

Flow Assurance

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1 Exercise 1

a

LEGG TIL BILDE A PRESSURE PROFILE, BRUKES SOM REFERANSE

b

According to my calculations it seems that the pressuredrop will fall beneath 50 bars after 22 years. At this time it will be necessary to install pressure support

c

The fact that the contribution of liquid is neglected in this multiphase flow is due to a high Gas Oil Ratio (GOR), larger than 40000. In other words gas is dominating in the flow. The main uncertainties of this approximation is the fact that in multiphase flow the fluids contribute more to a pressuredrop than gas(Source page 22s). Because of higher denicity So we might get a lower pressuredrop in the calculations compared to the reality. REWRITE

d

f

Choosing subsea compression auxiliary systems are necessary to protect the equipment and maintain an efficient productionrate.

- Slugging is a threat to the compressor and its interior. Installing an inlet separator prior to the compressor ensures that the compressor only handles clear phases, and not any solids.
- Redusing liquid droplets in the compressor suction is essential to preserve the compressor. This is often called liquid carry over, and can be opposed by using a scrubber which is a system designed to remove these liquid droplets from the gas stream. The reason these liquid droplets pose a risk is at the present liquids such as water and in some sence oil is incompressible. To much incompressible vapor will damage the compressor piston as it strikes, and can overtime give extensive damage to the compressor
- Sediments pose a risk aswell which will damage the compressor parts if they are not taken out of the gas stream. To help out reduce these sediments, chemicals can be added further down the stream to decompose the sediments before they reach the compressor inlet.

1.1 g

Choosing a topside or a subsea compression presents different development impacts.

Project execution Firstly looking at production point of view a subsea solution is more efficient to produce. A topside compressor demands a platform where it can be operated, and personell to man the platform. A subsea solution demands neither, resulting in a lot of cost savings.

Aker solutions have also calculated a reduced CO₂ emission of 60% due to the fact that the requirement of a platform is no longer essential.

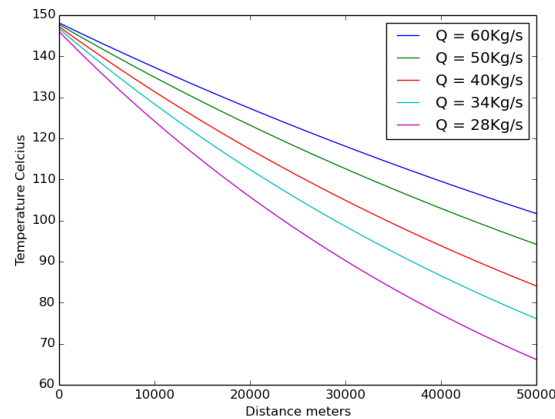
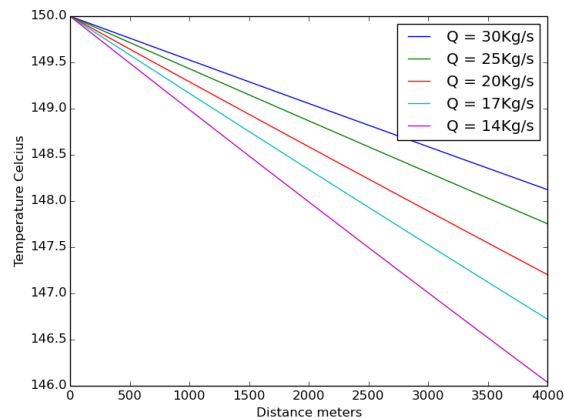
Operation Even though both solutions are made to operate for long periods of time, incidents happen. A compressor located on a platform is easier and more cost-efficient to maintain in operation, while a subseacomponent needed to be changed is very expensive. On the other hand a subsea solution is not exposed to harsh weather and ice found accordingly in tropic and arctic areas, while a rig operation can be delayed by these factors due to equipment and personnel safety. Production over time will reduce the wellhead pressure, resulting in decreased flowrate in the pipes to the production site. Using a compressor subsea will increase production rate by reducing the backpressure at the well as reservoir pressure is reduced over time. The pipes from the well often travel several thousand meters before they reach a topside compressor, and therefore this solution cannot give such an instant effect on the reservoir as a subsea solution.

Exercise 2

In this section we will look at the following flow assurance issues

- Slugs
- Hydrates
- Vibration

a



b

From our lecture notes we know the following conditions are required to form hydrates

- High pressure: typically above 10-20 bar at ambient temperature
- Low temperatures: typically below 20-25 °C Looking at our temperature profile for the pipeline from the well to shore, the temperature will eventually drop beneath this critical of 20 °C due to the long time of low sea temperature exposure.

c

From our pressure profile for each year and corresponding temperature profile, we will unfortunately fall below the Wax appearance temperature (WAT) presented in Figure 4 in the exercises. Especially critical around 10 years, our pressure will be around 220 bar which has a peak on the WAT chart. This means that our gas flow will for a longer time be exposed to critical temperatures below WAT, resulting in a higher risk of wax deposits in the pipe. This will occur in the pipeline from the wellhead to shore. Regular pigging of the pipe may contribute to keep the risk of wax plugs low. Other measures can be used to manipulate WAT in gas flow, such as separation at different temperatures.

Exercise 3

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As stated in the lecture notes hydrate management philosophy is field specific. From field to field different retarding factors influence the theoretical hydrate equilibrium conditions, but the main goal for all fields is to stay outside the hydrate formation envelope calculated by these factors. One must consider how to handle hydrates in normal operation as well as during and under the recovery of system shutdowns. Hydrates are formed when light hydrocarbon molecules and water are present under certain pressure and temperature conditions. Our strategy must include active measures to counter these conditions to happen in our system. Our system operates with a high GOR, we can use control measures such as

- **Water removal**
Liquid water is an essential part of hydrate formations to occur. By dehydrating the gas flow to a certain water dew-point we can prevent the creation of hydrate formations for the specific system.
- **Chemical injection** Chemical injection can be used to alter the conditions for hydrates forming as well as their structure.
Thermodynamic inhibitors are used to lower the hydrate equilibrium temperature which formations can be formed, resulting in that the gas flow can handle lower temperatures without hydrates being formed.
Low-concentration inhibitors are used to alter the hydrate structure delaying the hydrate or making them unable to plug the line.

Exercise 4

Exercise 5

During X-mas tree design we have to be aware of both internal and external flow, which can force mechanical vibrations from pressure oscillations. This becomes dangerous if the oscillations hit one of the system eigenfrequencies. External flow from local current can produce these oscillations around a pipe segment due to vortices created by the geometry.

For flow-induced vibrations in the pipeline, resonance cannot be avoided. Due to the fact that flow excitation is able to reach a wide range of frequencies, we cannot avoid resonance by trying to change the eigenfrequencies of our tree. Therefore weakspots have to be reinforced so that the estimated time before a failure occurs is longer than the production lifetime. This can be simulated using Computational Fluid Dynamics, and analysis in structural mechanics.

It is worth to mention that acoustic pulsation in dead legs can cause pressure oscillations if the vortex shedding from these dead legs is the same as one of the acoustic frequencies of the dead leg. As I interpret the question this is not a flow induced vibration, but is worth mentioned.

Subsea design and development

Different factors have influence of the development solution. First and foremost we have to evaluate the reservoir.

- The length of the well need to reach the reservoir may be several thousand meters, which overtime require pumps ,compressors and waterinjection to maintain pressure for production.
- A larger reservoir requires more productiontrees if we want to exploit the reservoir for maximum production.
- The amount of production trees lay basis for the amount of powersupply needed.

These factors imply that for each productiontree we need supportunits to help maintain production. One approach might be to design a production solution based on sections. Firstly all producing christmastrees run their production into a main christmas tree for gas and oil separation. Close to the wellheads waterinjection templates are installed to help maintain the pressure in the reservoir. From the main christmas tree gas and oil are separated, so the gas can be compressed before they are sent in the export pipe. A main controlbase are built to distribute electrical power and control the whole subsea section.

Factors such as water depth and distance to the receiving end of the export pipeline, will influence the amount of pumps, compressors and electrical power to power the transport of hydrocarbons from the subsea factory. This will result in more subsea components needed to be build.

Due to norwegian law, each subsea unit must be protected by a welded roof to protect the units from fishing operations and subsea debris.

One might also consider to lay all pipes and wires needed for production on the seabed, to make ROV operations safe and to avoid the chance of damages on the system while operating the ROV.

Reservoir parameters

Depth of reservoir (length and height of well)

Water depth (height of riser)

Gas oil ratio (GOR) (average density of fluid)

Water production (average density of fluid)

Step out length (distance from well to platform)

Diameter of wellbore

Diameter of pipeline

Separator pressure

Exercise 6

The main function of a subsea Christmas tree is to control the flow of hydrocarbons from the well and to the production recipient. This means by controlling production valves in the pipesystem, the flow of hydrocarbons can be altered and the christmas tree itself acts as a safety barrier.

The structure also acts as a base of intervention when it comes to flow properties by chemical injections, and as a control unit forwarding electrical signals controlling gauges and pumps. TALK ABOUT HOW THEY ARE INCLUDED IN THE DESIGN, SEPARATORS ETC