

It is essential to evaluate all the possible loads that the well may be exposed to during the lifetime of the well. By simulating the most important loads when planning the well, it can be observed if the design will fit the requirements for the tested load cases. For the analyzed wells ”X” and ”Y”, it is possible to see if the critical loads fit the created rating envelope **4.4** for the packer. For well ”X” it is clear from the created rating envelope **5.1** that none of the load cases are outside the envelope:

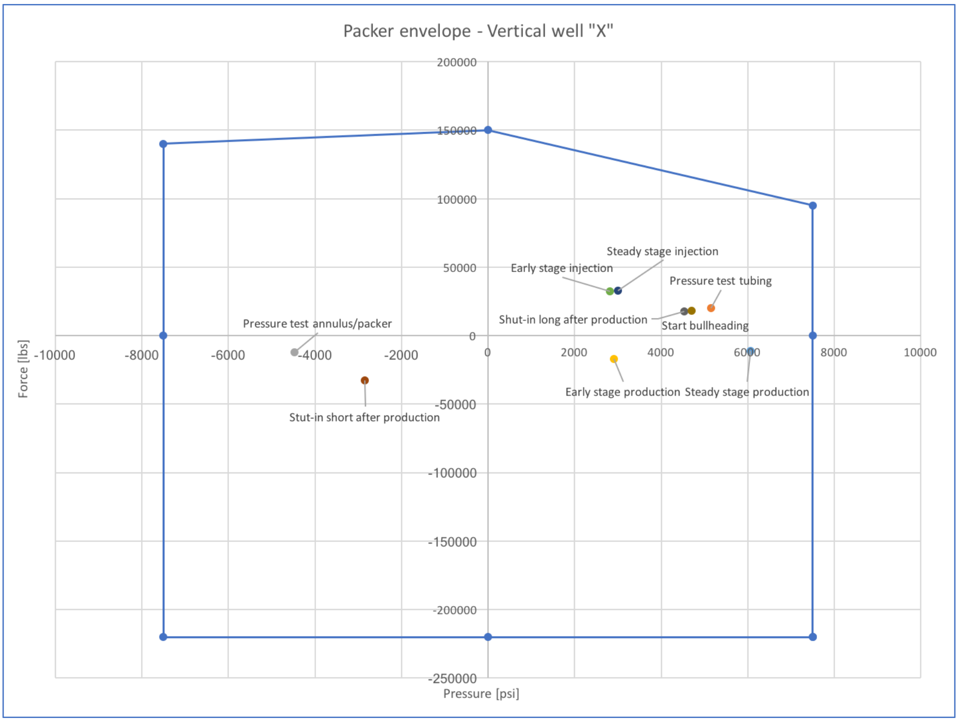

Figure 5.1: Packer envelope for well ”X”

For well ”Y” it can be observed from the packer envelope **5.2**, that “Steady stage production” and “Early stage production” are load cases which appear outside the envelope. To avoid that these load cases are outside the envelope, it can rather be used another packer with a bigger rating envelope or changes can be made in the software like WellCat for inputs values. This can be further investigated in more detail.

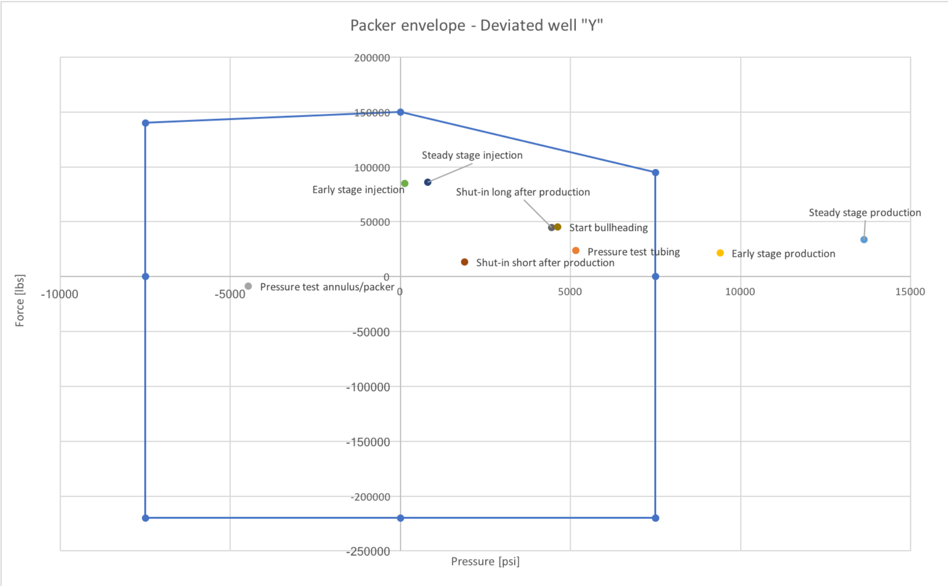

Figure 5.2: Packer envelope for well ”Y”

It is imperative to consider the load cases carefully since these are production loads which can create changes in conditions for the packer and the tubing. Early stages in a production consist of high flow rate. Since the fluids is produced from warmer surroundings, the tubing will be subjected to high thermal loads. This again will increase the temperature in annulus where the production packer is set. This will result in AFE as discussed in chapter 2. Careful consideration has to be done to get the loads “Steady stage production” and “Early stage production” to fit a given packer envelope and select the right packer that can withstand these effects and temperature changes.

5.3 Tubing design

Critical loads have been evaluated to determine an optimum tubing design. The tubing string will directly be subjected to different conditions in the well including loads from when testing the well during production, installation and killing the well. Combination loads from burst and collapse including axial loads can be critical for the tubing. This can cause tubing movement which causes length changes and buckling which is discussed in the next section. Moreover, it also causes axial forces in the well.

For each load cases simulated for well ”X” and ”Y”, design limit plots have been made which includes the triaxial forces along the tubing. As for the industry standard, the limiting criterion which is given by API standards and von Mises are also included in the plots. The simulated results is from the software WellCat and all the critical load cases are shown in the design limit plot.

The design limit plot **5.3** shows that for well "X" the most critical load case, which is the case that appears outside the von Mises ellipse, is the "Steady stage production".

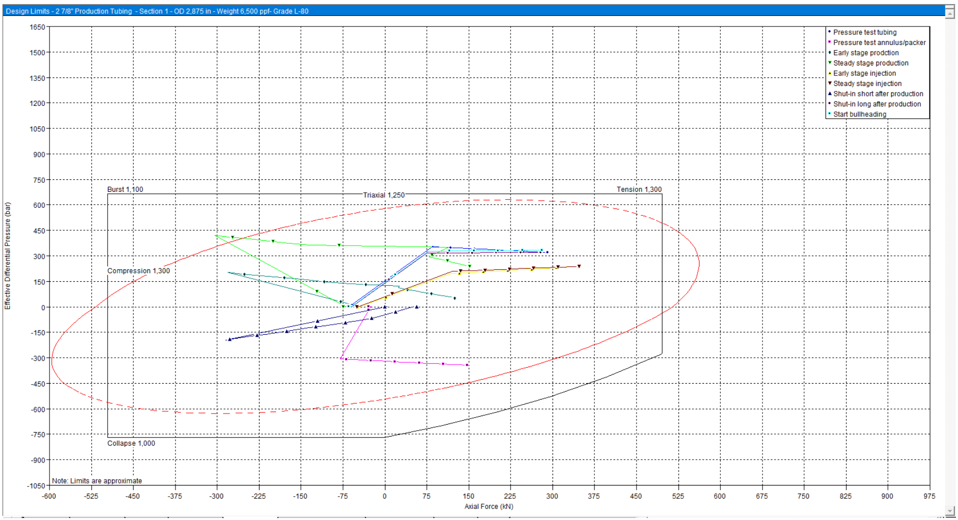

Figure 5.3: Design Limit Plot for the 2 7/8, L-80 Production Tubing - Well "X"

As discussed in section "Design strength of tubing" a higher graded tubing string can be chosen to fit the requirement for a well if needed. In this case, a new simulation with a higher grade tubing was done in WellCat. The chosen grade was P-105, and the result is shown in figure **5.4**.

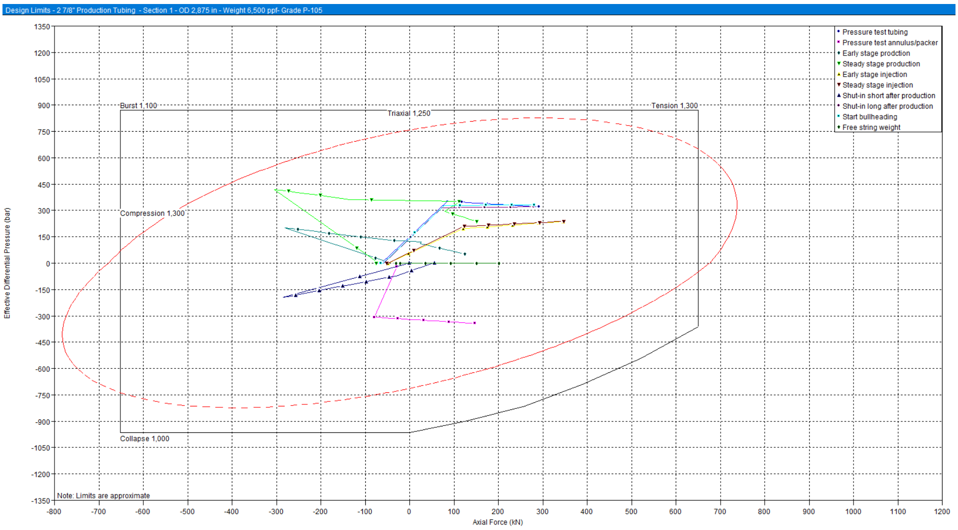

Figure 5.4: Design Limit Plot for the 2 7/8, P-105 Production Tubing - Well ”X”

After selecting a higher grade for the tubing, all load cases appears inside the design limit plot, for both the API and the von Mises criterion, which coincides with the theory.

In design limit plot for well ”Y”, the critical load cases are ”Steady stage production”, ”Early stage injection”, ”Steady stage injection” and ”Early stage production”. These load case must be inside the triaxial load capacity diagram as they are important production load cases for the tubing.

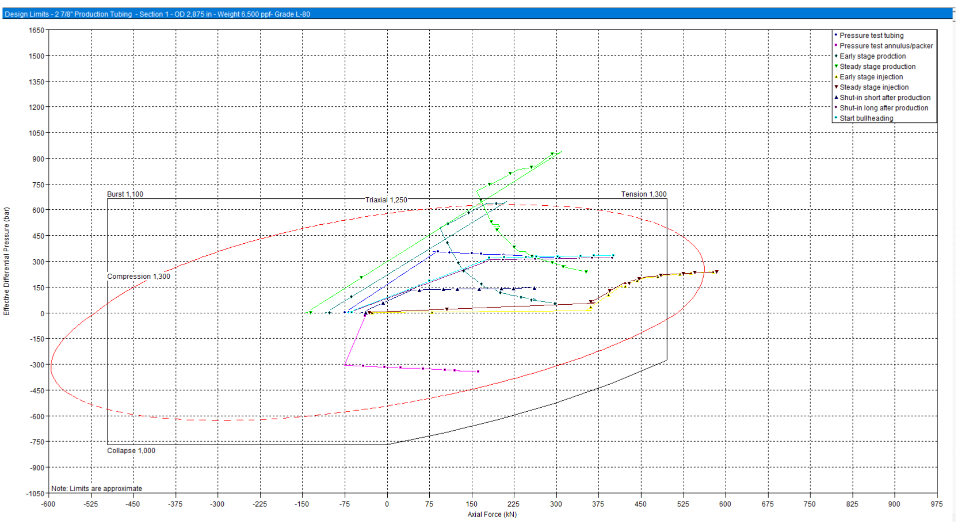

Figure 5.5: Design Limit Plot for the 2 7/8, L-80 Production Tubing - Well ”Y”

The same method is used to improve the plot by changing the grade of the tubing to P-105. The result is shown below:

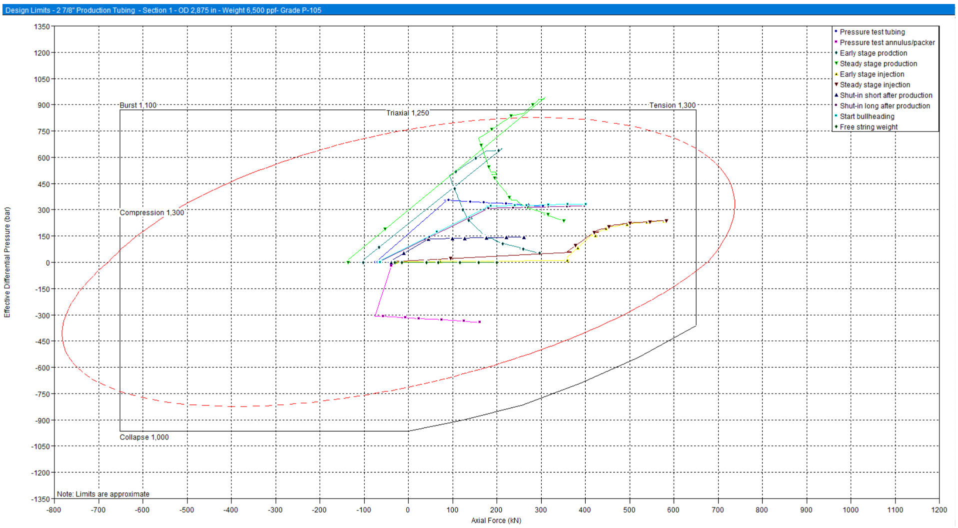

Figure 5.6: Design Limit Plot for the 2 7/8, P-105 Production Tubing - Well ”Y”

Figure **5.6** shows that the load cases ”Early stage injection”, ”Steady stage injection” and ”Early stage production” is now inside the design limit plot. However, ”Steady stage production” still appears outside the triaxial capacity diagram. Trying to fix this, it is essential to take a detailed look into the load case in Wellcat:

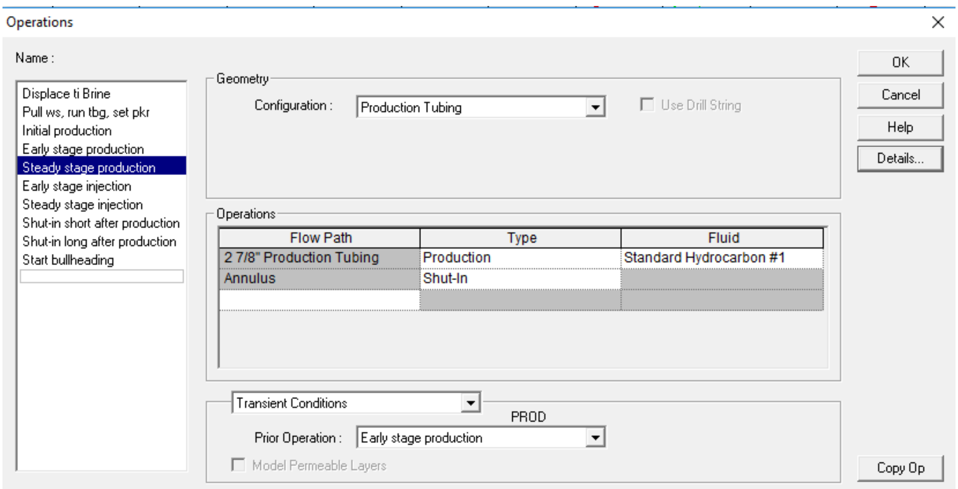

Figure 5.7: Steady stage production load detail taken from WellCat - I

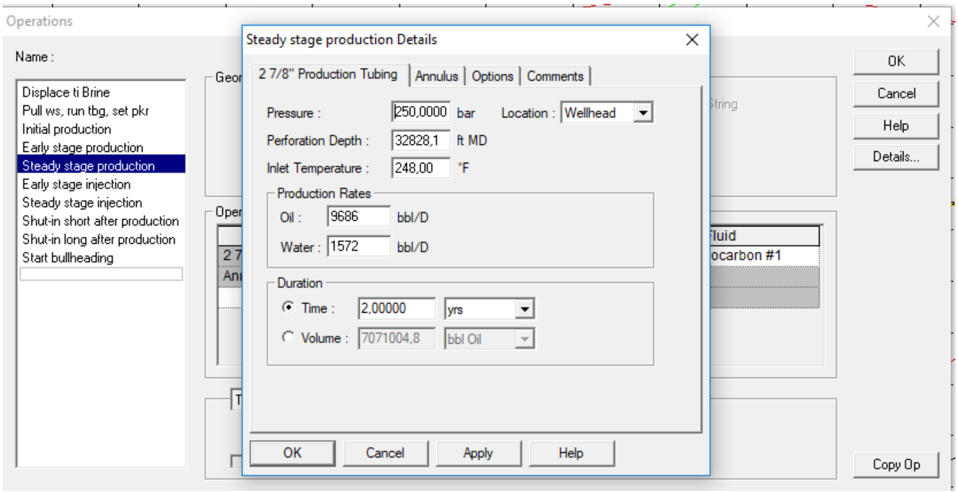

Figure 5.8: Steady stage production load detail taken from WellCat - II

After repeated attempts of trying and failing, finally the change in oil rate from 9686 bbl/D and water rate from 1572 bbl/D to respectively 8000 bbl/D and 1000 bbl/D appears to give an optimal result. The new input values are shown in figure **5.9**.

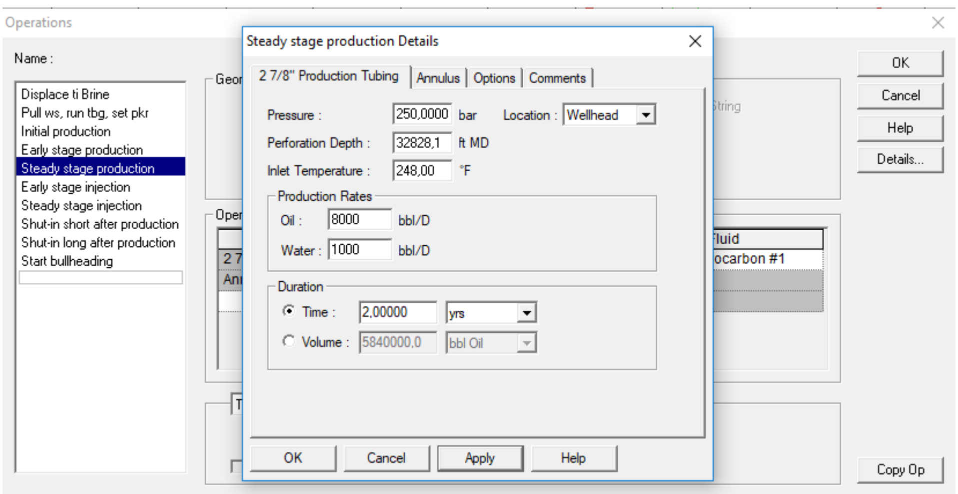

Figure 5.9: Steady stage production load detail taken from WellCat for new oil and water rates

The new design limit plot with a higher tubing grade and reduced oil and water production rates is given in figure **5.10**.

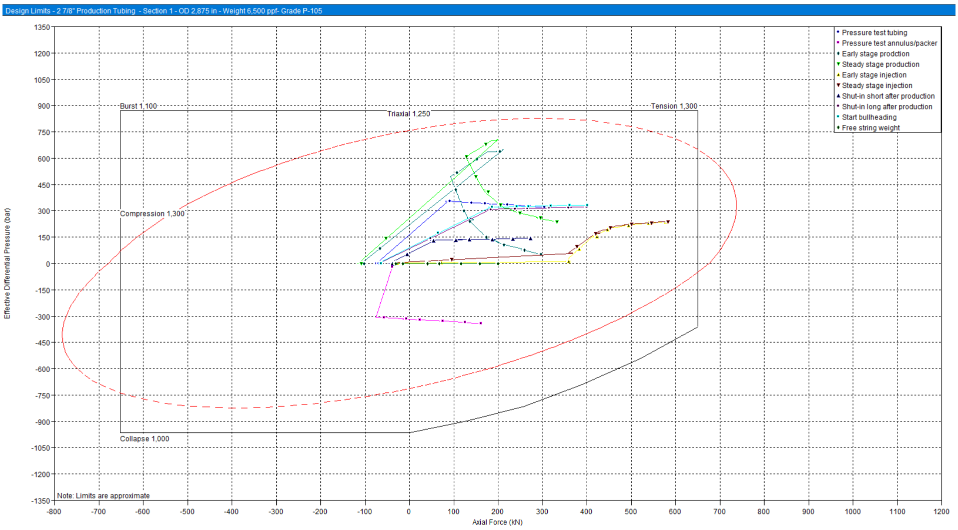

Figure 5.10: Design Limit Plot for the 2 7/8, P-105 Production Tubing - Well ”Y”

The result shows that all the critical load cases are inside the capacity diagram, which is one of the main goals to achieve a safe tubing design.

The results for both wells ”X” and ”Y” shows that a higher graded tubing may help to fit the requirements for the well. Further, the desired plot can be accomplished by changing input data. However, the economical part for when designing a well is as much as important, so changing the grade might not necessarily be the optimal solution. Therefore, the tubing design should be scrutinized, so alternative solutions that give cheaper results may be considered.

5.4 Tubing movement

In this thesis, tubing movement is measured based on length changes from the following effects:

- Thermal
- Ballooning
- Buckling
- Hooke’s law / Piston effect

The physical length changes due to thermal, ballooning and buckling effects is transferred through the material, while piston effect is described by the materials ability to strain.

For the vertical well simulated for tubing movement; Matlab, Excel and WellCat calculations are shown in the "Results" section. A tubing movement summary of the results was given by the table **5.3**:

Table 5.3: Tubing movement summary for the vertical well from WellCat, Matlab and Excel

Effect	**WellCat[inch]**	**Matlab[inch]**	**Excel[inch]**
Thermal	-16	-16,5600	-16,56
Ballooning	-34	-34,7946	-34,81
Buckling	-46	-46,0954	-46,17
Piston	-67	-67,8700	-67,91
Total length change	-165	-165,3200	-165,45

The results from the three simulators show the same result for each tubing movement effect for the vertical well. This can be interpreted that the simulators have the correct calculation method and equations to simulate load effects on a vertical well.

For the deviated well simulated for tubing movement; Matlab and WellCat calculations are shown in the "Results" section. A tubing movement summary of the results is shown in the following table:

Table 5.4: Tubing movement summary for the deviated well from WellCat and Matlab

Effect	**WellCat[inch]**	**Matlab[inch]**
Thermal	148,8	184,2921
Ballooning	-118,44	-149,4521
Buckling	-255,36	-143,6378
Piston	-243,12	-327,2056
Total length change	-468,12	-436,0034

The results from WellCat and Matlab differ from each other. The biggest difference is especially seen for the buckling effect. WellCat uses Lubinski's equation when calculating thermal, ballooning and piston effects. While for the buckling effect it uses Lubinski's and Mitchell's model for deviated wells. The Matlab code runs through Lubinski and Aadnøy's equation for thermal, ballooning and piston effect. In addition, it uses Mitchell's equation when calculating the buckling effect for deviated wells.

The simulation of the horizontal well gives a more complex result than for the vertical well as both softwares are based on different theories. The output of buckling effect in WellCat can be interpreted as a conservative analysis for the deviated well. The Matlab code is an improved model for buckling effect and includes the latest theory and is therefore more trustworthy.

Chapter 6

Conclusion

- Resulting packer forces for the wells ”X” and ”Y” have been computed using a comprehensive calculator. The results correspond with the simulated data in WellCat^{TM}.

- Packer envelope is an important development, which represents a predictable safe operating zone for a production packer. The area outside the performance envelope is beyond the calculated safe operating zone. The results show that for well ”X”, all the load cases are inside the packer envelope in the safe operating zone. While for well ”Y”, two load cases appeared outside the fictitious performance envelope. This can be interpreted as that the selected packer for well ”X” will withstand all critical load cases. Whereas for well ”Y”, the selected packer will not withstand these load cases. To keep the load cases inside the envelope, another packer with a bigger rating envelope should be considered for well ”Y”.

- Defining initial conditions accurately is important when load cases are simulated in WellCat. This is because all other load cases are based on this load case. If the base case is incorrect, it will affect the output for the other simulated cases. In this thesis, the main factors that are dependent on correct initial conditions, are length changes in the well, load cases and tubing-to-packer forces which are given by the change from the initial condition.

- Well integrity is an essential aspect for safety and regularity in production. A fundamental part of well integrity is the primary and secondary barrier envelope. In this thesis, production tubing is discussed in detail, including elements of the production packer. The production tubing should be able to bear the weight of the entire completion and withstand length changes due to pressure and temperature variations in the well. In the completion, other components that have been installed will have the same requirements for strength as the production pipe. The production packer separates the barrier envelopes and enables continuous monitoring of the barriers, which prevents unwanted leakage from the reservoir environment.

- This thesis aimed to identify potential critical load cases that may affect the tubing when producing. By analyzing design limit plots for both wells ”X” and ”Y”, the results indicate that some of the load cases appeared outside the plot for both wells. For well ”X” changing to a higher tubing grade, made the load cases appear inside the triaxial capacity diagram. While for well ”Y”, a higher graded tubing and a lower production rate was required to have a safe operating zone.

- If tubing movement is allowed, potential elongation or shortening effects gives length changes in the tubing. The length changes for thermal, piston and ballooning effect were found to be the same for the vertical well and all the three softwares tested on. While for the deviated well, the effects gave slightly different outputs in WellCat and Matlab, but not big enough to a further enquiry.

- Compressive forces and imperfections in the geometry affect the likelihood of buckling. WellCat is found to perform conservative buckling analysis for deviated wells. As a result, buckling effects were computed by an improved model from Remmen (2018) with the latest theory. This model is modified to be applicable for all well designs and was used to estimate the right buckling effect for the deviated well.

Chapter 7

Further work

- To create a more economical tubing design and protecting the integrity of the well, further work can include improvement of the design limits plot. This can be improvements based on industry practice.
- In this thesis, tubing design was developed for a vertical and a deviated well. Additional work can include applying models and investigation of the difference in packer loads, load cases and length changes caused by temperature effects, in addition, a more detail look on annular fluid expansion.
- A further study of buckling effect can be conducted to get a broader overview of tubing behaviour in deviated wells.
- More depth analysis of how the different effects on tubing and production packer react to different load case scenarios can be useful to find. This will give a better understanding of how the forces are distributed, and why the different load cases go outside a packer envelope and design limit plot. By investigating the critical load cases it will make it easier to choose correct tubing and packer design.
- The WellCat software tool has some other functional limitations that should be corrected or improved. This can further be discussed in details.
- Investigation of the tubing condition from installation to further operations. This can help understanding factors like tubing grade, wear, and corrosion from the installation process.

Nomenclature

e	=	Absolute pipe roughness
A	=	Area
A	=	Area of plane the heat moves through
$\overline{Z}$	=	Average gas comparability factor
h	=	Average heat transfer coefficient
P_R	=	Average reservoir pressure
$\overline{T}$	=	Average temperature
$temp_{avg,f}$	=	Average temperature, final condition
$temp_{avg,init}$	=	Average temperature, initial condition
σ_z	=	Axial stress
P_{wf}	=	Bottomhole flowing pressure
F_b	=	Buoyancy force
w	=	Buoyed tubing weight
DF_{burst}	=	Burst design factor
CO_2	=	Carbon dioxide
$DF_{collapse}$	=	Collapse design factor
P_c	=	Collapse pressure resistance
F_c	=	Critical force
A_s	=	Cross sectional area
$\rho_{i,f}$	=	Density inside, final condition
$\rho_{i,init}$	=	Density inside, initial condition
$\rho_{o,f}$	=	Density outside, final condition
$\rho_{o,init}$	=	Density outside, initial condition
Δp	=	Differential pressure
F_{eff}	=	Effective buckling force
p_o	=	External pressure
Δp_o	=	External pressure change
$F\circ$	=	Fahrenheit
ρ_{fluid}	=	Fluid density
F	=	Force
F_{kN}	=	Force in kN
ΔF_{piston}	=	Force change generated by piston force
$F_{ballooning}$	=	Force due to ballooning
F_{temp}	=	Force generated by temperature
f	=	Friction factor
q_g	=	Gas flow rate
G_g	=	Gas gravity
q_x	=	Heat flux in x-direction per unit area
h	=	Height
H_2S	=	Hydrogen sulphide

A_i	=	Inner area of tubular
$A_{i\text{-}t}$	=	Inner area of tubular
ID	=	Inner diameter
ID_c	=	Inner diameter casing
ID_t	=	Inner diameter tubing
r_i	=	Inner wall radius
p_i	=	Internal pressure
Δp_i	=	Internal pressure change
p_i	=	Internal pressure of tubular
L	=	Length
$\Delta L_{ballooning}$	=	Length change due to ballooning
ΔL_{piston}	=	Length change due to piston
ΔL_{temp}	=	Length change due to temperature
L	=	Length of tubing
P_b	=	Minimum burst pressure
Y_p	=	Minimum yield strength
Y_p	=	Minimum yield stress
I	=	Moment of inertia
ρ_{mud}	=	Mud density
D	=	Nominal OD
t	=	Nominal wall thickness
A_o	=	Outer area of tubular
$A_{o\text{-}t}$	=	Outer area of tubular
OD	=	Outer diameter
OD_t	=	Outer diameter tubing
p_o	=	Outer pressure of tubular
r_o	=	Outer wall radius
A_p	=	Packer bore area
F_{pc}	=	Packer-to-Casing Force
ρ_{pipe}	=	Pipe density
μ	=	Poisson's ratio
p	=	Pressure
σ_r	=	Radial stress
r	=	Radius
D/t	=	Slenderness ratio
σ	=	Stress
$ps_{i,f}$	=	Surface pressure inside, final condition
$ps_{i,init}$	=	Surface pressure inside, initial condition
$ps_{o,f}$	=	Surface pressure outside, final condition
$ps_{o,init}$	=	Surface pressure outside, initial condition

σ_θ	=	Tangential(hoop) stress
T_P	=	Tension required to set the packer
ΔT	=	Temperature change
dT/dx	=	Temperature gradient
T_∞	=	Temperature of the flowing fluid
T_S	=	Temperature of the surface
k	=	Thermal conductivity
C_T	=	Thermal expansion coefficient
F_{total}	=	Total axial load
σ_{VME}	=	Triaxial stress
D	=	Tubing diameter
F_{pt}	=	Tubing-to-Packer Force
H	=	Vertical depth
w	=	Weight of tubing
P_{wh}	=	Wellhead flowing pressure
P_{Yp}	=	Yield pressure
E	=	Young's modulus

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Appendix A

Tubing Stress Analysis

A.1. Design factor

Tubing strings should be designed properly to cover all anticipated load cases during the lifecycle of the well. To select the appropriate tubing with the correct weight and grade, the concept about design factor in tubular design is essential to understand.

Design factor describes the design intensity to ensure that the tubular will have addition load to cover all load cases. The design factor can be expressed by the following formula, Bellarby (2009a):

$$\text{Design Factor(DF)} = \frac{\text{Pipe Rating}}{\text{Expected Load}}$$

A design factor of 1 is what a tubular can withstand before it starts to yield. Tensile loads, burst loads, collapse loads, triaxial loads, drilling loads, production loads, axial loads, running and cementing loads and service loads are all examples of anticipated load cases. Each company have their own standard when it comes to design factor and to meet the required well. The following table shows general design factors used in the industry:

Table 7.1: Typical design factors used in the industry

Failure Mode	**Design Facor**
Burst	1.1 - 1.25
Collapse	1.0 - 1.1
Axial	1.3 - 1.6
Triaxial	1.2 - 1.3

A.2 Safety Factor

Safety factor can be described in the similar way as the design factor. The difference is that safety factor can be more than or equal to the design factor. The minimal safety factor will be equal to the design factor. The relationship between the safety factor and design factor can therefore be explained by the equation below, Bellarby (2009a):

$$\text{Design Factor(DF)} = \text{Safety Factor (SF)}_{\text{min}} \leq \text{Safety Factor (SF)}\frac{\text{Pipe Rating}}{\text{Expected Load}}$$

A.3 Material properties

When looking at the safety aspect of a well it is essential to understand the mechanical properties of the tubulars. If a failure occurs during a completion operation, it can cause catastrophic problems. This can be major losses like production from the well, damage on the equipment and also safety of personal. The following section will describe basic mechanical properties which are fundamental to understand when designing a tubular.

Stress

Stress, σ is force applied per unit area, Bellarby (2009a):

$$\sigma = \frac{\text{Force}}{\text{Area}}$$

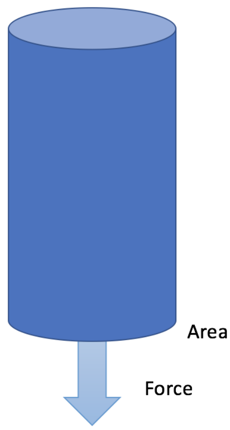


Figure 7.1: Illustration of stress on a tubular

where,
σ = stress of material

Strain

A tubular can be subjected to loads that makes the tubular long. This load is referred to as tensile load and the elongation it makes is called "strain", ε. Strain can be expressed as, Bellarby (2009a):

$$\varepsilon = \frac{\Delta \text{L}}{\text{L}}$$

where,
ε = strain of material

L = length of tubular
ΔL = length change of the tubular

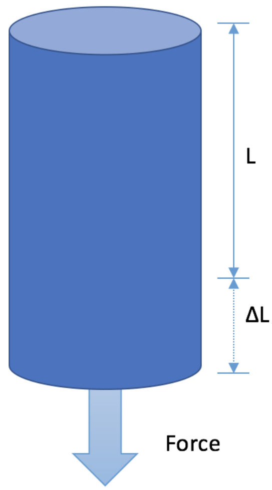


Figure 7.2: Illustration of strain on a tubular

Elasticity

Tubulars are made of steel, and steel is a ductile material which can have elastic behaviour. Elasticity is a property of the material which allows the material to return to its original shape when the load is released. Stress and strain can be described by an equation where the material is under elastic limit, Bellarby (2009a):

$$\sigma = \mathrm{E} \cdot \varepsilon$$

where,
E = young's modulus (Modulus of elasticity)

For steel, young's modulus of elasticity is about $30{\cdot}10^6$ psi. When a material is exposed to a force, strain and stress can be plotted in a stress-strain curve like in figure **7.3**. It is essential to understand the meaning of the given points in the stress-strain plot.

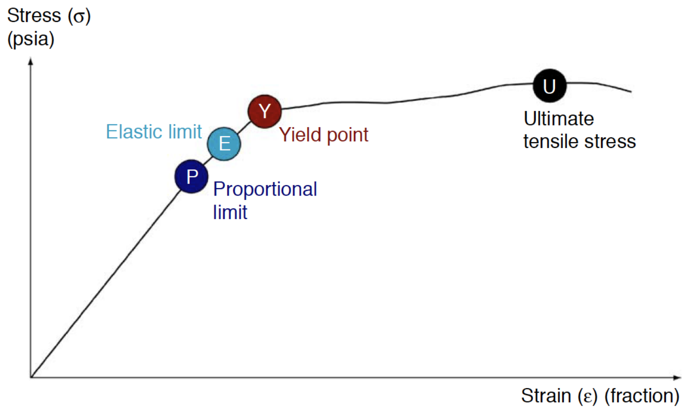


Figure 7.3: Typical stress and strain curve for a tubular, Bellarby (2009a)

From the figure above, the elastic region can be defined from the origio till the yield point. While the plastic region is described from the yield point til the end of the curve, which can be defined as the failure point where the material will be parted.

If the material is within the elastic region, it will go back to its original shape when the force is released. Under the plastic region, the material will be plastically deformed and the stress and strain is under Hooke's law.

The proportional limit point illustrates where stress is a proportional limit to strain. The elastic limit point is where stress and strain have a linear relationship. While the yield point is the maximum stress the material can withstand before it is plastically deformed. After this point, the material will not be able to come back to its original shape. The ultimate tensile stress describes the point where the material can withstand the maximum stress and is the top point of the stress-strain curve.

Poisson's Ratio

When axial and radial strain is present, the material is under tension. When both these strains are in the elastic region, they will be proportional to each other. This relationships is called poisson's ratio, μ, Bellarby (2009a):

$$\mu = -\frac{\text{radial strain}}{\text{axial strain}} = \frac{\Delta t/t}{\Delta L/L}$$

Ductile and brittle material

Ductile material is a material type which has a large degree of plastic deformation before fracturing the component. Carbon steel is an example of a ductile material. Brittle material has on the other hand low degree of plastic deformation.An example of a brittle material is grass. This means that after yield strength is exceeded the brittle material will break apart easily, while the ductile material will elongate first before it gets parted.

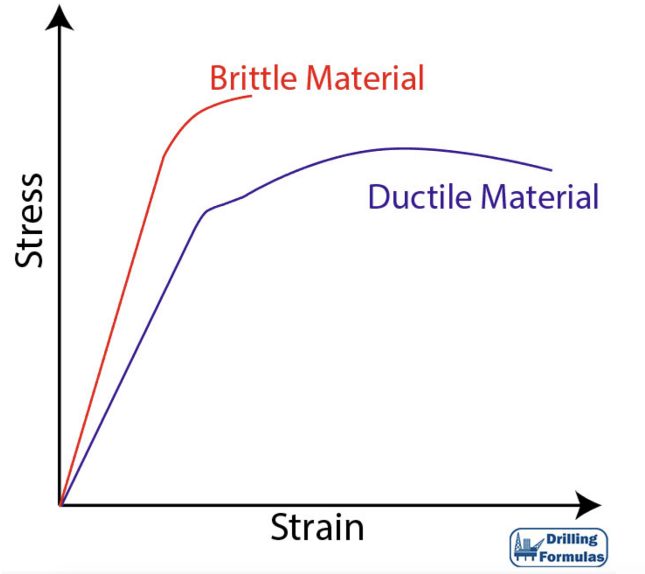


Figure 7.4: Curve showing the behaviour of ductile and brittle material, DrillingFormulas (2016c)

Appendix B

Different load effects on tubing and production packer

B.1. Thermal effect

Example calculation

The following example will demonstrate the method of calculating tubing length change caused by change in temperature:
Well data for a vertical well which allows the tubing move:

- Packer setting depth: 10 000 ft = 120 000 inch
- C_T: $6.9 \cdot 10^{-6}$ (1/F)

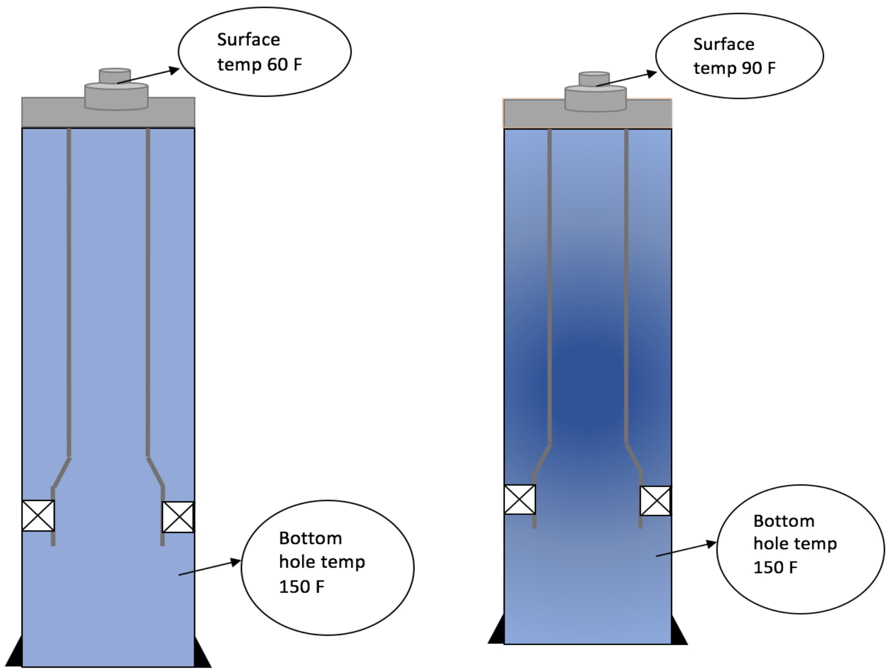
Data at the initial condition:

- Surface temperature: 60F
- Bottomhole temperature: 150F

Data at the final condition:

- Surface temperature: 90F

- Bottomhole temperature: 150F



(a) Initial condition **(b)** Finial condition

This problem can be solved by calculating the average temperature at both the initial and final condition:

$$\text{Average temperature at the initial condition} = \frac{60 + 150}{2} = 105\text{F} \tag{7.1}$$

$$\text{Average temperature at the final condition} = \frac{90 + 150}{2} = 120\text{F} \tag{7.2}$$

The next step is to determine the temperature change in total, ΔT:

$$\Delta\text{T} = 120 - 105 = 15\text{F} \tag{7.3}$$

Finally, the change in length can be estimated by using equation (1.3) and inserting the numbers found:

$$\Delta L_{temp} = 6,9 \cdot 10^{-6} \cdot 120000 \cdot 15 = \underline{\underline{12,42\text{inch}}} \tag{7.4}$$

→ The result shows a positive value, which means that an increase in temperature leads to an increase in the length of the tubing string, with 12.42 inches.

Excel calculation

Thermal effect						
Well data	Lubinski's example - vertical well		Deviated well		Example	
Packer setting depth [ft]/[inch]						
	10000	120000	29000	348000	10000	120000
Thermal expansion coefficient						
	0,0000069		0,0000069		0,0000069	
Young's modulus						
	30000000		30000000		30000000	
Inner diamter tubing [inch]						
	2,441057367		2,441		3,862	
Outer diamter tubing [inch]						
	2,875		2,875		4,5	
Inner area tubing [inch^2]						
	4,68		4,679780034		11,71424816	
Outer area tubing [inch^2]						
	6,491806694		6,491806694		15,90431281	
Cross sectional area of tubing, As [inch^2]						
	1,811806694		1,81202666		4,190064644	
Average temperature change [F]						
At initial condition	155		159,9		105	
At finial condition	135		236,65		120	
Temperature change in total	-20	cooling	76,75	heating	15	
Length of tubing [ft]/[inch]	10000	120000	29000	348000	10000	120000
Initial condition	Lubinski's	Deviated	Example			
Surface temperature [F]	80	80	60			
Bottomhole temperature [F]	230	239,8	150			
Finial condition						
Surface temperature [F]	60	233,4	90			
Bottomhole temperature [F]	210	239,9	150			
FINAL RESULT						
Length change due to thermal effect	**Δtemp[inch]**	-16,56	184,2921	12,42		

B.2 Ballooning effect

Example calculation

This effect can easily be illustrated by an example. Well data for a vertical well, where tubing and seal bore is free to move.

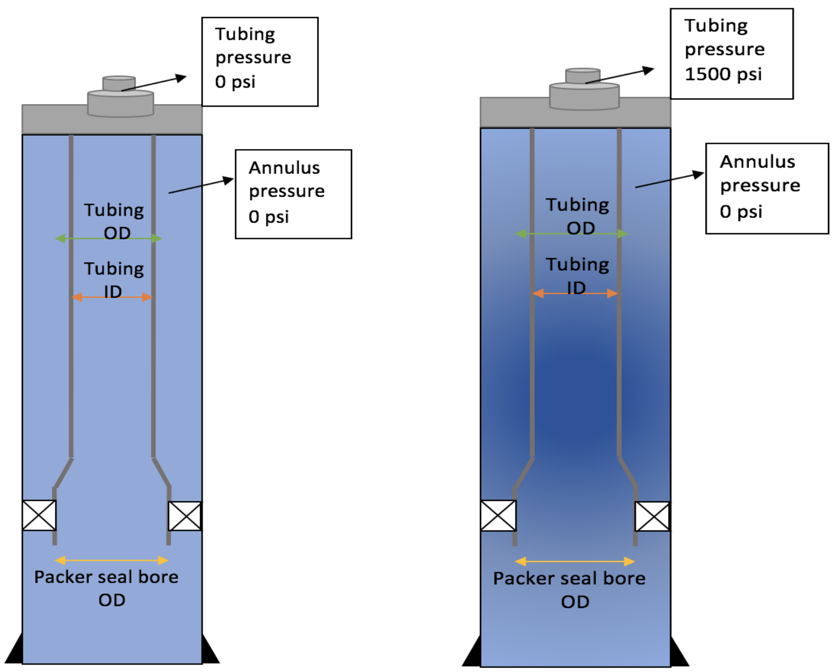
- Packer setting depth: 10 000 ft = 120 000 inch
- Tubing: 4,5”
- ID of tubing: 3,862”
- Packer seal bore OD: 5,0”
- Weight per length of tubing: 17,7 lb/ft
- Young’s modulus(E): $30{\cdot}10^6$
- Poisson’s ratio(μ): 0,3

Data for initial condition:

- Fluid in tubing: 10,0 ppg
- Fluid in annulus: 10,0 ppg
- Tubing pressure: 0 psi
- Annulus pressure: 0 psi

Data for final condition:

- Fluid in tubing: 8,0 ppg
- Fluid in annulus: 10,0 ppg
- Tubing pressure: 1500 psi
- Annulus pressure: 0 psi



(a) Initial condition　　**(b)** Finial condition

A stepwise calculation is shown to determine the change in length due to ballooning.

1. The first step would be to calculate the cross sectional areas:

$$\mathrm{A_i} = \frac{\pi}{4} \cdot 3,862^2 = 11.497\mathrm{in}^2 \tag{7.5}$$

$$A_o = \frac{\pi}{4} \cdot 4,5^2 = 15,904 \mathrm{in}^2 \tag{7.6}$$

2. The second step is to determine average pressure at initial condition:

$$p_o \text{ at surface} = 0\text{psi}$$

$$p_i \text{ at surface} = 0\text{psi}$$

$$\begin{aligned} p_o \text{ at packer} &= p_o \text{ at surface} + \text{Hydrostatic p in annulus} \\ &= 0 + (0,052 \cdot 10 \cdot 10000) = 5200\text{psi} \end{aligned}$$

$$\begin{aligned} p_i \text{ at packer} &= p_i \text{ at surface} + \text{Hydrostatic p in tubing} \\ &= 0 + (0,052 \cdot 10 \cdot 10000) = 5200\text{psi} \end{aligned}$$

$$p_o \text{ at initial condition} = \frac{(0 + 5200)}{2} = 2600\text{psi} \tag{7.7}$$

$$p_i \text{ at initial condition} = \frac{(0 + 5200)}{2} = 2600\text{psi} \tag{7.8}$$

3. The third step is to estimate the average pressure at the final condition:

$$p_o \text{ at surface} = 0\text{psi}$$

$$p_o \text{ at surface} = 0\text{psi}$$

$$\begin{aligned} p_o \text{ at packer} &= p_o \text{ at surface} + \text{Hydrostatic p in annulus} \\ &= 0 + (0,052 \cdot 10 \cdot 10000) = 5200\text{psi} \end{aligned}$$

$$\begin{aligned} p_i \text{ at packer} &= p_i \text{ at surface} + \text{Hydrostatic p in tubing} \\ &= 1500 + (0,052 \cdot 8 \cdot 10000) = 5660\text{psi} \end{aligned}$$

$$p_o \text{ average at initial condition} = \frac{(0 + 5200)}{2} = 2600\text{psi} \tag{7.9}$$

$$p_i \text{ average at initial condition} = \frac{(1500 + 5660)}{2} = 3580\text{psi} \tag{7.10}$$

Finally the pressure change, Δp is estimated:

$$\Delta p_o = 2600 - 2600 = 0\text{psi} \tag{7.11}$$

where Δp_o shows the change in average annulus pressure and Δp_i shows the change in average tubing pressure:

$$\Delta p_i = 3580 - 2600 = 980\text{psi} \tag{7.12}$$

The final step is to use (2.14) and insert the numbers estimated.
$\rightarrow$ The result for the length change due to ballooning is a decrease of length by 6,14 inches:

$$\Delta L_{\text{ballooning}} = -\frac{2 \cdot 0,3 \cdot 120000}{30 \cdot 10^6 \cdot (15,904 - 11.497)} \cdot (11.497 \cdot 980 - 15,904 \cdot 0) \tag{7.13}$$

$$= \underline{\underline{-6,14\text{inch}}} \tag{7.14}$$

Excel calculation

Ballooning effect						
Well data	Lubinski's example - vertical well		Deviated well		Example	
Packer setting depth [ft]						
	10000	120000	29000	348000	10000	120000
Poisson's ratio						
	0,3		0,3		0,3	
Young's modulus						
	30000000		30000000		30000000	
Inner diameter tubing [inch]						
	2,441057367		2,441057367		3,862	
Outer diamter tubing [inch]						
	2,875		2,875		4,5	
Inner area tubing [inch^2]						
	4,68		4,68		11,71424816	
Outer area tubing [inch^2]						
	6,491806694		6,491806694		15,90431281	
At inital condition [psi]						
Outer pressure at packer	3794,48		11025,016		5200	
Inner pressure at packer	3794,48		11025,016		5200	
Average outer pressure of tubular	1897,26		5512,523		2600	
Average inner pressure of tubular	1897,26		5523,078		2600	
At final condition [psi]						
Outer pressure at packer	4794,44		11024,696		5200	
Inner pressure at packer	12800		25182,14		5660	
Average outer pressure of tubular	2897,22		5522,758		2600	
Average inner pressure of tubular	8900		13872,14		3580	
Average annulus pressure change, DeltaPo	999,96		10,235		0	
Average tubing pressure change, DeltaPi	7002,74		8349,062		980	
Initial conditon	Lubinski's		Deviated	Example		
[ppg]						
Fluid in tubing	7,297	30 degree API	7,297	10		
Fluid in annulus	7,297		7,297	10		
[psi]						
Tubing pressure	0,04		21,14	0		
Annulus pressure	0,04		0,03	0		
Final condition						
[ppg]						
Fluid in tubing	15		15	8		
Fluid in annulus	7,297		7,297	10		
[psi]						
Tubing pressure	5000		2562,14	1500		
Annulus pressure	1000		20,82	0		
FINAL RESULT						
Length change due to ballooning effect	Δlballooning [inch]	-34,81335124	-149,8448371	-6,5755338		

B.3 Piston effect

Example calculation

To illustrate this with one example, the exact welldata and calculations are taken from the previous examples. Since most of the calculations are done in the other examples, the remaining is to estimate the packer seal bore area, which is:

$$\mathrm{A_p} = \frac{\pi}{4} \cdot 5^2 = 19,635 \mathrm{in}^2 \tag{7.15}$$

Cross sectional area of tubing:

$$\mathrm{A_s} = \mathrm{A_0} - \mathrm{A_i} = 15,904 - 11,497 = 4,407 \mathrm{in}^2 \tag{7.16}$$

Change in annulus pressure at packer:

$$\Delta p_o = 5200 - 5200 = 0\text{psi} \tag{7.17}$$

Change in tubing pressure at packer

$$\Delta p_i = 5660 - 5200 = 460\text{psi} \tag{7.18}$$

Finally the force change, ΔF_{piston} is estimated using equation (2.20)

$$\Delta F_{piston} = (19,635 - 11,497) \cdot 460 - (19,635 - 15,904) \cdot 0 = \underline{\underline{3744\text{lbs}}} \tag{7.19}$$

→ This describes a compression force, as the it is a positive value.

In the same way, the length change can be estimated by using equation (2.21):

$$\Delta L_{piston} = -\frac{12000 \cdot 03744}{30 \cdot 10^6 \cdot 4,407} = \underline{\underline{-3,4\text{inch}}} \tag{7.20}$$

→ Which means tubing is shorter length by 3.4 inch.

Excel calculation

Piston effect						
Well data	Lubinski's example - vertical well		Deviated well		Example	
Packer setting depth [ft]/[inch]						
	10000	120000	29000	348000	10000	120000
Young's modulus						
	30000000		30000000		30000000	
Inner diamter tubing [inch]						
	2,441057367		2,441057367		3,862	
Outer diamter tubing [inch]						
	2,875		2,875		4,5	
Packer seal bore outer diamter [inch]						
	3,25		3,25		5	
Inner area tubing [inch^2]						
	4,68		4,68		11,71424816	
Outer area tubing [inch^2]						
	6,491806694		6,491806694		15,90431281	
Packer seal bore area [inch^2]						
	8,295768101		8,295768101		19,63495408	
Cross sectional area tubing [inch^2]						
	1,811806694		1,811806694		4,190064644	
At initial conditon [psi]						
Outer pressure at packer	3794,44		11003,906		5200	
Inner pressure at packer	3794,44		11025,016		5200	
At finial condition [psi]						
Outer pressure at packer	4794,44		11024,696		5200	
Inner pressure at packer	12800		25182,14		5660	
Change in annulus pressure at packer [psi]						
	1000		20,79		0	
Change in tubing pressure at packer [psi]						
	9005,56		14157,124		460	
Inital condition	Lubinski's	Deviated	Example			
[ppg]						
Fluid in tubing	7,297	7,297	10			
Fluid in annulus	7,297	7,297	10			
[psi]						
Tubing pressure	0	21,14	0			
Annulus pressure	0	0,03	0			
Finial condition						
[ppg]						
Fluid in tubing	15	15	8			
Fluid in annulus	7,297	7,297	10			
[psi]						
Tubing pressure	5000	2562,14	1500			
Annulus pressure	1000	20,82	0			
FINAL RESULT						
Lenght change due to piston effect	ΔLpiston [inch]	-67,90582079	-327,4940581	-3,47825156		
Force change due to piston effect	ΔFpiston [lbs]	30758,05517	51151,373	3643,52472		

B.4 Buckling effect

Excel calculation

Buckling effect						
Well data	Lubinski's example - vertical well		Deviated well		Example	
Packer setting depth [ft/inch]	10000	120000	29000	348000	10000	120000
Young's modulus	30000000		30000000		30000000	
Inner diamter tubing [inch]	2,441057367		2,441057367		3,826	
Outer diameter tubing [inch]	2,875		2,875		4,5	
Packer seal bore outer diamter [inch]	3,25		3,25		5	
Inner diamter production casing [inch]	6,095		6,095		6,049	
Inner area tubing [inch^2]	4,68		4,68		11,49687509	
Outer area tubing [inch^2]	6,491806694		6,491806694		15,90431281	
Packer seal bore area [inch^2]	8,295768101		8,295768101		19,63495408	
At final condition [psi]						
Outer pressure at packer	4794,44		11024,696		5200	
Inner pressure at packer	12800		25182,14		5660	
Fictitious force, Ff [lbs]	66412,26928		117446,8723		9032,078879	
Density of fluid in the tubing [lb/inch^3]	0,064935		0,064935		0,034632	
Density of fluid ion the annulus [lb/inch^3]	0,031588713		0,031588713		0,04329	
Weight og tubing per feet [lb/ft]	6,5		6,5		15,5	
Weight per unit length of tubular in the prences of fluid, W [lb/inch]						
Weight per unit weight of steel, Ws	0,541666667		0,541666667		1,291666667	
Weight per unit weight of fluid insude tubing, Wi	0,3038958		0,3038958		0,398159778	
Weight per unit weight of fluid outside tubing, Wo	0,205067819		0,205067819		0,688497701	
W	0,640494648		0,640494648		1,001328743	
Location of neutral point, n [ft]	8640,752564		15280,7512		751,6744576	
Length of tubing [inch]	120000		348000		120000	
Radial clearance between tubing OD and casing ID, r [inch]	1,61		1,61		0,7745	
Moment of inertia of tubing cross section, I [inch^2]	1,610739869		1,610739869		9,610493984	
Initial condition	Lubinski's	Deviated	Example			
[ppg]						
Fluid in annulus	7,297	7,297	10			
Fluid in tubing	7,297	7,297	10			
[psi]						
Tubing pressure	0	21,14	0			
Annulus pressure	0	0,03	0			
Final condition						
[ppg]						
Fluid in annulus	7,297	7,297	10			
Fluid in tubing	15	15	8			
[psi]						
Tubing pressure	5000	2562,14	1500			
Annulus pressure	1000	20,82	0			
FINAL RESULT						
Length change due to buckling	**ΔLbuckling [inch]**	-46,17386586	-144,4050922	-0,0211877		

B.5 Matlab Code for all load effects

Inputs

```
clc
clear all

tic
```

```
% Tubing Inputs
OD         = 2.875;                      %in     outer diameter
weight     = 6.5;                        %lb/ft  dry weight
ID         = 2.441;                      %in     inner diameter
grades     = 10^3.*[40 55 75 80 105];    %psi    yield strength
E          = 30*10^6;                    %psi    Young's modulus
poisson    = 0.3;                        %       Poisson's ratio
Ct         = 6.9*10^(-6);                %/F     coeff. of thermal expansion
Lp         = 10000*12;                   %in     tubing length
Dp         = 3.25;                       %in     packer bore diameter

Ao         = pi/4*OD.^2;                 %in2    outer area
Ai         = pi/4*ID.^2;                 %in2    inner area
As         = Ao-Ai;                      %in2    cross-sectional area
Ap         = pi/4*Dp^2;                  %in2    packer bore area
R          = OD./ID;                     %ratio  OD/ID-ratio
ws         = weight./12;                 %lb/in  dry weight of tubing
I          = (pi/64)*(OD.^4-ID.^4);      %in4    moment of inertia

% Casing Inputs
csgOD      = 7;                          %in     outer diameter
csgweight  = 32;                         %lb/ft  dry weight
csgID      = 6.094;                      %in     inner diameter
rc         = (csgID-OD)/2;               %in     radial clearance

% Fluid Properties
rhot       = 1/231*[7.297 15];           %psi/in tubing initial-final
rhoa       = 1/231*[7.297 7.297];        %psi/in annulus initial-final
drhot      = rhot(2)-rhot(1);            %psi/in tubing change in density
drhoa      = rhoa(2)-rhoa(1);            %psi/in annulus change in density
wi         = rhot.*Ai;                   %lb/in  tubing initial-final
wo         = rhoa.*Ao;                   %lb/in  annulus initial-final
w          = ws + wi - wo;               %lb/in  total initial-final

% Pressures
pi         = [0 5000];                   %psi    surface initial-final
po         = [0 1000];                   %psi    surface initial-final
Pi         = pi+rhot*Lp;                 %psi    packer initial-final
Po         = po+rhoa*Lp;                 %psi    packer initial-final
```

```
dp        = [pi(2)-pi(1) po(2)-po(1)];  %psi    change in surface pressure
dP        = [Pi(2)-Pi(1) Po(2)-Po(1)];  %psi    change in packer pressure


% Temperature
dT        = -20;                        %F      avg. change in temperature

% Calculate Forces as if the tubing is free to move
Fa        = (Ap-Ao)*Po-(Ap-Ai)*Pi;      %lb     true axial force
Ff        = Ap*(Po-Pi);                 %lb     effective axial force

% Calculate length change associated with Ff
dLf       = Lp/(E*As).*Ff(2)-rc^2/(8*E*I*w(2)).*Ff(2).^2; %in

disp(['The length change related to Ff is ', num2str(dLf), ' in'])

% Critical Buckling Limit (Paslay Dawson)
Fcr = sqrt((4*E*I.*w(2))./rc);
```

Length Changes for packers permitting free motion

```
% All length changes are in inches

% The first length change is deformation due to the true axial force acting
% on the bottom of the tubing. Hooke's law is used:
dL1        = Lp/(E*As)*((Ap-Ao)*dP(2)-(Ap-Ai)*dP(1));

% The second length change occurs due to helical buckling. If the change in
% outer pressure is higher than the change in inner pressure, there will be
% no helical buckling (Lubinski et. al (1962)), hence:

if dP(2)>dP(1)
    % No helical buckling
    dL2    = 0;
else
    % Helical buckling. Calculate length change with a non-linear equation.
    dL2    = -rc^2*Ap^2*(dP(2)-dP(1)).^2/(8*E*I*w(2));
    % Sinusoidal buckling length change by Mitchell:
    % Ff(2) = -Ff(2); % Change signs for Mitchells equation
    %dL2 = -(rc)^2/(4*E*I*w(2))*(Ff(2)-Fcr)*(0.3771*Ff(2)-0.3668*Fcr);
    % Ff(2) = -Ff(2); % Change back for the remaining model
end

% Calculate length change due to radial pressure due to ballooning
% and fluid flow
delta      = 0; % Pressure drop per unit length
dL3        = -(poisson/E)* ...
             ((drhot-R^2*drhoa-(1+2*poisson)/(2*poisson)*delta)*Lp^2/(R^2-1))...
             -(2*poisson/E)*((dp(1)-R^2*dp(2))*Lp/(R^2-1));

% The fourth length change occurs due to temperature change, also known as
% thermal expansion or thermal contraction.
dL4        = Lp*Ct*dT;

% Total length change is then:
dL         = dL1+dL2+dL3+dL4;
```

```
disp(['If the tubing is free to move, the total length change is ', ...
    num2str(dL),' in'])

% Neutral stability point if the tubing is free to move
nfree       = (Ff./w(2))/12; %ft

disp(['If the tubing is free to move, the neutral stability point is ', ...
    num2str(nfree),' ft from the bottom'])
```