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Abstract

Oil and gas exploration on the Norwegian Continental Shelf has been going on since the 1960. Many smaller oil fields have been found and at that stage they have not been developed, because alone they have not been economically recoverable with the technology of that day. The Gullfaks field started to produce in 1986 and when the subsea concept was developed, the nearby oilfield Gullfaks South was developed as a subsea solution in 1998, tied-in to the Gullfaks A platform. Low production rates and newer 4-D seismic surveys of the Gullfaks South field showed that the recoverable oil from this field was only 8%. This was the key driver for the new development, the GSO, Gullfaks South Oil. The GSO project shall increase the recovery rate by developing the field with 2 new subsea templates that includes four production wells and two gas injection wells.

The Gullfaks Oil field is already developed with six templates including flowlines that have been producing since 1998. Some of the existing infrastructure shall be re-used due to the existing templates are at their end of production lifetime. Lack of spare J-tubes for new risers on the Gullfaks A supports the decision of re-using existing infrastructure. The production template, the O-template, shall be tied-in to existing flowlines. By re-using these flowlines the cost of the development will be reduced, but limitations will be given due to fixed diameters on the flowlines. The O-template shall have one 8” and one 6” flowline, these are within the design criteria of material stresses based on the reservoir properties and ambient environmental properties. Arrival pressures on the platform, from the template are within the limitations of the process pressure at 56 bars for the 8” throughout the whole production lifetime. The 6” shall co-produce with other wells, this is only analysed to this point where they start to co-produce. The injection template, the P-template will have an extended flowline from another injection template, this will provide necessary reservoir stimulation for the GSO.

The production flowlines, the 6” and 8” are analysed for flow assurance challenges. Flow assurance is a very important design requirement for subsea flowlines. It is important to understand how and why they occur to be able to mitigate them. It is essential to keep good flow assurance for a subsea development, and necessary to understand how to both avoid them and to get out off flow assurance challenges in a safe matter. The challenges found are manageable with the chosen measures. The analyses are done with the basis in the production profile and the ambient surroundings. The 6” and 8” flowlines are not redundant, but a supplement to each other during the whole production lifetime. The 6” is suitable in the beginning and end of the production life, the 8” is the best option in the middle part of the production lifetime.

The GSO development is a sensible development to increase the recovery rate at the Gullfaks South oil field.

Acknowledgement

This thesis marks the end of my Masters degree in Offshore Technology, Marine- and Subsea Technology at the University of Stavanger. This has been some great years, it has been a work comprehensive period, but I have had a great personal development as well.

I would like to thank the whole Gullfaks organisation in Statoil ASA for facilitating for me to take my Masters degree beside my work at Gullfaks. The organisation has also provided me with information needed during the education and for writing my thesis. I will especially thank two of my nearest leaders, Mr Geir Harald Nilsen and Mr Norvald Tykhelle for making this possible.

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Ole Martin Holmefjord

Bergen 09.06.2015

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Abbreviations

C_1	Methane
C_2	Ethane
DEH	Direct Electrical Heating
DNV-GL	Det Norske Veritas Germanischer Lloyd
FPSO	Floating Production and Storage Unit
GOR	Gas Oil Ratio
GSO	Gullfaks South Oil
HC	Hydro Carbons
HSE	Health, Safety and Environment
HISC	Hydrogen Induced Stress Cracking
HP	High Pressure
ID	Inner Diameter
ISO	International Standardisation Organisation
LP	Low pressure
MSm^3	Million Standard Cubic Meters
NTT	No Touch Time
OD	Outer Diameter
Pi	Internal Pressure
Po	Outer Ambient Pressure
SMYS	Specified Minimum Yield Strength
SPS	Subsea Production System
TLP	Tension Legged Platform
UTIS	Universal Tie-In System
WAT	Wax Appearance Temperature
3-D	Three Dimensional
4-D	Four Dimensional

1 Introduction

The GSO development shall increase the oil recovery rate on the Gullfaks South field by further develop the field with two new subsea template. These two new templates shall be tied-in to existing flowlines that are tied-in to Gullfaks A.

1.1 Introduction

The Norwegian oil and gas adventure has been a great benefit for Norway and its residents. Some parts of the oil and gas industry are commonly known, other parts may be more unfamiliar for the majority of the people. The oil and gas age that I have been born into has been an age of technology and economical growth, and have been for a great benefit for me. The oil and gas recovery has been fascinating me for a very long time. And as I started to work as a process technician at an age of 18 on an oil production platform, the hunger of understanding more has only grown. That resulted in that I started at the “subsea technology” undergraduate program at Bergen University College. After completing my Bachelors degree I continued for the Master program “Marine- and subsea technology” at University of Stavanger.

The Norwegian continental shelf is explored throughout many years of exploration and production. Many smaller oil fields have been found and at that stage they have not been developed, because alone they have not been economically recoverable with the technology of that day. Large fields like Johan Sverdrup is still found, but that is more rarely. Today it is more normal to find smaller oil fields that in it self is not economical recoverable, but as a tie-in to an already existing installation they can be recoverable. Since production facilities like separation, oil transport, gas transport and water treatment systems already are in place for a nearby platform on larger fields.

Oilfields that already have been developed, and been producing for a while, will experience a change in oil production over time. This is due to the reservoir is being drained, pressure is changing and the predicted HC (hydrocarbons) path could be a bit different than first expected. Also if the reservoir has been stimulated with injection of either gas or water, the reservoir can change and HC being pushed away from the production well after a while. This is due to among faults that are not seen on first seismic exploration.

In this thesis I will highlight the driving factors and the design requirements for a concept selection of a field development. Further I will go deeper into flowline design, the factors that decide the dimensions for a pipeline. Transport of reservoir fluids can be a challenge, and the flow assurance is a key design requirement of every field development. The flow assurance aspects will be discussed and measures to keep good flow assurance will be presented. These headlines will be analysed with the new field development, the Gullfaks South Oil as a basis for case analyse.

1.2 Objective

The Gullfaks South reservoir is an oilfield currently developed with six subsea templates that are tied back to the two platforms Gullfaks A and Gullfaks C. Today a project is on-going for a further and more complete development of the oilfield. The development is called the GSO (Gullfaks South Oil) project and shall be installed with two new templates, one production template, and one injection template for reservoir stimulation. In this thesis I will:

- Understand the driving factors for the concept selections, the limitations and possibilities of using existing installations for a field development. I will describe and explain the background of the choices made for the GSO development.

- Verify the suitability of using existing subsea equipment for the new GSO development with respect to flowline dimensioning and pipeline strength with the GSO reservoir properties as a basis.

- Describe the flow assurance challenges in general and analyse the flow assurance challenges of the field specifics of the GSO development. With this as a basis I will check the suitability of the different flowlines with respect to the GSO production profile during it whole production lifetime.

1.3 Method

The Gullfaks South Oil design basis will be used as a support to get relevant information of the field. Physics coherence for calculating and analysing the suitability of the chosen solutions is the essence of this thesis. There are a lot of standards regarding the different design methods, one single standard will not be used for analysing but a more physics inspired approach to the problem solving will be used.

The existing infrastructure nearby the GSO development will be decisive for developing a field like this. Reservoir size, content, optimal drainage strategy is key drivers for how to develop the field, which concept that is suitable.

The Gullfaks field was first developed in 1986 and has continuous up to this date been further developed for maximum oil recovery. Existing structure on the field consist of three con-deep platforms and in total 12 subsea satellite templates tied-in to the platforms. The GSO development shall increase the oil recovery rate on the Gullfaks South field by further develop the field with two new subsea template. These two new templates shall be tied-in to existing flowlines that are tied-in to Gullfaks A.

The objective of this thesis will be solved by:

- Check nearby existing infrastructure for development options.
- The GSO reservoir properties are decisive for field development selection, by these the production profile of the field will be estimated. This production profile and the drainage strategy will be analysed for the GSO concept selection.
- Verify the re-use of the existing flowlines with respect to hoop- and longitudinal stress. Verify that limitations for tying-in to the Gullfaks A platform will not compromise the development.
- Analyse the flow assurance challenges through the flowlines for the GSO subsea development, the challenges will be presented with measures. Find the limitations for the different flowlines throughout the whole production life.

2 Field development

Developing an oil and gas field demands a good understanding of several key drivers. The GSO development is a field nearby several existing platforms and infrastructure. This infrastructure can be useful and decisive for the concept choice of the GSO. The distance from the existing infrastructure to the reservoir, and the reservoir content is decisive if the existing infrastructure can be used for developing the GSO. The reservoir size and complexity will give a recommended estimate of needed drainage points. The estimate and recommended number of wells can exclude some concept alternatives. Reservoir properties will also give information of needed reservoir stimulation with respect to injection wells. A production profile of the reservoir will give information of the well stream, the composed fluid and the quantity of the fluids can be dimensioning for selected concept. This chapter will highlight possible development solutions, the key drivers for concept selection and the chosen concept for the GSO development. Opportunities and limitations of the selected concept will be governing for the development. The selected concept will be explained, and this concept together with the production profile will be the basis for the further chapter of this thesis.

2.1 Background

The field was discovered in 1978 and developed in 1998 as a subsea solution with tie-in to both Gullfaks A and Gullfaks C. The field is in block 34/10 with the production licence PL050, ownership is Statoil with 51%, Petoro with 30% and OMV with 19% [1].

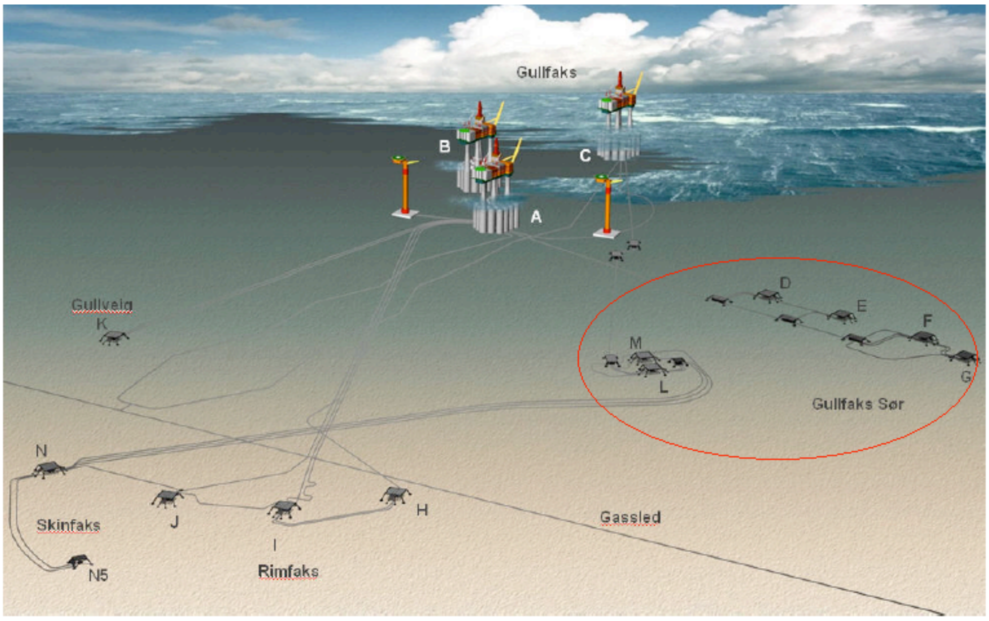

Figure 2.1 The existing Gullfaks South oil field tied back to Gullfaks A and C[2].

The Gullfaks South oilfield is developed with six templates. The D-, E-, F-, and G-template are tied-in to the Gullfaks A platform, and template L and M are tied-in to Gullfaks C showing in figure 2.1. The E-template is a gas injection template providing reservoir pressure for the reservoir, the remaining five templates are producers.

The surveys prior to the development in 1998 described the goals for the development to be able to produce the reservoir reserves at 12,6 MSm^3 from a total at 29,7 MSm^3, giving a recovery rate at 42%.

After producing the field for 10 years, newer exploration and reservoir analysis is estimating new total reserves are at 41,6 MSm^3. The historical production from 1998 to 2008 is only 3,3 MSm^3, which gives a recovery rate at only 8%. The reservoir was more complex to produce than first anticipated. This was the key driver to the new GSO (Gullfaks South Oil) development, to increase the recovery rate and production of the Gullfaks South oilfield reservoir. The existing templates F and G are estimated to produce +2,8 MSm^3 for the remaining production life. The GSO development shall increase the recovery rate and it consists of among two new template solutions, other equipment will be discussed later. One template will be a four-slot production template, the other template will be four-slot injection and production template. Where it will at first be drilled 2 injection wells, leaving the optional two slots for potential new wells on the template for a later time. The production template will be named O-template and the other with injection wells will be called P-template showing on figure 2.2. With the GSO project and the two new templates with four production wells and two new injection wells for reservoir stimulation, it is estimated to produce +6,9 MSm^3. This gives a total production of 3,3+2,8+6,9=13 MSm^3, and a recovery rate at 31% that is significant larger than todays 8%.[3]

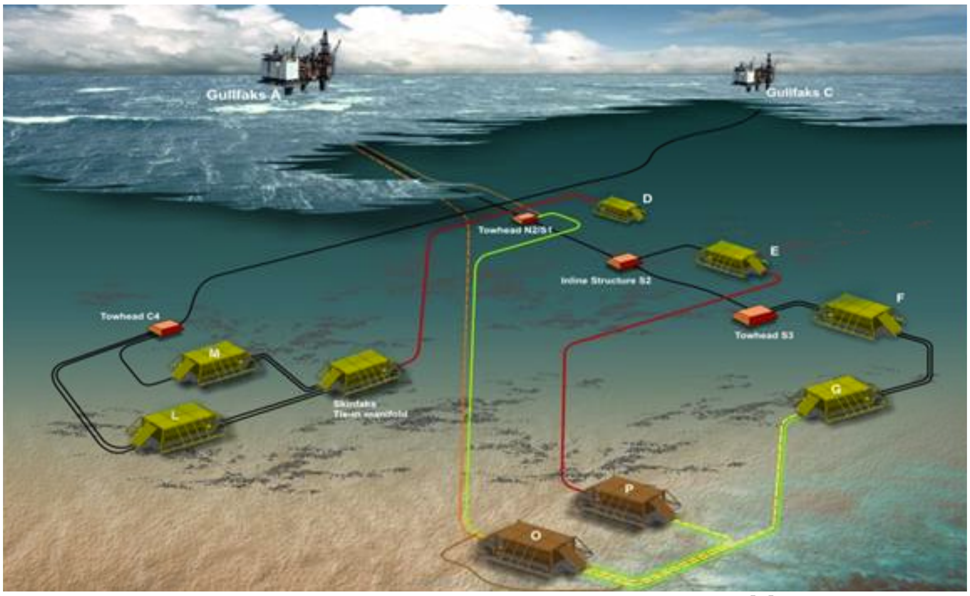

Figure 2.2 The GSO field with the two new templates O and P [3].

To increase the recovery rate for the Gullfaks South field, the GSO project will be developed and the field will consist of:

- Template O and P are new templates included in the GSO development.
- O shall be tied-in to towhead N2/S1 with an 8" flowline, in addition will template O be tied-in to G. P shall be tied-in to template E for gas injection.
- Template D, E, F and G are existing templates tied-in to Gullfaks A.
- Template L and M are existing templates tied-in to Gullfaks C.
- Template D shall be re-routed to Gullfaks C.

2.2 Existing infrastructure

The GSO reservoir is located at a water depth of 134m on the Gullfaks field where there are three nearby platforms already developed and producing, the Gullfaks A, B, and C. The A platform is located on a water depth of 134 m and C platform on a water depth at 210 m, these are two stand-alone platform with some technical differences. The B platform is a simpler platform that only treats the well streams lightly before it is transported to either the A or C platform for further treatment. The Gullfaks South field is today already partly developed by subsea solution templates, there are in total six templates where five of them are producers and one is an injector. These templates are tied-back to the two stand-alone platforms Gullfaks A and C with flowlines and control systems. The distance from the GSO reservoir is approximately 8-12 km away from the nearest platform Gullfaks A, and approximately 20-23 km away from Gullfaks C.

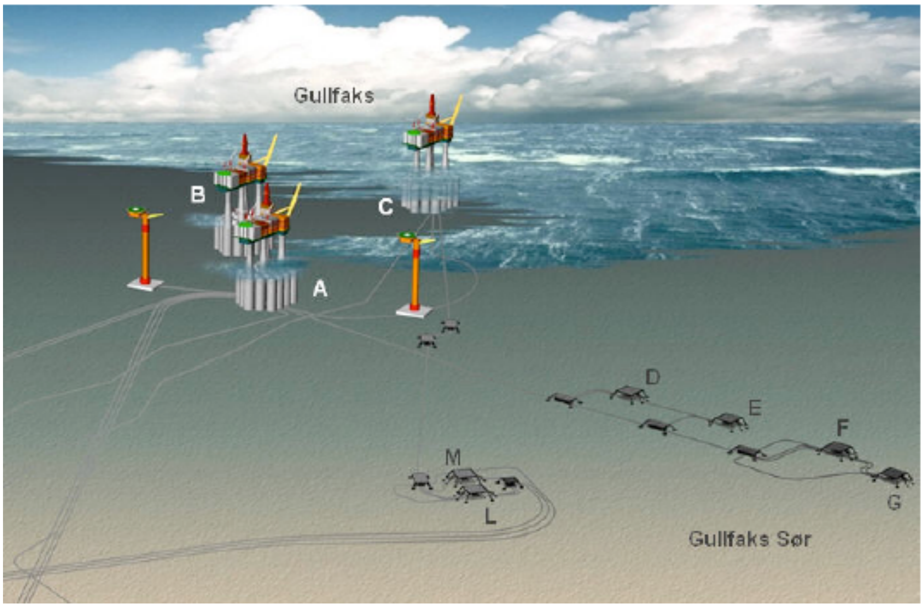

Figure 2.3 Existing structure on Gullfaks South

2.3 GSO reservoir

The already developed Gullfaks South reservoir have been producing since 1998, and it has been done several seismic surveys prior to this development and throughout the production life of the reservoir after developed. To explore the soil layers underground, 3-D seismic has been and is the standard to get geological information on the Norwegian

Continental Shelf. After the first seismic maps are interpreted it is possible to start exploration drilling, and if positive drill results and well testing the reservoir will be developed if economical recoverable. Producing a reservoir over time will change the initial conditions, the fluids in the reservoir may not stream as anticipated and fault may come clearer after a while when producing. 4-D seismic is comparing the same geological map over time, the fourth dimension time.

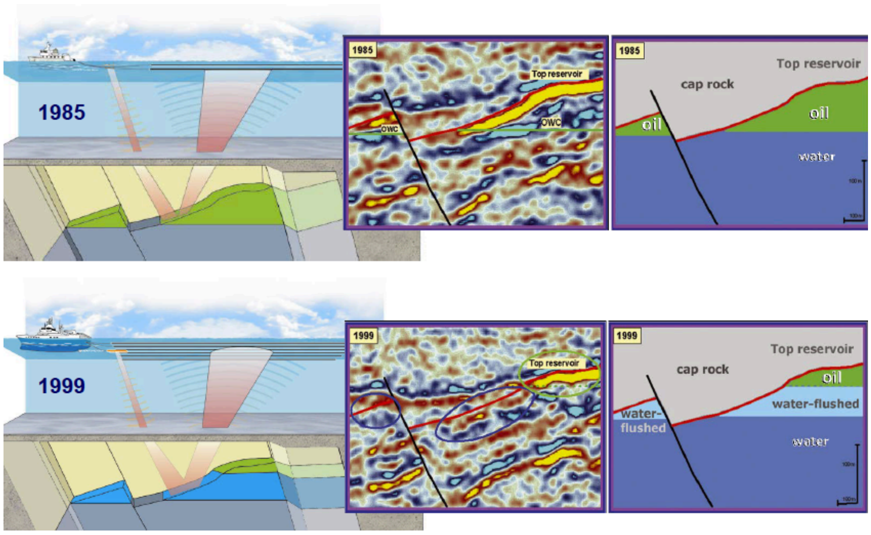

Figure 2.4. 4-D seismic compares the same area over a time period [4].

Comparing the same area over time while producing gives a clearer picture of how the reservoir fluids are behaving and faults may be clearer, shown in figure 2.4. Doing this will give a more certain development of the field.

The recovered oil on the Gullfaks South field from 1998 – 2008 was only 8%, which is the key driver to develop this field further. The low production rates showed that the first interpretation done prior to the development in 1998 wasn`t correct. Further seismic surveys together with earlier surveys made the basis for 4-D seismic, the conclusion of this 4-D mapping was that the reservoir was much more complex than it was possible to see in the beginning. The traps in the reservoir became clearer, the communication between the different segments was worse than anticipated. The last seismic surveys showed that the southernmost part of the Gullfaks South reservoir did not get drain at all. The reservoir was not changed, but the on-going production and newer surveys has provided a better understanding of the complexity of the reservoir. This realization underlays for more drain points, wells of the Gullfaks South field. [5]

2.3.1 Recoverable oil and PVT correlation

The newest estimate of the GSO reservoir estimates total oil and gas reserves of 41,6 MSm^3 HC. The reservoir reserves are calculated after reservoir conditions are mapped from the seismic survey, drill samples and well testing of the actual reservoir.

The desired oil and gas that shall be produced are trapped inside rocks and will be recovered by letting the reservoir fluids flow out of these rocks. How much fluid these rocks contain and how easy they will flow determines the recoverable oil and the need for reservoir stimulation. Oil saturation is a description of the pressure, temperature and volume of the reservoir. For which properties oil will change phase over to gas. The saturation can be stimulated to keep the oil in liquid phase with e.g. gas injection.

An oil reservoir is a closed segment with a constant temperature and pressure until it is started to produce from it. A producing well`s fluid is driven through the tubing, wellhead and flowline to its process facility from the reservoir pressure, if seen away from potential artificial lift. Since the reservoir is a constant volume the pressure will drop when loosing reservoir content. When a fluid is exposed for high pressure, this fluid will become liquid until it is saturated. Reducing this pressure will lead to the liquid to change phase over to gas at a certain pressure depending on the content of the fluid, this point is called the bubble point. For a gas changing phase to liquid it is called the dew point. These points are also depended on the temperature. For a known fluid in a closed segment it is possible to create a pressure-temperature diagram showing the bubble point line and dew point line. Example of a pressure-temperature diagram is shown in figure 2.5. [6: 123]

An under-saturated oil reservoir is a reservoir where the oil phase will bubble over to gas when the pressure is declining due to production at a certain point. This is called a bubble point reservoir and will loose its reservoir pressure relatively quickly due to liquid. A saturated reservoir will behave some different from the under-saturated, since it is saturated it is not that sensitive to pressure change as an under-saturated is. Otherwise the principles for both types of reservoirs are the same.

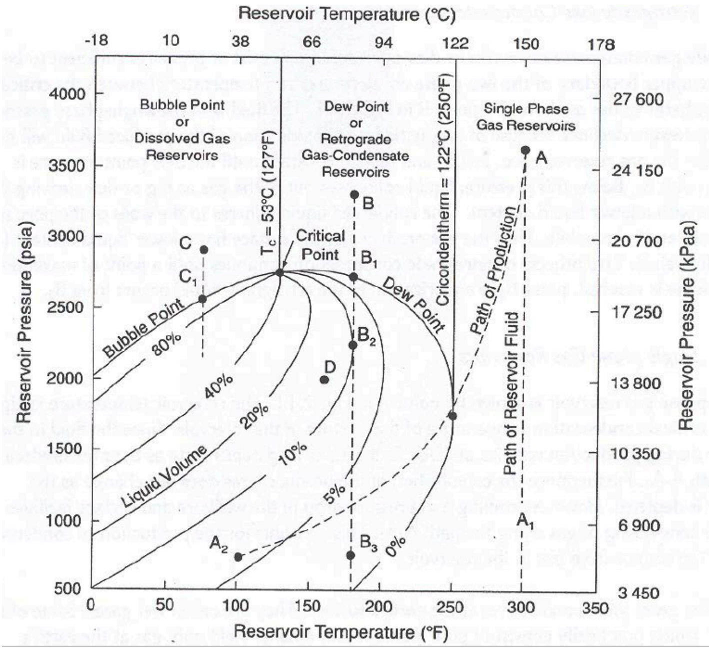

Figure 2.5 Pressure-temperature diagram.[7]

Gas injection is important to have the pressure drive mechanism for the well stream and for pushing the HC to the drainage points. But as important is to keep the hydrocarbons in the oil/liquid phase, by injecting gas into a saturated reservoir it is avoided that the pressure is declining.

The GSO development is a reservoir that could be placed all the way in the left of figure 2.5. This has a bobble point in the gas-oil phase at 385 bars, which is essential to maintain to avoid phase changing while producing. Oil is more economical to recover and produce than gas, the longer it is possible to keep the reservoir in liquid phase the more profitable the project will be. This is something the reservoir-engineers are watching closely during production by measuring and monitoring the reservoir pressure and temperature. The GSO reservoir is desired with gas injection to keep the reservoir into liquid phase as long as possible and reasonable. In addition will the gas injection keep high enough pressure in the reservoir for the liquid to be “pushed” out. If only the depletion method of the reservoir would be used, most of the oil would have been lost in the reservoir due to too low pressure.

The reservoir engineers recommend four new production wells for best possible drainage, and two gas injection wells for reservoir stimulation on the GSO development.

2.4 Production profile

Due to many seismic surveys of the field and in addition the Gullfaks South field has been in production for many years, the estimated production rates are quite certain. Still it is not possible to be completely certain, Statoil`s reservoir engineers have estimated the production rates of the four new production wells to be as in the four tables attached in the appendix. The Statoil reservoir engineers have been using the reservoir simulation program Eclipse 100 for estimating these production rates. These production rates are put together as one total production rate table for the whole GSO development seeing in table 2.1.

The production rates are given in Standard cubic meters (Sm^3) that are the volumetric standard unit for measuring oil and gas volumes, this standard is given from the ISO, International Standardization Organization. The reason for standard conditions is that there will be different pressures in the different section in the production and sales stages. Liquid is incompressible while gas is compressible. 1 Standard cubic meter (Sm^3) is at the following conditions:

- Pressure = 101,325 kPa.
- Temperature 15°C.

Table 2.1 Production profile

GSO production profile				
Production year	Oil prod per day in Sm^3	Gas prod per day in Sm^3	Water prod per day in Sm^3	GOR
1	166	56381	1	340
2	1195	998008	66	1898
3	2195	2827669	518	5657
4	1926	3128773	358	8883
5	1874	4056768	348	12784
6	1636	4133826	253	15351
7	1401	4183895	183	19573
8	1226	4207934	143	24303
9	1064	4223556	124	27646
10	943	4233865	110	32313
11	834	4239055	107	38304
12	773	4238349	98	42224
13	721	4230929	90	35463
14	683	4187580	91	49361
15	403	2250008	69	36239
16	344	2323806	70	37701
17	244	1609232	66	37541
18	122	1077900	47	39393
19	63	688850	23	48248

The four producing wells are put together as one total production profile of oil, water and gas. The production profile is based on the estimates of the expected production of each well from year 1-19 for the GSO development.

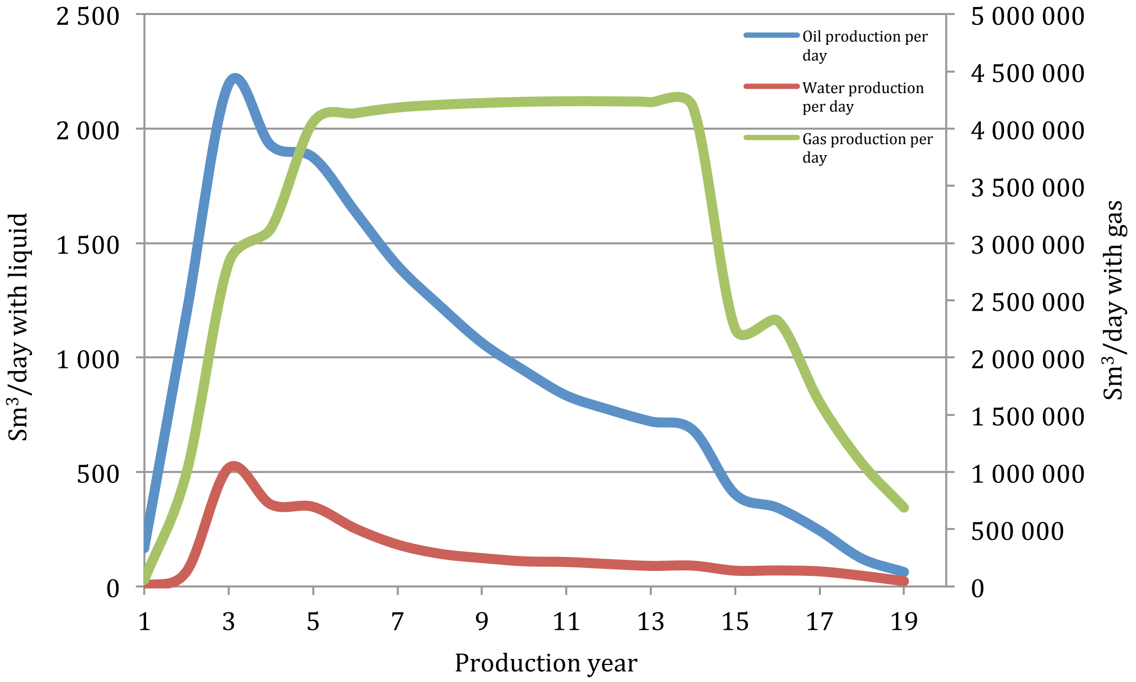

Figure 2.6 Production profile

This production profile and rates showing in figure 2.6 is giving the basis of further design of associated equipment, well design, flowline size and normally the process facilities. It is also worth noticing that both oil and water production is peaking at the same time around year three of production. The liquid peak together with the current gas production can dimension or limiting the choice for equipment and concept choice for the development. The 3-phase flow can also be a challenge for the chosen concept solution.

2.5 Concept selection

Oil and gas exploration and recovery has been going on since 1960-1970 on the Norwegian continental shelf and therefor there is a lot of knowledge and experience with different concept solutions. Even though with this experience it is not possible to have a complete standardized development for every field development. Reservoir size, complexity and content will vary. Well layout and design, water depth, environmental conditions, productions rates and volumes, reservoir chemistry, nearest production and transport facilities are some aspects that will narrow down and determine parts of the concept solution in an early phase.

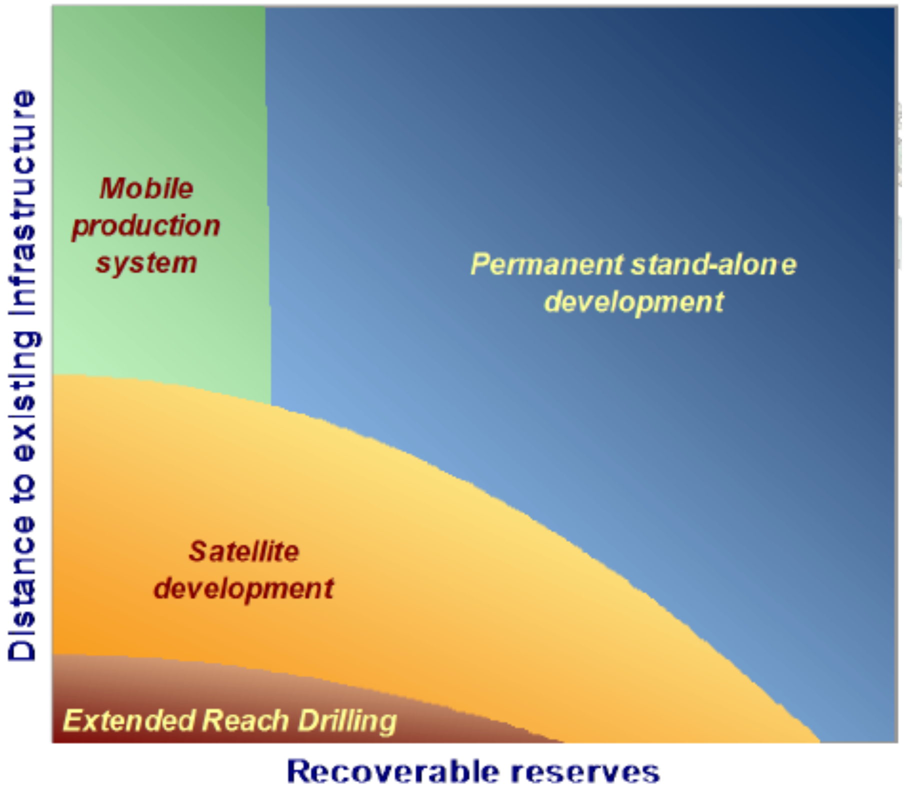

Figure 2.7 Illustration between recoverable reserves and distance to existing infrastructure. [8]

Figure 2.7 shows a quite simplified ratio between recoverable resources and distance to existing infrastructure and shows which type of concept that is applicable in the different situations and ratios. Even though this is very simplified it can give a good indication of what sort of concept that is applicable.

The distance in figure 2.7 must be seen as an indicator because it is actually the well stream and reservoir chemistry that decides if a reservoir is remote or not. It is not possible to have a general map that describes remoteness, but again it is an indicator. Well stream and reservoir chemistry can be described in the term "flow assurance". Flow assurance is a wide term, but in general it describes how the well stream or any other fluids are flowing, this will be further described in the flow assurance chapter. Reservoirs consist mainly of HC- liquid and gases, other gases like H_2S and CO_2, water and solids. Producing oil and gas together with water will limit the distance it can flow before the flow assurance will be challenged, only 10km can be max distance of this type of well stream. Therefor it is necessary to have a production facility that can separate and treat the well stream for further transport to costumer and marked. Other well streams that contains mostly natural gas, methane, and very little amount of water can be transported longer distances with out any separation, example the Snøhvit field at Melkøya which is 143km long [9]. There are mainly four different concepts that can be chosen for a field development and are presented in the next sub-chapters.

2.5.1 Stand-alone development

Building a stand-alone platform or semi-stand-alone on the GSO field could be done. The depth of the GSO reservoir is 134m, which implies that a fixed jacket structure would be suitable for the development. A fixed jacket structure allows for dry trees with the benefit of not being remote. Maintenance and interventions on dry trees are easier than subsea trees. Dry trees also demand some sort of a derrick, either a drill derrick or a well intervention tower that the platform should be installed with. The recommended drainage strategy for the GSO reservoir is four production wells and two injection wells for stimulation. A full process facility would be very expensive for this well stream only. But the platform should have a first stage production facility to treat the wells stream before transporting the well fluids to a nearby platform with full process facilities. This is for avoiding flow assurance challenges. The platform needs also injection pipelines from a nearby platform. This means that the development must consist of a jacket structure with simplified process facilities. A drill derrick or intervention tower, relevant utility systems, a living quarter for personnel and pipelines for transporting the well fluids to a nearby platform for further treatment are needed.

2.5.2 Mobile Production system

A mobile production system can be used when the reservoir is outside the economical or technical limit from other installations or shore. Handling the HC production in a safe matter is the first priority in a field development. A mobile production system would demand subsea wells for keeping the integrity and barrier philosophy intact. A mobile production system could for several reasons need to move and the wells are the barrier against the reservoirs, which implies for subsea wells. The water depth of 134 m reduces the numbers of available mobile jack-up platforms. FPSO could be an alternative. These could both be leased, but again four production wells and the need for gas injection would need a gas injection compressor or support from a nearby platform. Normally the recovery ratio will be somewhat lower due to the mobile production system is not tailored suited for the field specifics.

2.5.3 Extended reach drilling

When horizontal drilling was developed to increase oil recovery it also got possible to drill further out from the stand-alone installation where the drill derrick is. Extended reach drilling made it possible to recover more HC from the stand-alone developments with drill derricks. Today it has been drilled horizontal wells at 10km, but this demands a highly upgraded derrick tower and great precision. The Gullfaks A platform is within a range of 8-12 km of the GSO reservoir. The production start should not be started before injection wells are ready to avoid phase-transition in the reservoir. The drill derrick of Gullfaks A was installed together with platform in 1986, and are to be used for all existing wells drilled from this platform, including intervention. Drilling six wells into the GSO reservoir at this distance holds a lot of uncertainties with respect to managing all six wells, time and money.

2.5.4 Satellite development

Smaller fields just outside the technical or economical limit to perform extended reach drilling can be developed by using subsea satellite solution. Satellite solution includes templates and associating equipment, SPS (subsea production system). These subsea satellite concepts will be tied-in to a nearby platform or shore using flowlines. The Gullfaks South field has already been developed with six templates, including gas injectors. A lot of subsea infrastructure is installed nearby the GSO development. Re-using, extend flowlines and tying-in to already installed equipment will reduce the development costs for a subsea selection. Platform capacity for tie-ins must be checked and flow assurance for subsea developments will give design requirements.

2.6 Regulation, standards and guidelines

Either way the chosen concept solution, there are regulations, standards and guidelines that must be followed for producing oil on the Norwegian Continental Shelf. To be able to produce oil and gas it is necessary to be able to manage the well stream fluid. HSE (Health, Safety and Environment) is fundamental to be allowed to produce HC (Hydro Carbons) on the Norwegian Continental Shelf, as well as in the rest of world. The regulations have to be followed by all operators on the Norwegian Continental Shelf and are essential for a field development.

Rules, regulations and guidelines are given from the Norwegian Parliament and throughout whole chain down to company level.

There are four sets of regulations for HSE in Norway`s offshore petroleum sector, the regulations consist mainly of risk- and performance based requirements. The requirements are set by the: Petroleum Safety Authority Norway, Norwegian Environmental Agency, Norwegian Directorate of Health, and the Norwegian Food Safety Authority [9].

The requirements and guidelines that are given by the authorities are governing for all petroleum activity on the Norwegian continental shelf. In addition to these main sets of regulation, standards, guidelines and "recommended practices" are given from Norsk Standard, Norsok, DNV-GL, IMO, API etc. and referred from the governing requirements. These are more detailed and descriptive for each different case. It is the operators and contractors that are responsible to follow these regulation and recommendations, they shall follow the regulations or be able to document that the chosen solution is equal or better than the relevant standard. The authorities, standards and guidelines are the initial starting point for every development on Norwegian shelf. Then the operator or contractor will break the project scope down to detailed work packages and use relevant recognized industry standards and guidelines and further down to company-specific requirements and standards. [10]

Regulations, guidelines and standards are given in the following order:

- The Parliament of Norway
- The Government
- The different offices of ministry
- The Norwegian Petroleum Directorate, Climate and Pollution Agency, The Petroleum Safety Authority,
- Operator or sub-contractor
- Relevant recognised industry standards like ISO, NORSOK, API
- Internal company guidelines

2.7 GSO concept and layout

First some driving factors and design requirements will be given as an overview to understand the chosen solution:

- There are two stand-alone developments in the range of 8 km (Gullfaks A) to 20 km (Gullfaks C) in the area of the GSO development.
- These two stand-alone platforms have already existing subsea development from the nearby field.
- It is a quite complex reservoir that needs four producing wells and two gas injectors for reservoir stimulation for the optimal drainage strategy.
- The reservoir is large with a production profile which goes over 19 years.
- The producing fluid is a 3-phase well stream with oil, gas and water.

The GSO reservoir is not large enough to be a stand-alone development, this demands large economical invests. Since there are existing facilities nearby, these could be used for developing the GSO field. These facilities will give both opportunities and limitation for the development. The reservoir does also need stimulation in the form of gas injection. The producing well stream will be a 3-phase flow, which will have flow assurance challenges and maximum flow distance until it needs treatment.

The Gullfaks South Oil field is approximately 8-12km away from the stand-alone platform Gullfaks A. Gullfaks A is a con-deep platform with all process facilities, oil storage and export, and gas treatment, export and injection systems. Parts of the Gullfaks South field have already been developed with six templates, including HC producers and gas injectors. These are today tied back to both the Gullfaks A and C platforms. On Gullfaks A there has been drilled a well, extremely long extended reach well, Gulltopp at almost 10km [12] into the Gullfaks South reservoir. It is possible to drill this far with the derrick at Gullfaks A, but this one well took almost 2 years alone to drill and became much more expensive than first estimated. In addition the derrick tower became locked up to this well for all this time, meaning other wells planned to be drilled and well interventions that requires a derrick tower was put on hold for that period.

The Gullfaks C platform is quite similar to the A platform, a main difference is that it does not have the gas injection system that the A has, which the GSO reservoir demands. This means that the reservoir stimulation wells must come from Gullfaks A. The distance from GSO to the C platform is also longer, approximately 20 km. This distance excludes extended reach drilling from the C platform. The distance will also create larger flow assurance challenges than if routing the GSO towards Gullfaks A.

The already installed and developed subsea templates on the field have been producing since 1998, some of these templates are at their end of the production lifetime. The templates are developed with flowlines, umbilicals and SPS. If some of the templates that already are installed is at their end of production time or producing so little that it could be re-routed to other installation or should be de-commissioned. Then some equipment could be re-used. By re-using some of the equipment, the GSO development would be less expensive. It is possible to tie-in on the existing flowlines if they are suitable and extend the umbilicals further to the new development. It would be both sensible to re-use already installed equipment, and cheaper since the length would be reduced for both the flowlines and umbilicals. By doing this there will be some limitations for the development. The existing flowlines that could be tied-in in to and re-used will be with a fixed and limited diameter, this should be checked for the GSO development.

A subsea development that shall be tied-in to a platform, need a riser to get the well stream safely on-board for processing. On stand-alone platforms there are several flowlines and pipelines that shall enter or leave the platform, this can be import of oil for storage or/and oil export, gas export etc. For a fixed platform, pre-installed J-tubes are used to letting the flowline or pipeline enter the platform on a safe matter illustrated in figure 2.8.

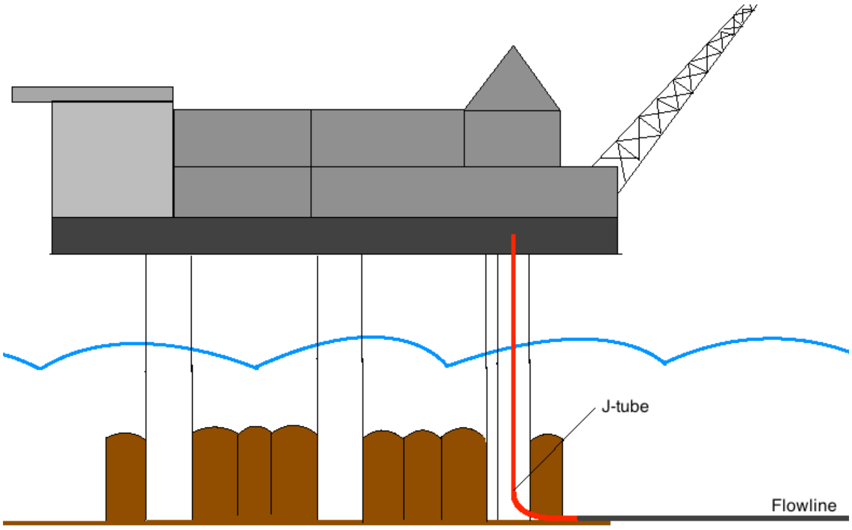

Figure 2.8 J-tubes are used on fixed platforms for tie-ins

The Gullfaks A platform has been producing since 1986 and is utilized and developed during this period, meaning there are many gas and oil export and import pipelines installed on the platform. In addition flowlines for the existing subsea developments that is tied-in to the platform has their own separate J-tubes. Today it is getting short on available free J-tubes for new tie-ins on Gullfaks A. This is another argument for re-using existing subsea equipment.

Drilling the Gulltopp well from Gullfaks A, a lot of experience and information of extended reach drilling was gained. The uncertainties in drilling such long wells became too large for the numbers of wells and complexity of the reservoir. The extended reach well concept is not suitable for this development.

The existing subsea development of the Gullfaks South field consists of total six templates tied-back to both Gullfaks A and C. Figure 2.9 shows the layout of the existing subsea templates and flowlines. Template L and M are tied-in to Gullfaks C with a total of three flowlines. Template D, E, F and G are tied-in to Gullfaks A in a heated and protected bundle with a total of four flowlines. The E-template is a gas injection template containing an 8” flowline. F and G are sharing two 6” flowlines, and D-template has an 8” flowline.

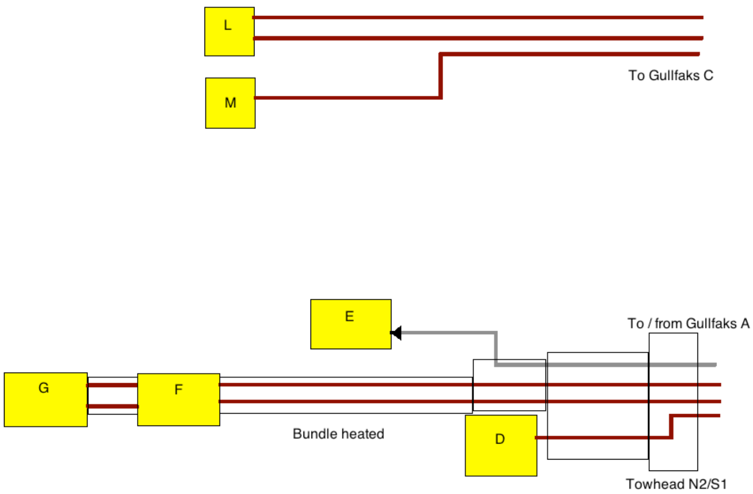

Figure 2.9 Existing layout

2.7.1 The chosen concept

The GSO development is a subsea satellite development with two new templates. One production template and one gas injection template. These templates shall be tied-in to the Gullfaks A platform by using existing flowlines and equipment. The D-template has been producing since 1998 and has produced much of its reservoir content. This template has one separate 8" flowline. This flowline shall be decommissioned at towhead N2/S1 showing in figure 2.9, and a new template from the GSO development shall be tied-in at that 8" at the towhead.

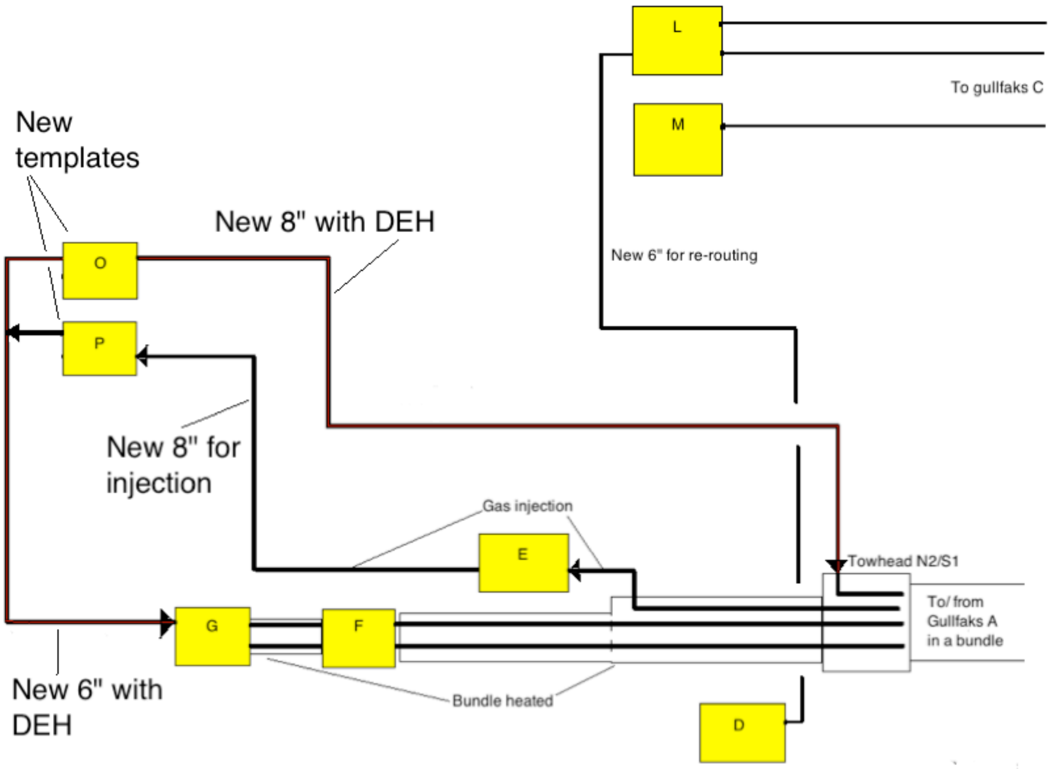

Figure 2.10 The GSO development with template O and P and new flowlines.

The GSO project is a further subsea satellite development of Gullfaks South reservoir with one 4-slot template with four producers, the O-template. And one 4-slot hybrid template with two gas injectors and two future producers, the P-template. These shall be tied-in to Gullfaks A. In addition will some existing subsea equipment be re-used, there will be extension of flowlines and umbilical from already installed and producing templates. The O-template will have a new 8” flowline tied-in on the towhead where D-template was. It will also have a new 6” flowline to the G-template and can co-produce with template G and F. There will also be installed a production jumper between O and P for future production wells. The injection template P will have a new 8” extended flowline from template E. Therefor the development will be some cheaper than a completely new subsea satellite development.

Figure 2.10 shows the new subsea layout after the GSO development, the new templates are O and P. Template D which today is producing to Gullfaks A shall be re-routed to Gullfaks C and a new 8” flowline from template O shall be installed at the towhead where D was connected. The reason for this is that it is getting short on J-tubes on Gullfaks A where new flowlines can be tied-in to the platform. The GSO project was not prioritized for a separate J-tube. In addition the D-template is in its end of production lifetime, it has to be shut-in for a while to gain reservoir pressure again. Therefor the D-template flowline will be de-commissioned on towhead N2/S1 and re-routed to the L-template and Gullfaks C, which are producing from the same reservoir section as D-template, this will make place for the O-template flowline. The main control of D-template will still be from Gullfaks A, since it is very expensive with a new umbilical.

The O-template is the new production template with four wells and the new P-template shall provide reservoir stimulation with two gas injectors. A new 8” production flowline with direct electrical heating (DEH) will be installed from O-template to towhead N2/S1. On the towhead the flowline will be tied-in to the existing bundle where template D is de-commissioned. The need for heating on the flowline will be highlighted under the flow assurance chapter.

The bundle showing in figure 2.11 consist of two 6” flowlines from template G and F, one 8” gas injection flowline and an 8” flowline where O-template is tied-in. A new 6” production flowline will also be installed from O-template to one of the G-templates 6” flowline. This increases the flexibility of production “directions”, if the wellhead pressure is varying or dropping in some of the wells it is possible to produce the wells different directions. This is for reducing the possibility of cross flowing between the wells, a high pressure-well could produce into a low-pressure well. Today the wellhead pressure on F-template is varying from 130 bar-190 bar [13], the wells on the O-template is expected to have a shut-in wellhead pressure above 300bars. Planned maintenance on the flowlines, e.g. valve leakage testing entails that the relevant flowline has to be shut down for a period. In that period it is still possible to produce the wells through the other flowline while testing is in progress. A new 8” gas injection flowline from template E to template P will be installed to provide injection gas to the reservoir. A jumper between O- and P-template will also be installed for future production wells on P-template.

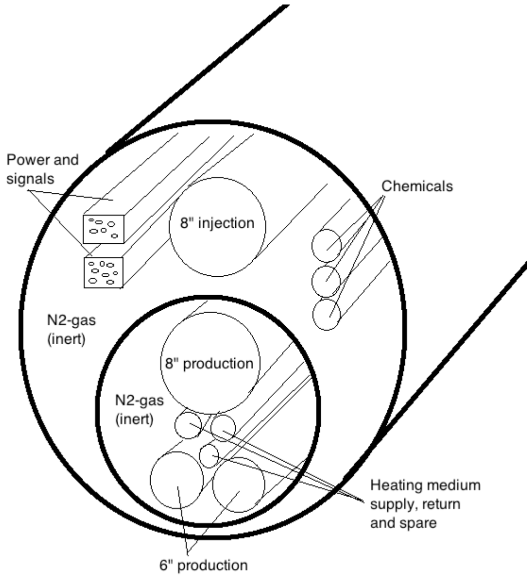

Figure 2.11 Cross section of the bundle

The umbilical that provides hydraulics, electrical power, control signals and chemicals for controlling and monitoring of the templates will be extended from the template G to O, and an umbilical jumper from O to P will be installed. To provide flow assurance on the new 8" flowline from O-template to the N2/S1 towhead and on the 6" flowline between O- and G-template, separate DEH cables that provide heat are mounted on each flowline. The DEH cable needs power and signal to function, a new power and signal cable is installed and laid from Gullfaks A to O-template.

Since the GSO project`s new flowlines are being tied-back to the already existing flowlines, the production rates must to be checked against the dimension of the flowline. The flowlines are also tied-in to the platform Gullfaks A where the process facilities are given and could give some limitations related to the production profile of the GSO.

The new flowlines for the GSO subsea satellite development that shall be further analysed are:

- One new 8" flowline from the O-template at 6200m is being tied into an existing flowline at the towhead. Total length of this flowline from O-template to the platform, including both the new and the old one is 8000m
- One new 6" flowline from the O-template to the G-template at 2200m. From the G-template the flowline will co-produce with the G-wells and thereafter the F-wells.

- One 8” extended flowline from the E-template to the P-template for gas injection. Total length of the flowline from the platform to the P-template is 8000m including the new and the old flowline.

2.8 Gullfaks A opportunities and limitations

Prior to the analyse of the well stream starts, it would be useful and interesting to see the opportunities and limitations by using Gullfaks A as the tie-in point of the GSO development.

The GSO development is a tie-in project and the economical investments are much lower since this is not a stand-alone project. GSO will be using the existing infrastructure on the Gullfaks A platform. By doing this there will be some limitations and overall criteria for the development. The Gullfaks A platform started to produce on the Gullfaks field in 1986 and is a stand-alone development. The platform has in principle all the necessary process facilities to manage the well stream from the new O-template. The process facilities consist of:

- Two parallel three stage oil trains, 1st stage separator with 56bar, 2nd stage separator with 18bar and the 3rd stage with 1,8bar. Throughout these separators the 3-phase well stream is separated to pure oil, gas and water. The two trains have a capacity of 32500 Sm^3/day of liquid (oil and water) and 159000 Am^3/day (actual flow, 56bar conditions) each [14].

- After the oil is separated through the 3rd stage separator it is stable, meaning the oil won’t gas of much any more and it is stable crude oil possible to store. The crude oil is stored on storage cells with a capacity of nearly 300000 Sm^3. Buoy loaders ships the oil to the marked regularly.

- The water that is separated from the well stream is treated of remaining oil and discharged to sea in accordance with discharge requirements. The water treatment system has a capacity of 60000 Sm^3/day [15].

- The gas is compressed and treated by two 4-stage gas compressor trains and gas treatment facilities. The gas is either sold to the gas treatment facility at Kårstø via the Statpipe pipeline, or it is further compresses by another gas injection compressor and injected into the reservoir for reservoir stimulation. The capacity for gas compression and treatment is 16 MSm^3/day and injection compressor can deliver a maximum pressure at 405 bars.

- Gullfaks A has four 20 MW generators, they have enough surplus to provide electrical power for the DEH cables. The platform contains equipment and systems to provide all necessary utility systems, like chemicals and hydraulics for the umbilical.

By having nearby facilities increases the possibilities for smaller developments like the GSO. This reduces the challenges for flow assurance, due to the nearby process facilities, and it can supply the development with necessary power and utility systems. However using nearby existing facilities means that there will be some limitations. Gullfaks A has been producing since 1986 and have several existing platform wells and subsea templates producing to the platform at this day. That implies that there are already users of the process facilities. One limitation is the arrival pressure at minimum 56 bars, which is the 1st stage separator pressure. The GSO flowlines must be checked and analysed for arrival pressure.

The total liquid stream, oil + water, through the two 1st stage separators are today ref. the Energy Components [13], Statoil Gullfaks measurement tool is approximately 18000 Sm^3/day. This is comfortably within the liquid capacity of the process facility on Gullfaks A and the liquid stream from GSO will not be threaten the design capacity of the process facility.

The amount of treated gas on Gullfaks A is today around 14 MSm^3/day ref Energy Components. This is only 2 MSm^3/day below the design capacity of the gas treatment facility. If we look back on figure 2.6, the gas production from O-template will exceed the design capacity already at year three of production. The production profile indicates that it will also continue to increase in gas amount the following years after year three. This will definitely be a limitation for the total possible HC production on Gullfaks A.

Having a gas injection compressor at Gullfaks A will provide the needed reservoir stimulation. Flowline pressure drop must be analysed for assure high enough injection pressure is possible.

2.9 Summary

Newer seismic surveys and analysis shows that the existing development tied-in to the nearby stand-alone platforms only has a recovery rate of 8%. Parts of the reservoir do not get drained of HC at all. A 4-D seismic survey shows that the reservoir was more complex than first anticipated, and more drainage points of the reservoir are needed to be able to increase the recovery rate. The complexity of the reservoir where several new drainage points are needed, and the need for reservoir stimulation with gas injection to keep the reservoir in liquid phase and drive the liquid out of the reservoir. Six wells shall be drilled preliminary to increase the recovery rate.

Six wells to be drilled from the nearest stand-alone facility with a derrick at a distance of approximately 8km holds too much uncertainty. The GSO concept solution became a subsea satellite development with two new templates where existing tie-in points shall be re-used. The production template O will have four producing wells and the gas injection template P will have two wells. These two new templates shall be tied-in to existing flowlines and the nearest stand-alone platform Gullfaks A. Tying-in to a platform will give both opportunities and limitations, the limitations must be checked if they could compromise the development. Umbilicals will also be extended from nearby templates for cost reduction. The re-use of existing flowlines will give some limitations due to fixed flowline diameters and must be analysed.

The production profile for the new O-template will be central for analysing and calculating the suitability for flowline design with respect to both the dimensions and flow assurance.

The new flowlines for the GSO subsea satellite development that shall be further analysed are:

- One new 8” flowline from the O-template at 6200m is being tied into an existing flowline at the towhead. Total length of this flowline from O-template to the platform, including both the new and the old one is 8000m
- One new 6” flowline from the O-template to the G-template at 2200m. From the G-template the flowline will co-produce with the G-wells and thereafter the F-wells.
- One 8” extended flowline from the E-template to the P-template for gas injection. Total length of the flowline from the platform to the P-template is 8000m including the new and the old flowline.

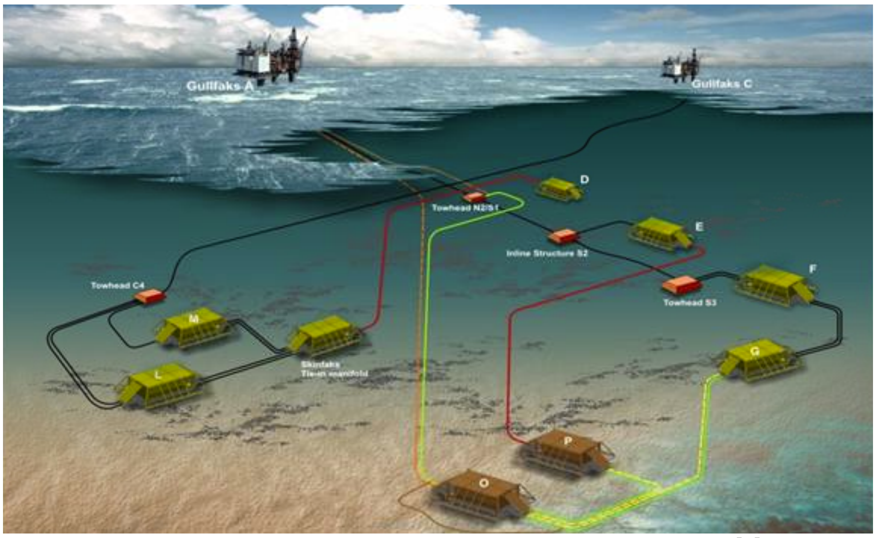

Figure 2.12 shows the GSO field with the two new templates O and P [3].

With the two new templates with four producing wells and two gas injectors it is estimated that the recoverable rate will be increased to 31% for the field.

3 Flowlines

Flowlines are an essential part of a subsea satellite development. These are going to transport the well stream from the X-mas tree to the production facilities. This chapter will give an introduction to the considerations that have to be accounted for when deciding the route where the flowline shall be laid and the design drivers for a flowline. Theory of pipeline stresses with respect to hoop- and longitudinal stresses will be given. Following will pressure loss during the transport of the well fluid due to the effect of flow rates and flowline dimensions properties be highlighted.

This theory will be applied to analyse the GSO specific flowlines.

3.1 Route and design drivers

Ideally a pipeline would be in a straight line between the two points, this would reduce the cost of the pipe and the pressure drop for the flow to a minimum. However this is seldom possible [16] due to:

- Seabed obstruction like platforms, wells, pipelines, shipwrecks.
- Seabed features, soil conditions, rocks, valleys,
- Other users of the seabed like fishing grounds, exclusion zones, and corals.
- Construction limitations, nearby platforms, pipeline crossing, bend radius.

There are several different aspects to be checked and analysed before one can choose a flowline. A flowline is the pipeline between the well/ manifold and the process facility. It is a regular pipeline but renamed to pinpoint which pipe that goes where. This is because it can be very many pipelines and flowlines on a seabed, especial nearby a platform. Design drivers for a pipeline:

- Medium - can it be corrosive on the material.
- External pressure – water depth of installation, can be design driver for the outer diameter, OD.
- Internal pressure - can be design driver for the internal diameter, ID.
- On bottom stability.
- Flow rate.
- Temperature changes.
- Pipe laying method

3.2 Pipe dimension, hoop stress and longitudinal stresses

Designing and choosing a flowline is a continuous operation. It is necessary to start with some initial criteria's, start to analyse, and then recheck the initial conditions for further designing. E.g. starts with an assumed pipe dimension then apply internal and external pressure for checking the wall thickness needed. The assumed pipe dimension has to be checked for flow capacity and flow rate. If ok, continue with on bottom stability, the pipe must be still on the bottom and not moving. This could damage the pipe and can threaten its integrity.

3.2.1 Hoop stress

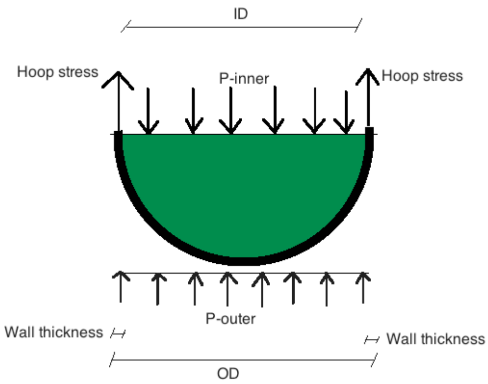

Figure 3.1 Hoop stress in a pipe

Figure 3.1 shows the relation between the dimension of the pipe and the pressure it is containing, P-inner and the surrounding pressure, P-outer. The hoop stress, σ_h, together with the wall thickness will give the strength of the pipe. The inner and outer pressure together with the material quality will give the needed wall thickness or other desired unknown. The relation is as followed in equation 3.1:

P_i	=	Inner pressure
Po	=	Outer pressure
t	=	Wall thickness
σ_h	=	Hoop stress
ID	=	Inner diameter
OD	=	Outer diameter

$$(\mathrm{Po} \cdot \mathrm{OD}) + (2 \cdot \sigma_h \cdot t) = (Pi \cdot ID) \qquad 3.1$$

If we know the ID we can solve it for wall thickness t by setting OD= ID+2t:

$$\mathrm{t} = \frac{ID \cdot (\mathrm{Pi} - \mathrm{Po})}{2 \cdot (\mathrm{Po} + \sigma_\mathrm{h})}$$

If we know the OD we solve it for wall thickness t by setting ID=OD-2t:

$$\mathrm{t} = \frac{OD \cdot (\mathrm{Pi} - \mathrm{Po})}{2 \cdot (\mathrm{Pi} + \sigma_\mathrm{h})}$$

Similar if we solve equation 3.1 for hoop stress, the material stress we get equation 3.2, hoop stress, σ_h:

$$\sigma_h = \frac{Pi \cdot ID - Po \cdot OD}{2 \cdot t} \qquad 3.2$$

SMYS- Specified Minimum Yield Strength is given from the chosen steel quality
Assuming a safety factor at 0,80 of SMYS giving hoop stresses $\sigma_h \leq 0{,}80 \cdot SMYS$ when calculating [17].

3.2.2 Longitudinal stress

When a pipeline is fixed in both ends, stresses will occur instead of extension and contraction from physical forces. Even if the pipeline is free to expand, the friction between the pipeline and soil will constrain the pipeline and stresses will occur. Longitudinal stresses in a pipe are the stresses in the longitudinal direction. These stresses arrive mainly from two features. The internal pressure will try to change the shape of the pipe, expand the diameter which will decrease the length of the pipe. This is called the Poisson effect.

The second feature is the effect from temperature changes in the pipeline, most material will have an effect of temperature difference. Metals will extend when heated and contract while cooled down, this longitudinal stresses are created from the temperature effect on the material.

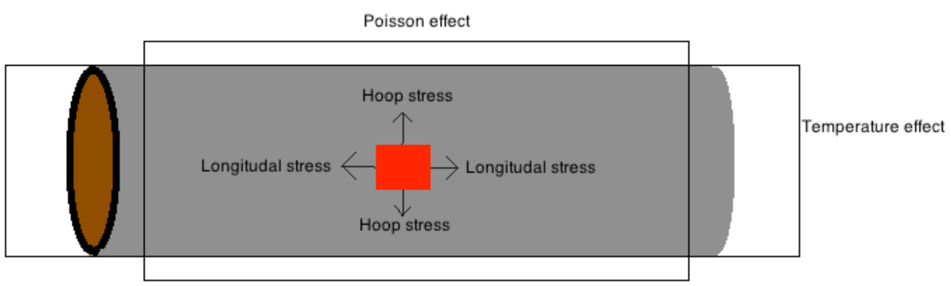

Figure 3.2 Longitudinal stress

The longitudinal stresses created by the pressure are a ratio of the Hoop stress given from the internal and external pressure, and the inner and outer diameter of the pipeline. The Hoop stress with the material factor, the Poisson ratio, gives the Poisson effect of the stresses. The temperature changes together with the material properties: modulus of elasticity and the coefficient of thermal expansion gives the longitudinal stresses created by temperature changes.

Longitudinal stresses are given from equation 3.3

$$\sigma_L = (\sigma_H \cdot v) - (E \cdot \alpha \cdot \Delta T) \qquad 3.3$$

Where:

σ_L	=	Longitudinal stress	$[MPa]$
σ_H	=	Hoop stress	$[MPa]$
v	=	Poisson ratio	$[Dimension\ less]$
E	=	Modulus of elasticity	$[MPa]$
α	=	Coefficient of thermal expansion	$\left[\frac{1}{°C}\right]$
ΔT	=	Temperature changes	$[°C]$

The negative sign in front the temperature part of equation 3.3 is due to the two different stresses are acting in the opposite direction of each other.

3.2.3 Equivalent stresses

According to DNV GL [16] combining the hoop stresses and the longitudinal stresses acting together, the Von Mises criteria is applicable and gives the equivalent stresses showing in equation 3.4.

$$\sigma_e = \sqrt{({\sigma_H}^2 + {\sigma_L}^2) - (\sigma_H \cdot \sigma_L)} \qquad 3.4$$

Where:

σ_e	=	equivalent stress	$[MPa]$

The equivalent stresses should not exceed the SMYS of the pipeline construction material combined with a safety factor.

3.3 Flow rates and pressure drop

Flow rates through the flowline are also an essential parameter for dimensioning. Velocity of the fluid and fluid content will concern the flow assurance and erosion that will be further discussed under the flow assurance chapter. Size and shape of the pipe, pipe surface and flow rate and fluid property decides the pressure drop of the fluid through the pipe. This pressure drop together with the pressure drop due to the height difference must not be greater than the process facilities inlet pressure.
To calculate the pressure drop in the pipe the following data is needed, either by determine or calculation:

- Pipe area.
- Pipe surface roughness.

- Flow rate.
- Fluid properties: density, kinematic viscosity that will give the Reynolds number.
- The Reynolds number tells us of which regime the fluid is flowing in, laminar or turbulent.

The Reynolds number is given from the equation 3.5

$$Re = \frac{Inertial\ forces}{Viscous\ forces}$$

$$Re = \frac{ID \cdot v}{\upsilon} \qquad 3.5$$

Where:

Re	=	Reynolds number	$[Dimensionless]$
ID	=	Inner diameter of the pipe	$[m]$
v	=	Fluids velocity	$\left[\frac{m}{s}\right]$
υ	=	Fluids kinematic viscosity	$\left[\frac{m^2}{s}\right]$

Finding the flow regime and Re-number next step is to use the Moody-diagram to find the Darcy friction factor.

Darcy-Weisbach`s is an empirical equation derived to calculate the pressure loss in a pipe due to friction forces and no-slip forces on a wall. Darcy-Weisbach`s equation 3.6 is as followed for a straight circular pipe [18]:

$$\Delta P = f \cdot \frac{\rho \cdot v^2 \cdot L}{2 \cdot D} \qquad 3.6$$

Where:

ΔP	=	pressure drop	$[bar]$
f	=	Darcy friction factor	$[dimensonless]$
ρ	=	fluid density	$\left[\frac{kg}{m^3}\right]$
v	=	fluid velocity	$\left[\frac{m}{s}\right]$
L	=	pipe length	$[m]$
D	=	pipe diameter	$[m]$

It is also necessary to include the pressure drop due to the height difference between the seabed and the process facility, which is: $\rho \cdot g \cdot h$ where:

g = Gravity acceleration
h = Height difference

Thus the total pressure drop will be:

$$\Delta P = f \cdot \frac{\rho \cdot v^2 \cdot L}{2 \cdot D} + \rho \cdot g \cdot h \qquad 3.7$$

3.4 GSO flowline analysis

The GSO development will re-use some of the existing subsea infrastructure on the seabed of the Gullfaks field. This results in some limitations and conditions that the design for the new flowlines has to be accounted for. The flowline shall be tied-in on the towhead showing in figure 2.10, this is a tie-in on an 8" production flowline. For the new flowline to be installed it needs to match the tie-in point, which is 8", meaning the new flowline from the O-manifold will be 8". It could be possible to make a larger flowline with a conical reduced connector at the towhead, but it would still be 8" from the towhead and up to the platform, which also could implicate the flow regime and flow assurance and therefor not a convenient solution either. The maximum wellhead pressure is given at 390 bars and the water depth for the flowline to be installed is 134m below sea level. The choice of materials depends somewhat of the fluid content, well stream from an oil reservoir may be or will to certain degree be corrosive due to content of H_2S and CO_2. Therefor a natural choice is to choose a corrosion resistant steel alloy. The data sheet of the "old" flowlines that the new ones is tie-in to giving the actual measurement of the outer diameter (OD) of the 8" flowline is 219,9 mm and wall thickness is 11 mm, giving the inner diameter to be 197,1 mm. The 6" flowline has an OD at 168,3mm and ID at 151,3mm giving a wall thickness at 8,5mm. The material is a 13%Cr stainless steel alloy, which has a SMYS to be 550 MPa ref. DNV OS F101. To avoid any galvanic corrosion between the new and the old flowline, it is sensible to use the same steel alloy for the new flowlines as well.

The injection flowline is an 8" that shall be extended from the E-template to the P-template. The maximum pressure that the injection compressor can deliver is 405 bars, the design pressure for the flowline shall be 450 bars to include for some uncertainties and the steel grade is X65 [2]. The X65 refers to 65 KSI that are converted to 448 MPa. To match the tie-in point for the flowline, the OD is 219,1 mm and wall thickness is 14 mm giving the OD to be 191,1 mm.

3.4.1 Production flowline strength 6" and 8"

By having the information of material quality, water depth and reservoir properties, it is possible to estimate the maximum hoop stress and longitudinal stresses in the pipe. To check that the new conditions do not threaten the pipe integrity, both for the new and old pipes. Hoop stresses are found by applying equation 3.2, longitudinal stresses applying equation 3.3 and the equivalent stresses of these by using equation 3.4.

Assumptions:

- 8" flowline having OD=219,9mm and ID=197,1mm.
- 6" flowline having OD=168,3mm and ID=151,3mm.
- Material is 13%Cr with SMYS at 550MPa.
- E-modulus=200000Mpa and temperature coefficient is $1{,}12 \cdot 10^{-5}\,\frac{1}{°C}$.
- Maximum wellhead shut-in pressure is 390 bars = maximum flowline pressure.
- Maximum wellhead temperature is 90°C = maximum flowline pressure.
- Ambient pressure is 13,4 bar at water depth of 134m.
- Ambient seawater temperature is 7°C.

8"flowline from O-template to towhead:

Maximum hoop stress will be:

$$\sigma_h = \frac{\mathrm{Pi} \cdot \mathrm{ID} - \mathrm{Po} \cdot \mathrm{OD}}{2 \cdot \mathrm{t}}$$

$$\sigma_h = \frac{39\mathrm{Mpa} \cdot 197{,}1\mathrm{mm} - 1{,}34\mathrm{Mpa} \cdot 219{,}1\mathrm{mm}}{2 \cdot 11\mathrm{mm}}$$

$$\sigma_h = 336\ MPa$$

$$\sigma_h < 0{,}8 \cdot SMYS \rightarrow ok$$

$$336 < 440 \rightarrow ok$$

Maximum longitudinal stresses will be:

$$\sigma_l = \sigma_h \cdot \nu - E \cdot \alpha \cdot \Delta T$$

$$\sigma_l = (336 \cdot 0{,}3) - (200000 \cdot 1{,}12 \cdot 10^{-5} \cdot 83)$$

$$\sigma_l = -98{,}4\ MPa$$

Equivalent stresses from the hoop- and longitudinal stresses are:

$$\sigma_{eq} = \sqrt{(\sigma_h{}^2 + \sigma_l{}^2) - \sigma_h \cdot \sigma_l}$$

$$\sigma_{eq} = \sqrt{(336^2 + (-98{,}4)^2) + 336 \cdot 98{,}4}$$

$$\sigma_{eq} = 395$$

$$395 < 440 \rightarrow ok$$

6" flowline from O-template to G-template:

Maximum hoop stress will be:

$$\sigma_h = \frac{Pi \cdot ID - Po \cdot OD}{2 \cdot t}$$
$$\sigma_h = \frac{39Mpa \cdot 151{,}3mm - 1{,}34Mpa \cdot 168{,}3mm}{2 \cdot 8{,}5mm}$$

$$\sigma_h = 334\ MPa$$
$$\sigma_h < 0{,}8 \cdot SMYS \rightarrow ok$$
$$334 < 440 \rightarrow ok$$

Maximum longitudinal stresses will be:

$$\sigma_l = \sigma_h \cdot \nu - E \cdot \alpha \cdot \Delta T$$
$$\sigma_l = (334 \cdot 0{,}3) - (200000 \cdot 1{,}12 \cdot 10^{-5} \cdot 83)$$
$$\sigma_l = -99\ MPa$$

Equivalent stresses from the hoop- and longitudinal stresses are:

$$\sigma_{eq} = \sqrt{(\sigma_h{}^2 + \sigma_l{}^2) - \sigma_h \cdot \sigma_l}$$
$$\sigma_{eq} = \sqrt{(334^2 + (-99)^2) + 334 \cdot 99}$$
$$\sigma_{eq} = 393$$
$$393 < 440 \rightarrow ok$$

Equivalent stresses from hoop and longitudinal stresses are within the design criteria with a good margin for both the 6" and 8" flowline including a safety factor at 0,8. The old flowlines as well as the new are suitable for the GSO development. The flowlines will keep their integrity with a maximum wellhead pressure at 390 bars and installed in a water depth at 134 m. It is assumed that the old flowlines are inspected and not degraded with respect to corrosion and wall thickness.

3.4.2 Production flowline pressure loss 6" and 8"

The stresses from the well pressure and the flowlines surroundings are within the criteria and it is possible to check these design measurements with respect to flow and pressure losses. The production rates from the O-template are shown in figure 2.6 and table 2.1. If we consider the 8" flowline and take a closer look at year three of production where the total liquid production is at its highest and include the gas production, we can estimate the flow rate and the flow regime to check the suitability of the pipe size. Since the gas rates are listed in Standard cubic meters which are at 101,125 kPa and 15°C

conditions, it is necessary to convert the rates over to flowing conditions. Flowing conditions will vary over time and it is necessary to make some assumptions to be able to estimate the flowing regime. The wellhead shut-in pressure will be quite high at the first, but if the reservoir will behave like the nearby wells it is believed that the pressure will decline relatively shortly after production start.
Assumptions year three of production:

- Flowing pressure = 190bar
- Flowing temperature= 90℃
- Ideal gas law is applicable for methane gas
- Water is incompressible with density $1000\frac{kg}{m^3}$
- Oil is incompressible with density $825\frac{kg}{m^3}$
- Pipe roughness 0,05mm
- Total flowline length is 8km and can be considered as a straight line due to pig-able pipe.
- Height difference from seabed to platform facility is 175m

By using the ideal gas law, equation 3.8. It will be some small errors, normally less than 1% error, but still gives a fairly good estimate. By using the ideal gas law it is possible to convert the volume of the gas from one state to another [6: 136].

Gas production:

$$\frac{P_1 \cdot V_1}{T_1} = \frac{P_2 \cdot V_2}{T_2}$$

By re-arranging and solving for V_1 we will get:

$$V_1 = \frac{P_2 \cdot V_2 \cdot T_1}{T_2 \cdot P_1} \qquad 3.8$$

$$V_1 = \frac{1bar \cdot 1m^3 \cdot (273 + 90)°K}{(273 + 15)°K \cdot 190bar}$$

$$V_1 = 6{,}63 \cdot 10^{-3} m^3$$

V_1 indicates the volume of 1 Standard cubic meter at flowing conditions at 190 bars and 90℃. Transforming the Standard conditions over to desired conditions and units for calculations we get:

$$2827669\frac{Sm^3}{day} \rightarrow 18747\frac{m^3}{day} = 0{,}22\frac{m^3}{s}\ at\ 190bar\ and\ 90℃$$

Oil production:

$$2195\frac{m^3}{day} = 0{,}025\frac{m^3}{s}$$

Water production:

$$518\frac{m^3}{day} = 0{,}006\frac{m^3}{s}$$

Total production:

$$0{,}251\frac{m^3}{s}$$

The pipe inner diameter=197,1mm gives the flowing area=0,0305m^2
Total flow velocity:

$$v = \frac{0{,}251\frac{m^3}{s}}{0{,}0305m^2} = 8{,}23\frac{m}{s}$$

Percentage distributed of each fluid:

- Oil – 10%
- Gas – 87%
- Water – 3%

Kinematic viscosity from Engineering tooling box:

- Oil – $23 \cdot 10^{-6}\frac{m^2}{s}$
- Gas – $0{,}16 \cdot 10^{-6}\frac{m^2}{s}$
- Water – $0{,}32 \cdot 10^{-6}\frac{m^2}{s}$

Composed fluids gives a kinematic viscosity at $2{,}45 \cdot 10^{-6}\frac{m^2}{s}$.

Applying the equation 3.5 to find the flow regime of the well stream.
Reynolds number Re:

$$Re = \frac{0{,}1971m \cdot 8{,}23\frac{m}{s}}{2{,}45 \cdot 10^{-6}\frac{m^2}{s}}$$

$$Re = 662095$$

Based on the calculation, the fluid flow is in the turbulent area. There are some uncertainties of the given viscosities since these will change in both temperature and pressure, but this indicates strongly that the flow is turbulent even with some errors.

The relative roughness is given from $\frac{steel\ roughness}{inner\ diameter} = \frac{0{,}05mm}{199{,}1mm} = 2{,}5 \cdot 10^{-4}$
Based on the relative roughness and Re number the Darcy friction factor (f) is read from the Moody diagram (attached in the appendix) and it is approximately 0,014.

The density of the gas will increase as it is getting compressed. Methane has a density of approximately 0,8 $\frac{kg}{m^3}$ in Standard conditions.

$$2827669 \frac{Sm^3}{day} \cdot 0{,}8 \frac{kg}{Sm^3} = 2262135 \frac{kg}{day} = 26{,}2 \frac{kg}{s}$$

$$\frac{26{,}2 \frac{kg}{s}}{0{,}22 \frac{m^3}{s}} = 119{,}1 \frac{kg}{m^3}$$

Calculated from Standard conditions over to flowing conditions at 190bar and 90°C gives a new gas density at 119,1 $\frac{kg}{m^3}$.
Oil and water is assumed incompressible and has the following densities:
Oil – 825$\frac{kg}{m^3}$
Water – 1000$\frac{kg}{m^3}$
Giving a composed fluid density at 216,1$\frac{kg}{m^3}$.
By entering these numbers in to the total pressure loss formula, eq. 3.7, we get the loss pressure due to friction loss and height difference.

$$\Delta P = f \cdot \frac{\rho \cdot v^2 \cdot L}{2 \cdot D} + \rho \cdot g \cdot h \tag{3.7}$$

$$\Delta P = 0{,}014 \cdot \frac{216{,}1 \frac{kg}{m^3} \cdot \left(8{,}23 \frac{m}{s}\right)^2 \cdot 8000m}{2 \cdot 0{,}1971} + 216{,}1 \frac{kg}{m^3} \cdot 9{,}81 \frac{m}{s^2} \cdot 175m$$

$$\Delta P = 4156758 + 370818\ Pa = 4527577Pa = 46bars$$

At year three of production with the assumption made there will be a turbulent flow through the flowline. This gives 46 bars pressure drop and will not be a challenge for the arrival pressure at the process facility.

By assuming the initial pressure and temperature conditions throughout the production life of the producing wells, the following table is made showing the pressure loss of full production through either the 6” or the 8” flowline. The 6” flowline is only calculated from O-template to arrival at G-template since other production wells will be producing on the same flowline from there and will contribute to the further calculations to platform arrival. The initial production conditions are at the start of the flowline, downstream the subsea choke regulator.

Table 3.1 Pressure loss

Initial conditions			8" 8000m flowline		6" 2200m flowline	
Production Year	Production pressure in bar	Production temperature in °C	Pressure loss 8" in bar	Arrival pressure at platform in bar	Pressure loss 6" in bar	Arrival pressure at template G
1	180	80	6	174	0	180
2	185	85	10	175	6	179
3	190	90	44	146	42	148
4	185	89	46	139	44	141
5	180	88	67	113	66	114
6	175	87	66	109	65	110
7	170	86	64	106	64	106
8	165	85	63	102	63	102
9	160	84	63	97	63	97
10	155	83	63	92	63	92
11	150	82	63	87	63	87
12	145	81	64	81	64	81
13	140	80	65	75	65	75
14	135	79	65	70	65	70
15	130	78	21	109	20	110
16	125	77	22	103	21	104
17	120	76	12	108	11	109
18	115	75	6	109	5	110
19	110	74	3	107	2	108

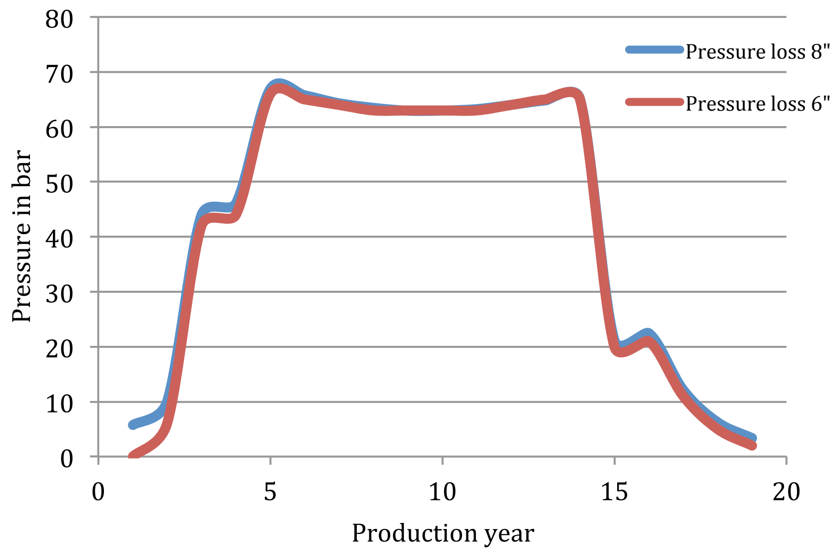

Figure 3.3 Pressure loss

Production flowline summary

The flowlines are within the stress criteria for the new GSO reservoir properties and ambient surroundings. Re-use the existing flowlines and extend these to template O with equivalent material quality is applicable for the GSO development.

Arrival pressure on the platform and to the G-template will not be a challenge for the fixed diameters due to pressure loss of the GSO development. Table 3.1 and figure 3.3 are calculated with the assumed pressure and temperature evolution given in table 3.1 during the production profile. With these assumptions the pressure loss through the flowline including the height difference for each year will be within the needed arrival pressure at the separator. The pressure loss is at its highest when the gas production is highest, from year 5 until year 14. This is due to the flow velocity, which has a great influence at the pressure loss. The flow velocity will be highlighted under the erosion chapter. The 6" flowline is only calculated to the arrival at template G due to unknown co-producers from this stage.

3.4.3 8" injection flowline

The injection compressor delivers a maximum pressure at 405 bar, after the gas is compressed it is cooled down to 50°C and it will be further cooled down in the flowline by the ambient surroundings. Assuming the 8" injection flowline shall provide a total at 2 million Sm^3/day of gas for the P-template to keep the reservoir above the bubble point at 385 bars. To be able to maintain this pressure, the pressure loss in the flowline from the compressor to the template must not be too large. The static pressure will be in favour for the total pressure injection.

8" injection flowline strength

Assumptions:

- 8" flowline having OD=219,9mm and ID=191,1mm.
- Material is X65 with SMYS at 448MPa.
- E-modulus=200000Mpa and temperature coefficient is $1{,}12 \cdot 10^{-5}\,\frac{1}{°C}$.
- Maximum flowline pressure is 450 bar including static height and uncertainties.
- Maximum flowline temperature is 50°C.
- Ambient pressure is 13,4 bar at water depth of 134m.
- Ambient seawater temperature is 7°C

Maximum hoop stress will be:

$$\sigma_h = \frac{Pi \cdot ID - Po \cdot OD}{2 \cdot t}$$

$$\sigma_h = \frac{45\text{Mpa} \cdot 191{,}1\text{mm} - 1{,}34\text{Mpa} \cdot 219{,}1\text{mm}}{2 \cdot 14\text{mm}}$$

$$\sigma_h = 296\ MPa$$
$$\sigma_h < 0{,}8 \cdot SMYS \rightarrow ok$$
$$296 < 358 \rightarrow ok$$

Maximum longitudinal stresses will be:

$$\sigma_l = \sigma_h \cdot \nu - E \cdot \alpha \cdot \Delta T$$
$$\sigma_l = (296 \cdot 0{,}3) - (200000 \cdot 1{,}12 \cdot 10^{-5} \cdot 43)$$
$$\sigma_l = -8\ MPa$$

Equivalent stresses from the hoop- and longitudinal stresses are:

$$\sigma_{eq} = \sqrt{(\sigma_h{}^2 + \sigma_l{}^2) - \sigma_h \cdot \sigma_l}$$
$$\sigma_{eq} = \sqrt{(296^2 + (-8)^2) + 296 \cdot 98{,}4}$$
$$\sigma_{eq} = 300\ MPa$$
$$300 < 440 \rightarrow ok$$

The equivalent stresses are within the criteria and the injection pressure will be analysed for reservoir stimulation.

Injection pressure

Assumptions:

- Continuous injection of total 2 Sm^3/day.
- Flowing pressure = 370bar
- Flowing temperature= 50°C
- Ideal gas law is applicable for methane gas
- Pipe roughness 0,05mm
- Total flowline length is 8km and can be considered as a straight line due to pig-able pipe.
- Height difference from seabed to platform facility is 175m
- The flowline length is 8000m.
- The reservoir is assumed to be approximately 3200m below seabed level.

$$V_1 = \frac{1bar \cdot 1m^3 \cdot (273+50)°K}{(273+15)°K \cdot 370bar}$$
$$V_1 = 3{,}03 \cdot 10^{-3} m^3$$

$$2000000 \frac{Sm^3}{day} \rightarrow 6060 \frac{m^3}{day} = 0{,}07 \frac{m^3}{s}\ at\ 370bar\ and\ 50°C$$

This gives a velocity at $0{,}45\frac{m}{s}$ with an ID = 0,1911m

$$Re = \frac{ID \cdot v}{\nu} = 522638$$

$$2000000\frac{Sm^3}{day} \cdot 0{,}8\frac{kg}{Sm^3} = 1600000\frac{kg}{day} = 18{,}5\frac{kg}{s}$$

$$\frac{18{,}5\frac{kg}{s}}{0{,}07\frac{m^3}{s}} = 264\frac{kg}{m^3}$$

$$\Delta P = -f \cdot \frac{\rho \cdot v^2 \cdot L}{2 \cdot D} + \rho \cdot g \cdot h$$

$$\Delta P = -0{,}014 \cdot \frac{264\frac{kg}{m^3} \cdot \left(0{,}45\frac{m}{s}\right)^2 \cdot 8000m}{2 \cdot 0{,}1911} + 264\frac{kg}{m^3} \cdot 9{,}81\frac{m}{s^2} \cdot 3375m$$
$$\Delta P = -15666 + 8740710 = 8725044\ Pa$$
$$\Delta P = 87\ bar$$

Injection flowline summary

The injection pressure in the reservoir will be 370 bars from the compressor and 87 bars from the static pressure which adds up to 457 bars including the pressure drop at less than 0,2 bars due to the flowline roughness and gas velocity. This is sufficient to keep the reservoir above the bubble point at 385 bars. The pressure drop at only 0,2 bars due to the flowline indicate that it is possible to increase the injection rate if needed. Increased injection rate will increase the gas velocity, but 0,2 bars are within a good margin. The injection compressor will normally be varying some above and under the assumed 370 bars, this should not be to a concern. Even though the gas density will be reduced if the pressure is reduced, it will not be decisive due to the height difference. The static pressure will compensate for lower compressor pressure.

3.4.4 Flowline laying

The GSO development demands several new flowlines, three production flowlines and one injection flowline. All of these four flowlines are relatively short. The longest from O-template to the towhead are approximately 6,2km, the next from D-template to GFC is 4,3km and O- to G-template is 2,2km. The injection flowline extended from E- to P-template is 4,0km. The water depth around the GSO development and to Gullfaks A is only 134m, this is relatively shallow with respect to pipe laying. To lay a pipeline at this depth rule out the J-lay method. J-lay construction- and lay vessel has its construction facility vertical and the shape of the pipe will look like a J, therefor name J-lay.

The S-lay is more suitable for the depth, but due to short pipe length it would not be efficient to hire a large pipeline construction- and lay vessel for this purpose. The construction facilities are horizontal and the pipe shape of an S while laying, thereby the name S-lay.

The remaining reasonable alternative, which also is the most suitable for this operation is the reel lay. The production flowlines shall also have a DEH cable for flow assurance attached to them, this is possible by choosing a reel lay vessel with two reels. One for the flowline and the other for the DEH cable, then attach them together while they are reeled out.

By choosing the reel lay method the operational costs for vessel hire is reduced due to short lay time. The flowline is pre welded onshore in large manufacturing facilities and reeled on board a vessel suitable for the installation area showing in figure 3.4.

Figure 3.4 Apache II reeling on-board a pipeline [19].

Since the whole pipeline length is welded together in one length, there is no need for large construction space on-board, which makes the vessel smaller and more easily to manoeuvre in tight areas such as nearby platforms than other lay vessels. The North Sea can be a harsh environment regards to marine operations, the wave and wind forces are a limitation for the marine operations. The reel lay will provide a short and efficient pipe lay and can use the weather forecast to predict and plan the operational window quite easy. This reduces the probability of the phenomena “waiting on weather”, which basically is the vessels weather limitations, the operational time will be at minimum and thereby the costs will be to a minimum. There are also obstacles as existing flowlines and templates that need to be accounted for in the lay-path.

All flowlines are to be rock dumped both for protection from external loads and stability reasons.

3.4.5 Tie-ins

All flowlines and umbilicals need to be tied-in to their respective connection points after they are laid. The 8” production flowline from O-template to the towhead, the 6” production flowline from the O- to the G-template, and the 8” injection flowline from P- to the E-template. All of the flowline tie-ins are of the UTIS (Universal Tie-In System) sort. Where the two flanges will be attached together with a clamp that seals the surfaces with forces. All tie-in points are with UTIS connection.

Both Aker Solutions and FMC are making suitable tie-in systems for these flowlines.

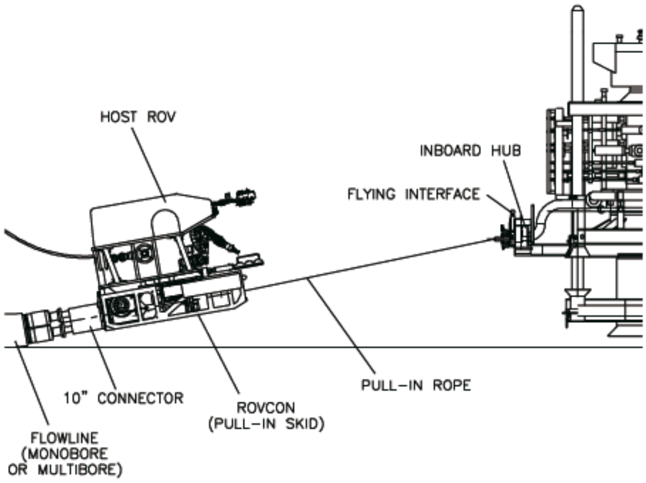

Figure 3.5. FMC`s ROV with UTIS [20].

These two manufactures have both designed and developed horizontal tie-in systems that are based on assistance from a working class ROV (Remote Operated Vehicle). The main component in the tie-in system, the pull-in skid uses wires or ropes that are attached to the tie-in point and pulls itself into place, example showing in figure 3.5. The ROV is lifting the free end of the flowline and supplying the pull-in skid with hydraulic power. A clamp-on is mounted outside of the two flanges when they meet and provides moment that seals the connection surfaces together, the UTIS. All tie-in operations will be a marine operation that has to be accounted for in the marine activity plan.

Tie-in to the G-template:

The G-template has two 6” flowlines, all the G-wells have a connection to both the flowlines via the manifold. At the end of the manifold there is installed a pig-loop that allows for round-pigging of these two flowlines from and to the Gullfaks A platform. This pig-loop will be removed and the 6” flowline from O will be tied-in to one of these flowlines. The other one will be closed with a HP (high-pressure) cap.

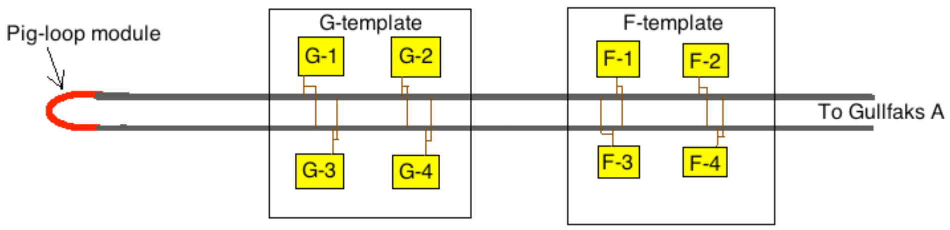

Figure 3.6 Existing layout with pig-loop

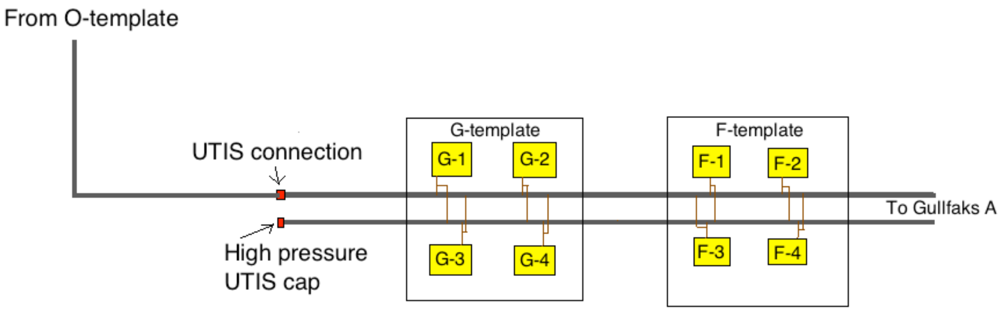

Figure 3.7. O-template tied-in to the G-manifold

Tie-in to the E-template from P-template:
This will be quit similar to the tie-in on the G-template. The difference here is that it is a HP plug at the end of the manifold that will be removed to make place for the tie-in.

Tie-in to the towhead from O-template:
The existing D-flowline will be disconnected at the UTIS at the towhead and re-routed to Gullfaks C. The O-templates 8" flowline will be tied-in to this UTIS connection point at the towhead.

All tie-in connections must be leak tested. The relevant systems should be water filled and pressurized, a pressure hold test over a given time period will give a test result. To confirm the leak tests, a ROV should inspect the connection points under the test. Since this is subsea and small leakages can be hard to discover, dye-mix is recommended for a better visibility.

3.5 Flowline summary

The GSO development will re-use existing flowline by tying-in to new production flowlines to existing structure. By doing this it is assumed that the material for the new and old flowlines are the same to avoid galvanic corrosion, the material used is a 13%Cr stainless steel. To match the tie-in points its believed that new flowlines will have the same dimensions as the old ones. With these assumptions together with the maximum production pressure and temperature and ambient surroundings, the equivalent stresses from hoop- and longitudinal stresses are within the material strength with a safety factor for both the 6" and 8" flowline.

Using the ideal gas law, the gas rates from the production profile are transformed to flowing conditions. Total well stream velocity and composed density are calculated to analyse the pressure drop with the use of Darcy-Weisbach`s empirical formula and the Darcy factor for both the production flowlines. The 8" flowline are calculated from the X-mas tree and to the arrival of the platform and will have a sufficient arrival pressure for all production years according to the production profile. The 6" flowline are calculated from the O-template to arrival at the G-template, this is due to the sharing of flowline from this point of the G-well and after the F-wells. The pressure drop to this point will be within the criteria for all production years, but it will have a pressure drop from the G-template to arrival at the platform as well. Meaning the 6" flowline would probably not be suitable for full production from O-, G- and F-template when O-template is producing at its most. However having to separate flowlines increases the flexibility of producing the O-template if needed.

The use of a relatively large diameter gas injection flowline, the pressure loss from the platform to the template will be minimal due to low gas velocity. With a gas injection compression pressure of 370 bars, with including the static height 87 bars and the pressure loss at 0,2 bar stimulate the reservoir pressure above the bubble point of 385 bars. It should also be possible to increase the flow rate without comprising the total injection pressure due to the pressure loss. Reduced compressor pressure is also possible.

Due to the length and diameter of the flowlines, together with relatively shallow water it is used a reel-lay vessel for installing the flowlines. This will reduce the offshore installation time and most likely unwanted waiting on weather for the vessel. Tie-in will be done with the UTIS, the existing and the new connections are UTIS. Several vessels with working class ROVs can do this operation using either Aker or FMC tool.

4 Flow assurance

In a subsea satellite development where untreated 3-phase well stream shall flow from the X-mas tree and to the process facilities, a good flow assurance is essential. Several subsea developments have been compromised due to bad flow assurance analysis and measures. Flowlines have gotten completely plugged by hydrates or wax [21]. In this chapter I will introduce the term “flow assurance” which is a description of how a fluid flows.

Theory of the different flow assurance challenges like slugging, hydrates, wax, corrosion and erosion will be explained. Origins of these challenges and measures to keep good flow assurance.

The GSO development will be analysed with these flow assurance titles to check the suitability for the flowlines, with mostly focus on slugging, hydrates, wax and erosion.
The gas injection will not be included here because this gas is a single-phase flow, already treated and will have minimal flow assurance challenges.

4.1 Flow assurance definition

Flow assurance is a description of the flow of a given fluid composition, the fluid needs to be transported to its location in a safe, technical feasible and economical way. Flow assurance is one of the main reasons that offshore oil platforms are needed. Single phase, pure fluids seldom have any flow assurance challenges, this is due to they are in a stable condition. The word flow assurance appeared when the oil and gas industry occurred and needed to transport the reservoir fluids. The reservoir contains HC, which is a wide term and may be advanced chemistry. HC means all sorts of hydrocarbon bindings, C1, C2, C3 and so on up to the heavier components C10+. These bindings are in gas and liquid form, and sometimes the can occur in both states depending on the pressure and temperature. Together with the HC, the reservoirs normally always contain some water and this water will be produced together with the HC. Therefor will the reservoir fluids containing gas, oil and water be a multi-phase transport flow. In additions to the HC gas in the reservoir, it can contain other gases such as N_2, H_2S and CO_2. Some of these gases are very corrosive that can lead to different types of corrosion on some materials. As described in the reservoir chapter, the desired HC that are to be produced is located inside rocks. Draining HC out of these rocks, some solids may follow the well stream when flowing. These multi-phases well streams can give flow assurance challenges depending on the amount of content, especially water, the HC chemistry and the flow regime of the fluid inside the flowline. [22]

Flow assurance subject:

- Slugging

- Hydrates
- Scale
- Wax
- Corrosion
- Erosion

4.1.1 Slugging

Slugging is when a multi-phase stream in a pipeline is separating its self to alternating liquid and gas stream.

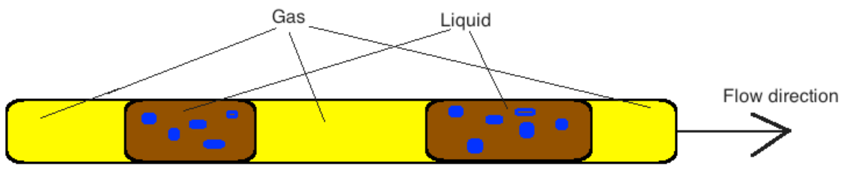

Figure 4.1 Illustration of slugging.

Slugging is a potential dangerous phenomenon that can threaten equipment integrity and lead to equipment damage. When the liquid slug is arriving at an obstruction like a sharp pipe bend, a valve or the inlet-arrangement in a separator it can crush it due to the liquid hammer. A liquid slug can be several hundred meters in some occasions, and the potential energy due to velocity and volume can be tremendous. Vibrations of continuous alternating slugging can lead to fatigue failure in a pipeline, especially if the vibrations will reach the resonance amplitude of the pipe.

Slugging can also reduce the production efficiency of a process facility because normally a process facility cannot handle very quick variations of liquid/gas. Reduced production efficiency is meant by a local or full unplanned process stop. In addition a slugging well stream is very work comprehensive and time consuming situation for the operator that controls the well stream, to keep the production efficiency high by doing manual interventions.

There are several reasons and situations that make slugging occur:

- Terrain slugging is due to natural hills and valleys on the seabed. Liquid can accumulate in the low points, pressure will build up behind the liquid until the hydrostatic pressure is overcome and a slug is occurred.

- Riser slug is in principle the same as a terrain slug. The difference is that riser is close to the process facility and will have a direct influence of the process due short appearance from the platform.

- Pig slug is a slug made with intention to remove liquid and other flow assurance aspect along the pipeline during operation. A pig is used to “clean” the pipe from settlements including liquid, the pig is routed to a pig receiver that can handle the liquid slug.

- Hydrodynamic slug comes from the flow regime in a pipe. If a pipe has a large diameter and the flow is relatively small, the whole pipe will act as a separator. This will lead to a laminar flow, a laminar multi-phase flow will experience internal boundary layers between the phases. Due to the viscosity difference between the phases the shear-forces will create a no-slip boundary condition between the phases. Gas has lower dynamic viscosity than oil and will therefor flow at a higher velocity than the oil. The velocity difference between the phases and no-slip condition between the layers will make the gas push and create waves on the liquid/ oil. The waves will grow larger and larger as flow is evolving over a distance. At some point the waves will be so big that it is blocking the whole cross section of the pipe. This is the start of a hydrodynamic slug, the blocking wave will push all liquid in front of it self and the slug will grow longer and longer. A larger gas slug will grow behind the liquid pushing the liquid in front. The size of a hydrodynamic slug is typically less than $500 \cdot ID$

It is important to understand the reasons why slugs occur. By this it is possible to do measures to reduce the likelihood of slugs. Mitigations of slugs are depended on which types of slugs that are occurring. The terrain slugs can be avoided if it is possible to re-route the pipeline outside of the greatest valleys and hills. The pipe may be some longer, but consequences of terrain slugging may be avoided.

Risers are needed to get the well stream on board the platform and there will be a high "climb" for the fluid at that point. Several oil companies has developed an active choke-regulator to choke down the well stream when liquid that has accumulated in the riser is slugging on board towards the process facilities. This is based on several pressure and flow gauges along the riser to measure when the liquid slug has enough backpressure to climb up the riser. When the slug is arriving the platform the active choke will reduce its opening to let the liquid in to the facilities in a controlled manner. This is both to protect equipment to get damaged, in worst case an HC leakage to air, and for avoiding process disturbance due to "slow" separator valves and compressor regulating [23].

Pig-operations are planned for to reduce some of the some flow assurance challenges and one of the tasks for a pig is to remove liquid from the pipeline. Therefor it is expected that liquid slugs will arrive together with the pig. If the slugs are getting too large, it is an indication that pig operations is needed more often.

To avoid hydrodynamic slugs, the estimates of the production rates are very important throughout the whole lifetime of the field. Pipeline inner diameter is essential for the flow regime. The well stream from each well will vary over time and thus the flowline stream will vary from production start till production stop, both in content and volume.

Since the flow will vary over time, the design will be a compromise for the total production time. The most important design criteria to avoid hydrodynamic slugs are to assure a turbulent flow. Recall the equation 3.5 found in chapter 3 it is possible to analyse which flow regime the well stream is operating in.

$$Re > 2300 \rightarrow turbulent\ flow$$
$$Re = \frac{ID \cdot v}{\upsilon} \tag{3.5}$$

4.1.2 Hydrates

Hydrates are a chemical binding between HC and water. A hydrate is comparable with natural snow and ice. This phenomenon may be the largest flow assurance challenge for the oil and gas industry, especially flowlines where the multiphase stream appears mostly. Hydrates need some conditions to be able to form. The conditions for hydrates growth, challenges and measure will be studied in this chapter.

Conditions for hydrate formation:

- Small HC molecules, C-1, C-2, C-3 and sometime C-4.
- Free water available.
- High enough pressure, normally above 20 bars but hydrates may be stable at 10-15 bars in certain conditions.
- Low temperature, but higher than seawater temperature.

These four conditions needs to be fulfilled for a hydrate formation is starting to grow. A hydrate can block flowlines and pipelines making it impossible to flow trough. They can also block gauges and instrumentation that will lead to false readings, which potential can lead to dangerous situations and a poor production efficient due to regulating the well stream blindly. A hydrate plug with a delta pressure can loosen itself uncontrolled with potential energy to break equipment in its path.

Figure 4.2. Example of a hydrate blocking the entire pipeline [24].

The most producing reservoirs will produce water at some time, often over a longer period, which will allow for one hydrate condition, free water. The production profile for the GSO development, table 2.1, indicates water production throughout the whole production life. HC reservoirs do almost always contain some small gas molecule as methane and ethane, which the water can bind to. A reservoir has relatively high pressure and high temperature, this will of course vary from reservoir to reservoir. The pressure will decline some due to the lift height from reservoir till surface (X-mas tree) and during the production lifetime because of emptying the reservoir. By these natural conditions three out of four conditions of hydrate formation is fulfilled, only lacking the temperature condition.

Under normal production the well stream will flow to its process facility, the surroundings will cool down the fluid. How much it is cooled down is depended on the insulation of the flowline, the surroundings of the flowline, mass-flow, the fluid properties and how far it is transported until it is arriving the process facility. Under normal production the well stream must not be cooled down so far that hydrate can start to bind to a formation. If there is a process shutdown of different reasons, the well stream will be shut-in inside the flowline between the X-mas tree and riser valve. When this happens the fluid will immediately start to cool down, and will at one point reach the hydrate formation temperature point.

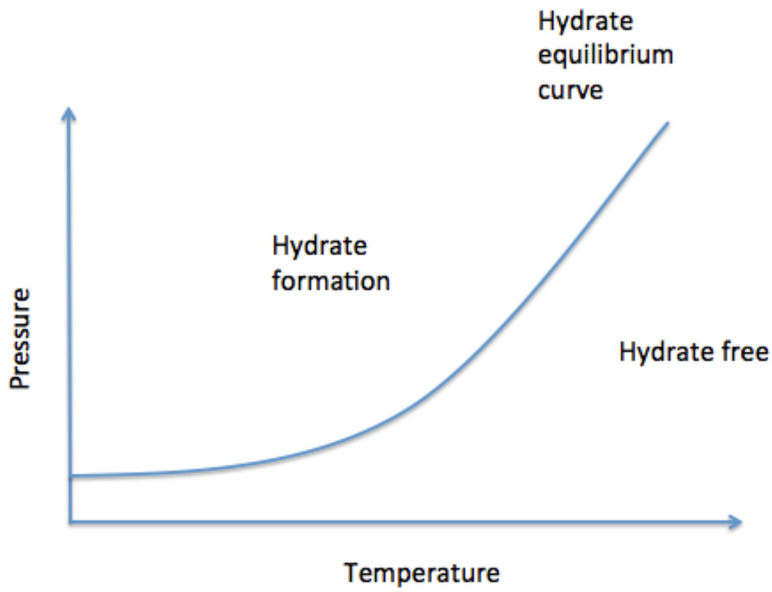

Figure 4.3. Hydrate equilibrium curve.

The hydrate curve showing in figure 4.3 indicates how the pressure and temperature will affect the possibilities for hydrate formation. The hydrate curve is an individual curve for each well and template, and needs to be updated as often as the producing content is changing, meaning the changes of the water and HC composition. Under stable production the well stream needs to be on the right side of the hydrate curve to avoid any hydrate formation.

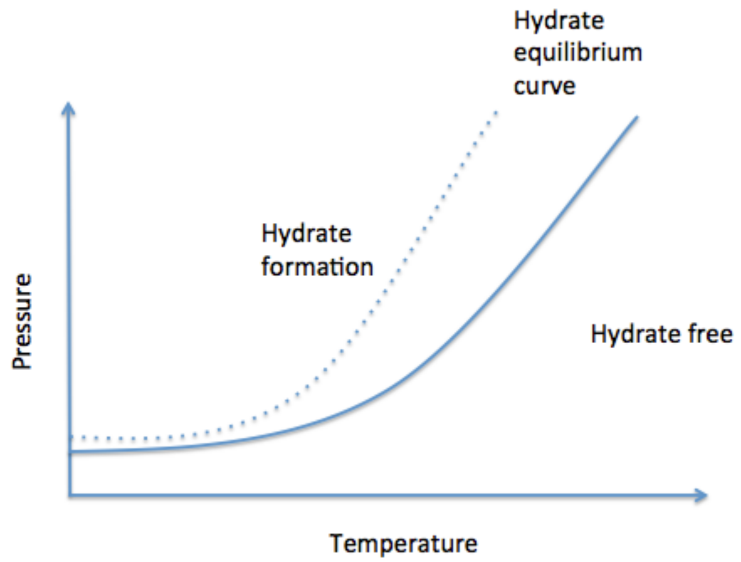

Figure 4.4 Manipulated hydrate equilibrium curve with chemicals.

Depending on the situation it is possible to manipulate the hydrate equilibrium curve by using chemicals showing in figure 4.4. The dotted line shows the new manipulated hydrate equilibrium curve. By injecting anti freezing chemicals like methanol, ethanol or glycol on the wellhead, the hydrate curve for the well stream will change. Gullfaks A can provide methanol injection when desired. The anti freezing needs to be mixed with the water in the well stream, when these two are mixing the freezing/hydrate point will be reduced to a lower temperature. Continuous chemical injection is done on some fields with long flowline distance, this is done with reservoir containing gas and very small amounts of water, e.g. Statoil`s gas field at Melkøya, Snøhvit. The flowline can also be inhibited with anti freeze for a planed shutdown avoiding hydrate formation in the flowline.

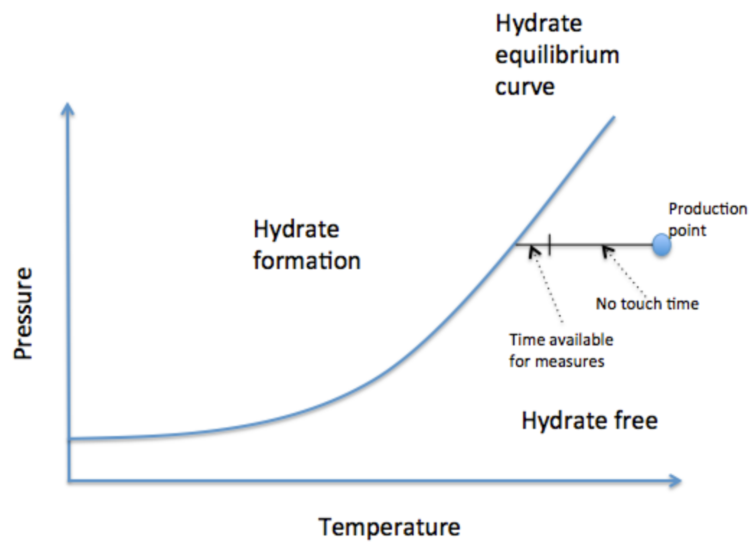

Figure 4.5. No touch time

Another important aspect is when an unplanned shutdown of the flowline happens. This results in that the fluid will stagnant in the flowline. When it is stagnant it will be cooled down by the surroundings, and at a given time it will move into the hydrate formation area. Unplanned flowline shutdowns happen for different reasons, some of them are short but some may last longer. The “no touch time” showing in figure 4.5 indicates the time from the production stops till the fluid has been cooled down to reaching the dangerous hydrate formation point of the curve. If the production is ready to be started up again within this time, no measures are needed. Therefor the term “no touch time” has come. If the no touch time has exceeded and the production still is not ready to start, measures are needed to avoid hydrate formation. If heated flowlines is no option, depletion may be the only solution for avoiding hydrates. Depletion of a flowline will be done topside on a platform to the flare system on the top of the riser, or/and at the X-mas tree with use of the service line. Water depth of the location must be accounted for due to the static pressure of the fluid, if it is deep enough pressure depletion alone wont get the fluid out of the hydrate formation zone. The water depth of the GSO development is 134 m, which is in worst case 13,4 bar if water column. This pressure should be lower than the required hydrate formation pressure. Anti freeze chemical injection at subsea wellhead together with topside depletion to mix in the anti freezing along the whole flowline could be an alternative for deeper developments.

Under normal production the design of the flowline and the related subsea production system must be that it is operating outside the hydrate formation zone. For different reasons it is most likely that in given situations the flowlines will be operating in the hydrate zone from time to time. Therefor it is necessary to understand the challenges with hydrates and what measures could be done for allowing operating in this zone and how to get out of the hydrate zone in a safe matter. First of all it is necessary to know the reservoir content, which fluids are to be produced and the composition of it. The environmental conditions where the equipment shall stand will also have a great contribution for the design. From here it is possible to design the equipment.

The flowline`s insulation in relation to its surroundings is important for the heat transfer between the well stream and the surroundings. As seen in figure 4.3 the temperature of the well stream is essential to keep over the hydrate formation zone if the other three conditions for hydrate formation are present. Heat transfer can happen in three different methods [6: 92]:

- Conduction is heat led through a material.
- Convection is heat led between fluids (liquid and gases).
- Radiation is heat emitted by electromagnetic waves

Together these three heat transfer methods can be composed to an overall heat transfer coefficient U. The overall heat transfer coefficient U is a measurement of how well a pipeline is insulated, or how much heat is let out. The constant U will have the notation: $\frac{w}{m^2 \cdot °C}$.

The heat transfer between two states or object, are denoted Q or heat transfer per time, $\dot{Q}$. The first law of thermodynamics is simply an expression of the conservation of energy principle, "the change of energy content of a body or any other system is equal to the difference between the energy input and the energy output." [6: 2] Which means that the energy loss, heat loss, of a fluid inside a pipeline needs to be equal to the gained energy in the surrounding. To find the heat loss in the well stream, we need to find the evolution of the fluid temperature as a function of the distance from the wellhead. To find the evolution we need to consider the temperature change of the pipeline length x and x+dx.

First lets define the energy of the well stream fluid Q_{fluid} and the energy of the surroundings Q_{sea}.

$$Q_{fluid} = \dot{m} \cdot C_p \cdot \Delta T \tag{4.1}$$

$$Q_{fluid} = \dot{m} \cdot C_p \cdot T[(x + dx) - x] \tag{4.2}$$

$$Q_{sea} = U \cdot A \cdot [T(x) - T_{sea}] \tag{4.3}$$

Where A = the area in contact between the fluid and the surroundings, $A = \pi D dx$, and:

$\dot{m}$	=	Mass flow per second	$\left[\frac{kg}{s}\right]$
C_p	=	Specific heat capacity	$\left[\frac{J}{Kg \cdot °C}\right]$
ΔT	=	Temperature difference	[°C]
U	=	Heat transfer constant	$\left[\frac{W}{m^2 \cdot °C}\right]$
A	=	Area	$[m^2]$
$T(x)$	=	Temperature in desired point	[°C]
T_{sea}	=	Sea temperature	[°C]

Newton`s law of cooling states that: "The rate of change of the temperature of an object is proportional between its own temperature and the ambient temperature (sea temperature in this case)."

The instance change is mathematically given by the derivative:

$$\frac{dT}{dx} = -k \cdot (T - T_{sea}) \tag{4.4}$$

Where “k” is a positive heat constant that must be determined. The negative sign is due to the temperature shall be decreasing.

By equalizing equation 4.2 and 4.3 we will get $Q_{out} = Q_{in}$

$$Q_{fluid} = Q_{sea}$$

$$\dot{m} \cdot C_p \cdot T[(x + dx) - x] = U \cdot A \cdot [T(x) - T_{sea}]$$

We can see that several of the parts of the equation are not depended on the distance and we will use these as the constant k. By re-arranging we get

$$k = \frac{U \cdot D \cdot \pi}{\dot{m} \cdot C_p}$$

The constant k is determined and we can now apply this to the Newton`s law of cooling, eq. 4.4.

$$\frac{dT}{dx} = -k \cdot (T - T_{sea})$$

We start by separating the variables.

$$\frac{1}{(T - T_{sea})} dT = -k \cdot dx$$

Then integrate

$$\int \frac{1}{(T - T_{sea})} dT = \int -k \cdot dx$$

$$Ln|T - T_{sea}| = -kx + C1$$

Since we know or assuming that the temperature T is warmer than the surroundings T_{sea} we remove the absolute value.

$$T - T_{sea} = e^{-kx + C1}$$

Then the general solution will be

$$T(x) = C \cdot e^{-kx} + T_{sea}$$

To determine the constant C we use the start conditions $T(0)=T_{in.}$

$$T(0) \Longrightarrow T_{in} = Ce^{-k0} + T_{sea}$$

$$C = T_{in} - T_{sea}$$

Thus

$$T(x) = (T_{in} - T_{sea}) \cdot e^{-kx} + T_{sea} \qquad 4.5$$

By applying equation 4.5 together with some assumptions, the well stream fluid temperature is found after the heat loss in the well stream fluid to the surrounding. Doing this it is possible to see where the well stream is in the hydrate formation zone chart.

If the analysis of the fluid temperature in the flowline is too low that it risks ending inside the hydrate formation zone it is possible to provide heat to the flowline. Continuous heating is a calculation that must be considered if that is the best option, better and more insulation may be a reasonable choice. A more likely situation is if an unexpected shutdown happens, the well stream flows stops and it will start cooling down by the surroundings and most likely ending inside the hydrate formation zone. To avoid this to happen or bring the well stream out of the hydrate zone again before start-up, a heated flowline could be the only alternative.

4.1.3 Flowline heating method

Direct Electrical Heating (DEH) is the chosen solution for heating the new flowlines for the GSO development. The DEH system is design so that the flowline itself will be one electrical conductor, therefor the pipe must be electrically conductive with a resistance that creates heat.

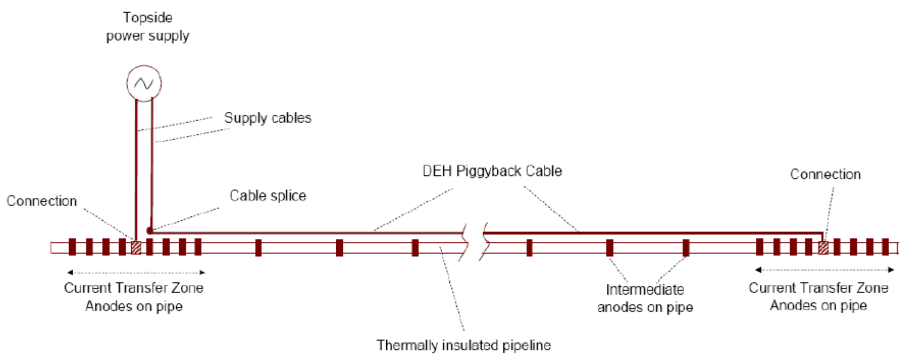

Figure 4.6 Design principle of a DEH system [25].

Figure 4.6 above shows the principle of a DEH system, a piggyback mounted electrical cable is attached to the pipeline all the way to the end of the pipeline. AC-power is supplied from topside. At the end there will be an electrically connection point to the pipeline that lets the pipeline lead the current back, a new connection point at the pipeline lets the current back topside, ending the loop. A magnetic field is generated around the pipeline due to AC-current and the two conductors. There will be differences in electrical properties between the two conductors (the DEH cable and the flowline), therefor it is designed with an open loop for safety reasons such that some of the current will be directed through the water on the return-way. Extra anodes create a galvanic connecting between the water to the pipeline in the connection points (grounding). Several anodes along the pipeline keep the current transfer back through the sea along with the pipe [26]. According to a master thesis [27] 70% of the generated heat is due to the pipeline resistivity, 20% by the DEH cable and 10% is in the seawater due to the magnetic field. The extra anodes attached to pipe will also compensate for any increase in corrosion due to the AC-current [28]. The efficiency of a DEH system is around 70% according to term paper at NTNU [29].

4.1.4 Water

Water is one of the conditions that need to be present for hydrate formation. Mixing chemicals into the water in the well stream is possible to manipulate the waters initially properties. Chemical injection can be done continuous or periodically if necessary. Since the chemicals have to react with the water in the stream it is not convenient to inject anywhere. The injection points should be up-stream a choke to assure best possible blending, even doing this it is not possible knowing that the chemicals have reacted completely with the water. This may lead to overdosing of chemicals, which can lead to new challenges. Typical chemicals for hydrate challenges are ethanol, methanol and glycol and these are needed in large quantities. The chemicals will be stored on the topside facilities and must be handled by personnel, which will be a potential threat due to toxic and explosive properties. The sales products will also be affected of these chemicals, ethanol and methanol will in addition to the water, mix with the gas phase giving a poorer quality of the gas. Chemicals can also interrupt the process regulating, giving false readings of level switches due to changed density of the fluids when saturated of chemicals.

Subsea separators can remove the producing water before it will give flow assurance issues. A subsea separator is quit similar to a topside separator, with the purpose to separate out the water. Subsea processing will be a bit harder than topside due to the remoteness if anything should need adjustment or maintenance, but it is possible if simple and robust solutions are chosen. According to OG21 the most challenging with subsea process is equipment is getting larger and larger for vessels to manage and it is getting more power consuming. The produced water that is separated out cannot be directly diluted out to sea due to it may contain too much oil residues, Norwegian government has set the limit for oil dilute of 30 mg/litre [30]. Therefor the water must either be injected back into a suitable reservoir, which will require high-pressure injection pumps. Or a separate flowline with booster pumps for the produced water to be further handled topside. If the water were removed from the flowline containing HC, the flow assurance challenges would be significant smaller.

4.1.5 Erosion

Erosion is defined as removal of a solid surface by the repeated application of mechanical forces [31]. A fluid flowing through a pipe will give continuous repeated mechanical forces on the pipes inside surface. These forces are strongly depended on the fluid properties, the fluid velocity and the shape of the pipe. Erosion will threaten the pipes integrity by changing the initial dimensions of the pipe, i.e. the wall thickness. In worst-case scenarios erosion have eroded holes directly through the pipe causing leakages. Erosion is impossible to discover only looking at it due to the material is eaten up from the inside, therefor erosion assessments should be done under dimensioning. Extended inspection programs should be applied if erosion concerns are increasing. Intelligent pigs are suitable for inspecting subsea pipelines and flowlines, these are equipped with sensors that can measure the thickness 360 degrees of the whole flowline length.

ISO 13703 and NORSOK P-001 standards are referring to an empirical formula for multi-phase stream maximum velocity with respect to erosion. It is important to note that this formula does not take into account solid production or any other corrosive fluids like CO_2 and H_2S. More advanced simulation programs should be used to check for including solids. However this empirical formula can be used if there is no information of the fluids erosive/corrosive properties are available.

$$v_e = \frac{c}{\sqrt{\rho}} \tag{4.6}$$

Where:

v_e	=	Fluids erosional velocity	$\left[\frac{m}{s}\right]$
c	=	Empirical constant	$[Dimensionless\ constant]$
ρ	=	Fluids density	$\left[\frac{kg}{m^3}\right]$

The fluids erosional velocity is the velocity where erosion may start due to the fluid`s forces on the wall. Therefor the fluids velocity "v" must be $< v_e$. Even though the constant "c" is given as dimensionless, it is needed to have some units for the equation giving answers v_e in m/s.

Industry experience and testing indicates the empirical constant "c" should be 122 for steel pipes. If corrosion resistant alloys are used the constant can be used as 180.

4.1.6 Corrosion

Corrosion in a pipeline can be separated into two categories, internal and external corrosion. There are many types of corrosion, but only some will be highlighted here.

The internal corrosion is depended on fluids corrosive properties that react with the transporting material. CO_2 and H_2S gases can be corrosive on steel, corrosion resistant alloys are a measure to avoid internal corrosion. It is also possible to lay internal coating inside a pipe, the disadvantage with coating is that it is vulnerable to erosion. If parts of the coating are eroded off, the remaining steel is exposed for corrosion.

The external corrosion of a pipe is how the pipe material reacts with the surroundings, stainless steel like the 13%Cr has good resistance against CO_2, but will still corrode some in seawater. Therefor cathodic protection is still needed even though it is defined as stainless. Cathodic protection is done by attach a more active alloy on the material which wanted to protect. The alloy with the higher electro potential will corrode instead of the pipeline. The cathodic protection can be seen on as a controlled corrosion. A challenge with cathodic protection is that some H^+-ions will be released from the reaction with seawater.

HISC

Hydrogen Induced Stress Cracking also known as hydrogen embrittlement is an incident where hydrogen ions diffuses into the steel, changing the initial properties of the steel e.g. the yield strength. Conditions for HISC to occur:

- Local stress and strain.
- Available H^+ ions.
- Microstructures where hydrogen can diffuse.

Other factors that may increase the HISC availability:

- Cathodic protection potential.
- Surface temperature.
- Water depth/hydrostatic pressure.
- Load
- Type of material

Hydrogen is the smallest sized atom in the periodic table, the hydrogen can diffuse into the steel and make invisible cracks. It will diffuse into the steel where it is already small microscopic cracks, which will change the initial properties for the steel. The steel will lose its initial strength and could yield or fracture before original maximum load is reached. It does not exist any non-destructive tests (NDT) that can discover HISC, specimen needs to be analyses to discover possible HISC. Due to the change of material strength and “impossible” to monitor potential HISC it is important to design the system for potential HISC [32].

The common features of corrosion are that it has a direct influence on the initial properties and the material will not perform its functional requirements if affected by severe corrosion.

4.1.7 Wax

Some reservoir liquids consist of heavy weight molecular HC, C_{18}-C_{60} parafines. These can be seen on as wax-molecules, which again can form to wax particles. When the reservoir fluids is producing the well stream will decline some in pressure and temperature, during this decline the lighter HC molecules can separate itself from the heavier components. The lighter HC-molecules will act as a solvent for the wax-molecules. By reducing the temperature further down the well stream will reach the wax-appearance-temperature, (WAT). At this point/temperature, given the specific HC chemistry content and pressure, the wax molecules will start transforming to wax particles. The particles will start to grow on the pipe wall where it is coldest, creating a more rough pipe surface that will lead to a greater pressure drop that could result in more wax precipitation. Wax can block entire pipelines, leading to production stop. In that way wax is somewhat similar to hydrate formation, depending on fluid temperature and plugging pipelines. Besides temperature control, the wax can be avoided with solvent chemicals and dispersants. This entails continuous injection in the well stream with the following dis-advantages as costs, chemical storage, environment and potential hazard with spill. Wax can also be handled by mechanical removal with a pig. This allows for some wax build-up, but the pig will clean and scrape the wax away from the pipe walls. The period of pigging will vary from situation to situation, how fast the wax is accumulating, it can be several times per week or once per every third month. Wax tends to get harder over time, and the pig can in worst case scenarios get stuck. Typical wax appearance temperature of North Sea oil and condensate are in the range of 30-40°C [22]. Well fluid samples of the existing development shows that wax-molecules are present in the reservoir [2], this must be accounted for under design and production.

The theory presented and formula derived with respect to flow assurance will now be applied on the GSO development. I will analyse the suitability of the development and which challenges that needs measures, and how to solve or avoid the flow assurance challenges.

4.2 Slugs GSO analysis

Seabed surveys of the GSO development, from templates to the Gullfaks A platform shows that the seabed is quite flat which means that the flowline can be laid without regards to hills and valleys, both locations are on a water depth at 134 m. Terrain slugs will not be a challenge for the GSO development, the flowline layout does not need to include the terrains slug concern.

To check for hydrodynamic slugs, it is necessary to see the whole field production time. The well stream will change over time, the Statoil`s reservoir engineers has estimated the production profile ref. table 2.1. From these production profiles it is possible to check how the Reynolds number is changing over time, due to the well stream changes. The Reynolds number is given from equation 3.5:

$$Re = \frac{ID \cdot v}{\upsilon} \qquad 3.5$$

Where the velocity and the kinematic viscosity is changing over time.
Based on the production profile table a new table for the Reynolds number is generated.

Assumptions:

- The ideal gas law is applicable.
- Water and oil is incompressible.
- Kinematic viscosity for oil - $23 \cdot 10^{-6} \frac{m^2}{s}$.
- Kinematic viscosity for gas – $0{,}16 \cdot 10^{-6} \frac{m^2}{s}$.
- Kinematic viscosity for water – $0{,}32 \cdot 10^{-6} \frac{m^2}{s}$.
- Production pressure and temperature is assumed.

Table 4.1 Reynolds number

Initial conditions			8" 8000m flowline	6" 2200m flowline
Production Year	Production pressure in bar	Production temperature in °C	Re	Re
1	180	80	5849	7620
2	185	85	166056	216313
3	190	90	642471	836917
4	185	89	866676	1128979
5	180	88	1454513	1894726
6	175	87	1739139	2265496
7	170	86	2092660	2726011
8	165	85	2454436	3197280
9	160	84	2890213	3764947
10	155	83	3341459	4352764
11	150	82	3860440	5028816
12	145	81	4297935	5598721
13	140	80	4753333	6191947
14	135	79	5132230	6685518
15	130	78	2745492	3576425
16	125	77	3426745	4463861
17	120	76	2490662	3244471
18	115	75	2132324	2777679
19	110	74	1634730	2129487

Table 4.1 is generated based on the variation in the production profile. The Reynolds number is during the whole production profile above the laminar flow regime at Re<2300 which means that there will be a turbulent flow. Under stable and steady production, hydrodynamic slugs will not occur. However under a production stop, the well stream will be separated into different phases in the flowline if not flowing. Hydrodynamic slugs could occur under start-up and should be taken into account for start-up preparations.

The GSO development is tying-in to an already existing flowline and thereby an existing riser as well, an active choke would need flow and pressure gauges along the whole riser. The existing riser is not prepared for these gauges and would be quite complicated and costly to install afterwards. The water depth at Gullfaks A is 134m and the total height from seabed to the inlet separator is approximately 175m. With the 8" flowline and riser the liquid column would contain in worst-case scenarios:

$$\frac{\pi \cdot (0{,}1971m)^2}{4} \cdot 175m = 5{,}3m^3$$

4.3 Hydrates and wax GSO analysis

Both hydrates and wax are depended on the well stream temperature. This chapter will focus on the temperature evolution along the producing flowline and the cool down effect of a shut in still standing well fluid. The two different production flowlines are calculated, the 8" from O-template till the platform and the 6" from O-template till the G-template where the well stream from O will blend with other production wells. The calculations are based on that all the complete production from O-template is flowing trough the respective flowline.

By looking at the conditions we have with some assumptions made, the well stream will be in a hydrate area formation if temperature is low enough. The temperature drop through the flowline needs to be analysed and checked. Earlier assumptions are still valid, but new ones are needed.
Assumptions:

- Specific heat capacity gas: 2,25$\frac{kJ}{Kg\cdot°C}$
- Specific heat capacity oil: 2,00$\frac{kJ}{Kg\cdot°C}$
- Specific heat capacity water: 4,20$\frac{kJ}{Kg\cdot°C}$
- Flowlines insulation constant: 5$\frac{W}{m^2\cdot°C}$
- Ambient temperature is constant and colder than the well stream
- Ambient sea water temperature is 7°C
- Water is incompressible with density 1000$\frac{kg}{m^3}$
- Oil is incompressible with density 825$\frac{kg}{m^3}$
- Ideal gas law is applicable, gas density 0,8$\frac{kg}{m^3}$
- 8" flowline length is 8km=8000m
- 8" flowline ID = 0,1971m
- 6" flowline length is 2,2km=2200m
- 6"flowline ID = 0,1513m
- All wells are producing as production profile indicates.

Remember the constant "k" has among the two terms $\dot{m}$ in kg/s and C_p, the mass flow is found by combining the flow per second of each phase with their respective density. The composed specific heat capacity is found by combining the percentage of each fluid with the respective specific heat capacity of the fluid.

By applying equation 4.5 derived from Newton's law of cooling the following table is generated.

$$T(x) = (T_{in} - T_{sea}) \cdot e^{-kx} + T_{sea} \tag{4.5}$$

I will demonstrate the outcome of the constant "k" to show that the remaining unit of formula 4.5 is temperature in Celsius.

$$k = \frac{U \cdot D \cdot \pi}{\dot{m} \cdot C_p} = \frac{J \cdot m^2 \cdot 1 \cdot s \cdot kg \cdot ℃}{s \cdot m^2 \cdot ℃ \cdot kg \cdot J} = 1$$

Table 4.2 Arrival temperatur 8" flowline

8" flowline 8000m						
Production Year	Production temperature ℃	Mass flow $\dot{m}$ in kg/s	Cp in $\frac{kJ}{kg \cdot ℃}$	k	Arrival temperature at platform in ℃	Temperature loss in ℃
1	80	2,12	2,178	0,671	7	73
2	85	21,42	2,229	0,065	53	32
3	90	53,14	2,271	0,026	75	15
4	89	51,50	2,259	0,027	73	16
5	88	59,48	2,257	0,023	74	14
6	87	56,83	2,253	0,024	73	14
7	86	54,24	2,250	0,025	71	15
8	85	52,32	2,249	0,026	70	15
9	84	50,70	2,249	0,027	69	15
10	83	49,48	2,249	0,028	68	15
11	82	48,45	2,250	0,028	67	15
12	81	47,76	2,250	0,029	66	15
13	80	47,10	2,250	0,029	65	15
14	79	46,35	2,250	0,030	64	15
15	78	25,48	2,252	0,054	53	25
16	77	25,61	2,252	0,054	53	24
17	76	17,99	2,254	0,076	44	32
18	75	11,69	2,255	0,117	34	41
19	74	7,25	2,254	0,190	22	52

We can see that the mass flow will have a large contribution of the cool down effect along the flowline. The higher the mass flow is the higher the energy level of the fluid will be along the flowline, which will take longer time to cool down. Year 1, 18 and 19 are most sensitive to temperature drop through the 8" flowline. These temperatures can give flow assurance challenges with respect to wax and hydrates.

Changing the insulation of the flowline, we can compare the effect by seeing the difference in arrival temperature. The following table is for the 8" flowline

Table 4.3 Arrival temperature insulation class

Production year	Arrival temp. U=4 in °C	Arrival temp. U=5 in °C	Arrival temp. U=6 in °C
1	8	7	7
2	58	53	49
3	77	75	72
4	76	73	71
5	77	74	72
6	76	73	70
7	74	71	69
8	73	70	68
9	72	69	66
10	71	68	65
11	70	67	64
12	69	66	63
13	68	65	62
14	67	64	61
15	57	53	49
16	57	53	49
17	49	44	40
18	39	34	29
19	27	22	18

Figure 4.7 shows the temperature evolution for the production lifetime for different insulation classes on the 8” flowline. All other properties are constant. The insulation class will have a great contribution for the heat transfer, but to have any positive effect for this field specific case it is likely that the heat transfer constant U must be even lower than 3.

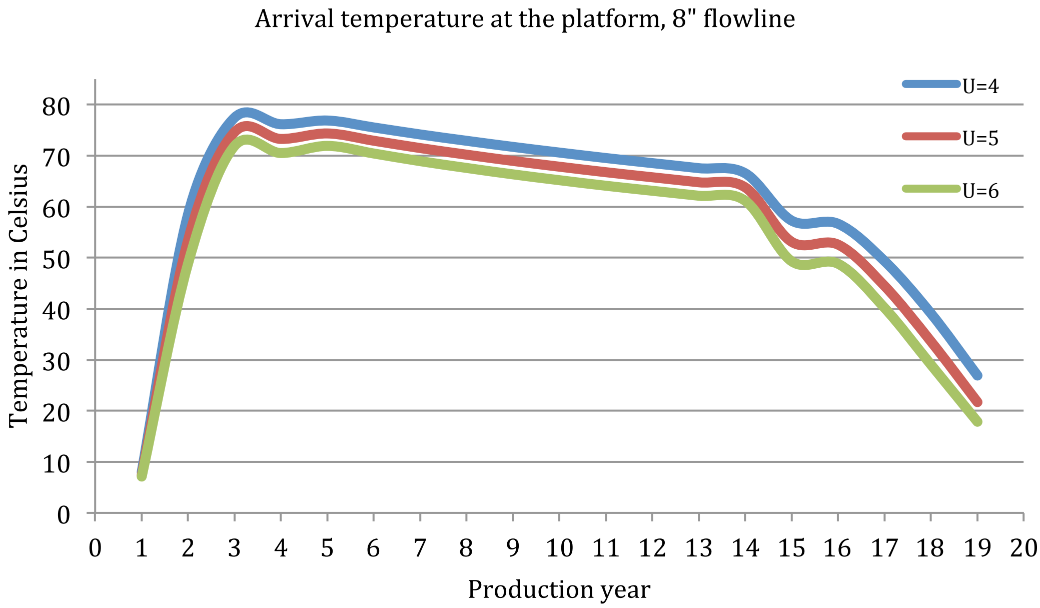

Figure 4.7 Arrival temperature

Figure 4.8 and 4.9 shows the evolution of the temperature loss over the distance at 8km in year 11 and 19 with the 8” flowline

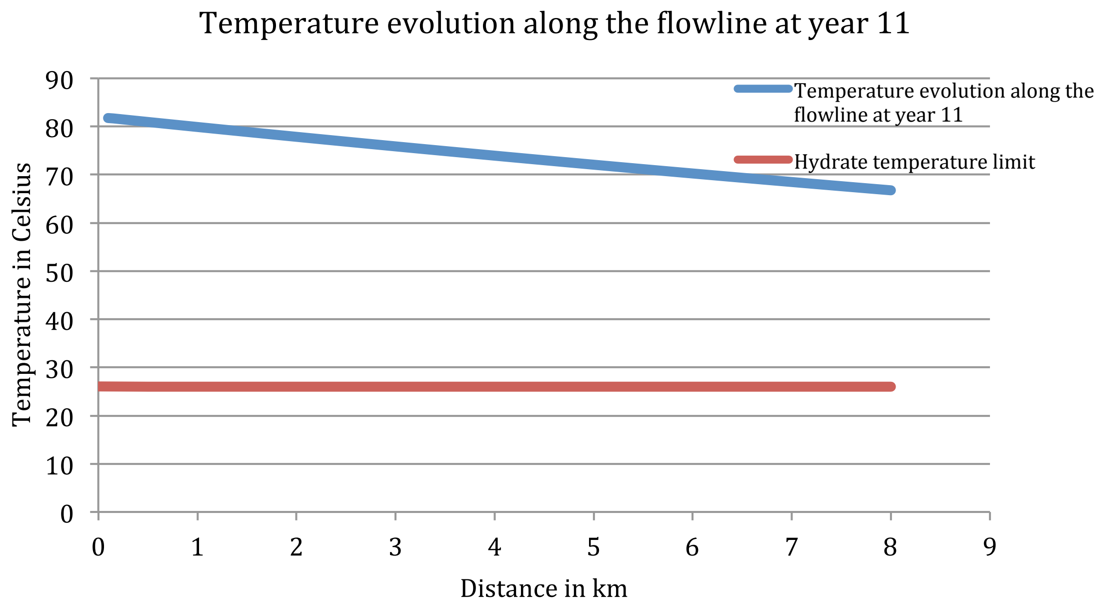

Figure 4.8 Temperature evolution year 19

The temperature is above the hydrate curve the whole flowline length with a good margin for year 11.

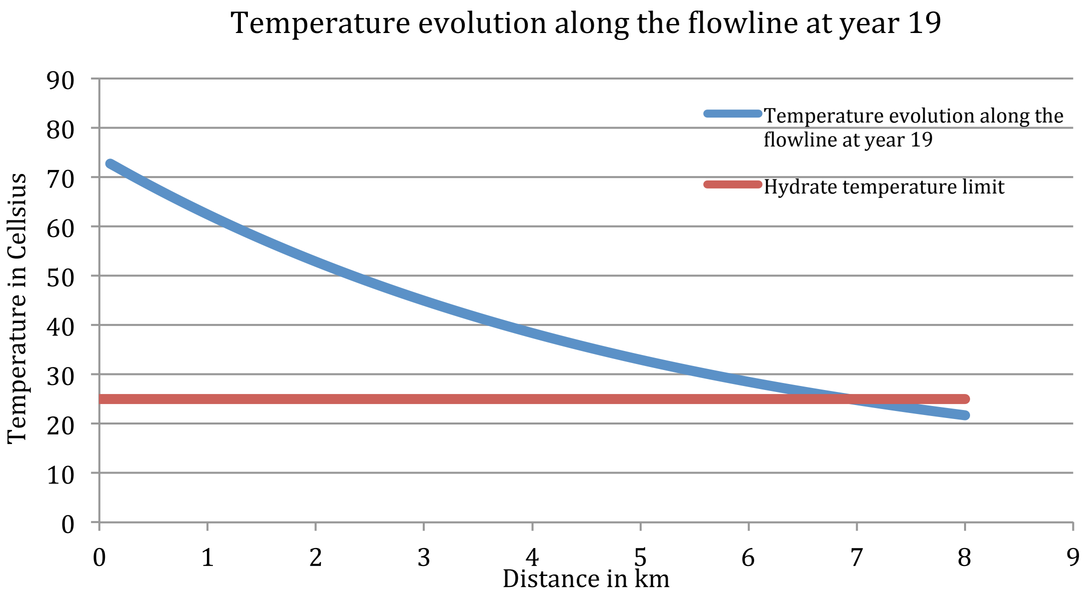

Figure 4.9

The temperature evolution along the flowline at year 19 will have a hydrate challenge. Figure 4.9 shows the flowline temperature will enter the hydrate temperature limit after approximately 6 km, the temperature will drop further down from the 6 km and to platform arrival.

Table 4.4 shows the 6” flowline from O-template to G-template with an insulation U=5. The calculation are done up to G-template due to the uncertainties of the blend in with other production wells in the flowline.

Table 4.4 Arrival temperature 6” flowline

6" flowline 2200m						
Production Year	Production temperature °C	Mass flow $\dot{m}$ in kg/s	Cp	k	Arrival temperature at template G in °C	Temperature loss in °C
Year 1	80	2,12	2,178	0,515	31	49
Year 2	85	21,42	2,229	0,050	77	8
Year 3	90	53,14	2,271	0,020	86	4
Year 4	89	51,50	2,259	0,020	85	4
Year 5	88	59,48	2,257	0,018	85	3
Year 6	87	56,83	2,253	0,019	84	3
Year 7	86	54,24	2,250	0,019	83	3
Year 8	85	52,32	2,249	0,020	82	3
Year 9	84	50,70	2,249	0,021	81	3
Year 10	83	49,48	2,249	0,021	80	3
Year 11	82	48,45	2,250	0,022	78	4
Year 12	81	47,76	2,250	0,022	77	4
Year 13	80	47,10	2,250	0,022	76	4
Year 14	79	46,35	2,250	0,023	75	4
Year 15	78	25,48	2,252	0,041	72	6
Year 16	77	25,61	2,252	0,041	71	6
Year 17	76	17,99	2,254	0,059	68	8
Year 18	75	11,69	2,255	0,090	63	12
Year 19	74	7,25	2,254	0,146	56	18

The temperature evolution along the flowlines are strongly depended on the mass flow and velocity through the flowline. The faster the well stream flows, the less time the ambient temperature gets to cool down the well stream and the more mass it contains the more energy is to be cooled down.

The 8” flowline will have a large temperature drop at year one of production, the well stream is completely cooled down to the ambient temperature. At production year 18 the platform arrival temperature is entering the wax appearance temperature, and at year 19 the arrival temperature is entering for the hydrate appearance temperature after 6 km along the flowline.

The 6” flowline will produce in the wax appearance temperature at year one of production, otherwise the production temperatures are above both wax- and hydrate appearance temperatures. It is necessary to pinpoint that there are in these calculations no information of what conditions the well stream will meet at G-template and thereafter the F-template. The F- and G-template production need to be taken into account for further calculation before any conclusion can be made regarding platform arrival temperature.

4.3.1 No touch time

If the well stream experiences an unplanned shutdown for different reasons, the well stream will be trapped inside the flowline and immediately starts to cool down due to the ambient sea temperature. Depending on the content of the well stream, the no touch time must be known for the operator that controls the well stream. From shutdown and during the no touch time, no measures are needed to start up again. If the shut down exceeds the no touch time, measures are needed to avoid getting into the hydrate formation zone. Since there is no flow through the flowline, the cool down will act similar and constant over the whole flowline. It is necessary to include that the flowing well stream has already been cooled down during the production before a possible shutdown, and the coldest temperature should be considered. The coldest temperature will be closest to the arrival point, furthest away from the well.

The heat transfer effect is given from equation 4.7

$$\dot{Q} = U \cdot A \cdot \Delta T \qquad 4.7$$

Where

$\dot{Q}$	=	Heat transfer rate	$\left[w = \frac{J}{s}\right]$
U	=	Heat transfer constant	$\left[\frac{w}{m^2 \cdot °C}\right]$
A	=	Area of heat transfer	$[m2]$
ΔT	=	Temperature change	[°C]

To find stored heat in the well fluid we apply equation 4.8

$$Q = C_P \cdot m \cdot \Delta T \qquad 4.8$$

Where:

Q	=	Heat	$[J]$
C_P	=	Specific heat capacity	$\left[\frac{J}{kg \cdot °C}\right]$
m	=	Fluid mass	$[kg]$

Combining equation 4.7 and 4.8 the time for heat transfer is found which is the NTT, equation 4.9.

$$\frac{Q}{\dot{Q}} = time\ in\ second \qquad 4.9$$

Assuming the hydrate formation with operational pressure is starting at 20°C, the time for measures must start at some point before the well stream temperature is reaching this point. Assuming the time it takes for cooling from 35°C-20°C is sufficient for measures, the "No touch time" will be the time from flowline arrival temperature cools down to 35°C.

Assumptions:

- Specific heat capacity gas: $2{,}25\frac{kJ}{Kg\cdot°C}$
- Specific heat capacity oil: $2{,}00\frac{kJ}{Kg\cdot°C}$
- Specific heat capacity water: $4{,}20\frac{kJ}{Kg\cdot°C}$
- Flowlines insulation constant: $5\frac{w}{m^2\cdot°C}$
- Ambient temperature is constant and colder than the well stream
- Ambient sea water temperature is 7°C
- Water is incompressible with density $1000\frac{kg}{m^3}$
- Oil is incompressible with density $825\frac{kg}{m^3}$
- Ideal gas law is applicable, gas density $0{,}8\frac{kg}{m^3}$
- End of No touch time starts at 35°C
- 8" Flowline OD is 0,2191m and ID is 0,2171m
- 6" Flowline OD is 0,1683m and ID is 0,1513m

Table 4.5 No touch time 8” flowline

8" flowline 8000m								
Production Year	Composed Cp in $\frac{kJ}{kg{\cdot}°C}$	Composed density in $\frac{kg}{m^3}$	Mass per unit meter in kg	NTT ΔT in °C	Q in J	$\dot{Q}$ in w	NTT sec	NTT in hrs and min
1	2,178	332,27	10,14	0	0	0	0	0min
2	2,229	232,25	7,09	18	290920	63	4589	1h 16 min
3	2,271	213,82	6,52	40	586869	136	4306	1h 12 min
4	2,259	189,02	5,77	38	498751	132	3786	1h 3 min
5	2,257	168,66	5,15	39	457058	135	3375	56 min
6	2,253	156,28	4,77	38	407391	131	3121	52 min
7	2,250	145,24	4,43	36	363871	126	2897	48 min
8	2,249	136,70	4,17	35	330187	121	2726	45 min
9	2,249	129,19	3,94	34	301159	117	2576	43 min
10	2,249	122,78	3,75	33	276715	113	2449	41 min
11	2,250	117,01	3,57	32	255113	109	2334	39 min
12	2,250	112,13	3,42	31	236831	106	2237	37 min
13	2,250	107,51	3,28	30	219825	103	2144	36 min
14	2,250	103,51	3,16	29	204532	99	2065	34 min
15	2,252	102,08	3,11	18	126978	62	2038	34 min
16	2,252	96,18	2,93	18	116085	60	1920	32 min
17	2,254	93,88	2,86	9	61122	33	1876	31 min
18	2,255	87,86	2,68	0	0	0	0	0 min
19	2,254	82,04	2,50	0	0	0	0	0 min

Table 4.6 No touch time 6" flowline

6" flowline 2200m								
Production Year	Composed Cp in $\frac{kJ}{kg{\cdot}℃}$	Composed density in $\frac{kg}{m^3}$	Mass per unit meter in kg	NTT ΔT in ℃	Q in J	$\dot{Q}$ in w	NTT sec	NTT In min
1	2,178	332,27	5,97	0	0	0	0	0 min
2	2,229	232,25	4,18	42	389979	111	3520	59 min
3	2,271	213,82	3,84	51	449551	136	3303	55 min
4	2,259	189,02	3,40	50	386938	133	2904	48 min
5	2,257	168,66	3,03	50	341541	132	2589	43 min
6	2,253	156,28	2,81	49	308870	129	2394	40 min
7	2,250	145,24	2,61	48	280211	126	2223	37 min
8	2,249	136,70	2,46	47	257661	123	2091	35 min
9	2,249	129,19	2,32	46	237963	120	1976	33 min
10	2,249	122,78	2,21	45	221031	118	1878	31 min
11	2,250	117,01	2,10	43	205853	115	1791	30 min
12	2,250	112,13	2,02	42	192711	112	1716	29 min
13	2,250	107,51	1,93	41	180416	110	1645	27 min
14	2,250	103,51	1,86	40	169516	107	1584	26 min
15	2,252	102,08	1,84	37	152135	97	1563	26 min
16	2,252	96,18	1,73	36	139951	95	1473	25 min
17	2,254	93,88	1,69	33	124236	86	1439	24 min
18	2,255	87,86	1,58	28	98926	73	1348	22 min
19	2,254	82,04	1,47	21	68629	55	1258	21 min

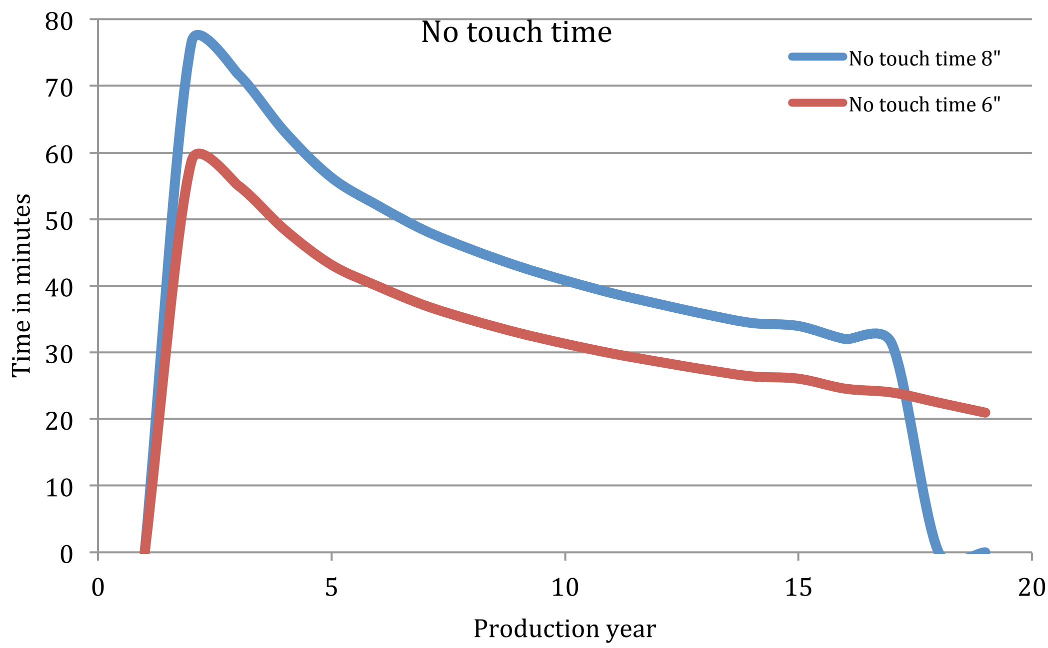

Figure 4.10 No touch time for 6" and 8" flowline

The no touch time is based on the assumed no touch time temperature at 35°C and the heat rate constant U=5. For the 8” flowline the NTT varies from the shortest at 0min till the longest at 1h and 16min. For the 6” flowline the NTT varies from 0min till 59min. Both the 6” and 8” flowline have quite short NTT, and measures are needed to avoid hydrates at an early time, or measures to get out of the hydrate formation before start-up should be considered.

4.3.2 Flowline heating

The main tool to avoid hydrates and wax in the GSO flowlines is to apply heat to the well stream when needed. By applying heat to the flowlines the no touch time can be extended to “infinity”, and the temperature challenges at the beginning and the end of the production profile can be handled ref table 4.2 for the 8” and table 4.4 for the 6” flowline. The new flowlines, the 8” from O-template to towhead and 6” will be installed with DEH cables. From the towhead to the platform and from G-template to the platform the existing flowlines are already heated by bundle-heating when needed. Therefor the DEH cable need to heat the 8” at 6200m and the 6” at 2200m.

Assumptions:

- DEH has an efficiency η_{DEH} = 70% = 0,7
- DEH should heat from ambient temperature at 7°C to above wax- and hydrate appearance temperature at 40°C in 6 hours.
- DEH should maintain the temperature in the flowlines, should handle a temperature variation for 2°C in 10 min.
- 8”flowline is 6200m.
- 6” flowline is 2200m.

Finding the heat needed:

$$Q = C_P \cdot m \cdot \Delta T \qquad 4.8$$

Include the desired time for the heat transfer and efficiency for the DEH system η_{DEH} we will get the effect $\dot{Q}$ needed for the DEH cable on the flowline, and the new equation 4.10:

$$\dot{Q}_{DEH} = \frac{C_P \cdot m \cdot \Delta T}{t \cdot \eta_{DEH}} \qquad 4.10$$

Where

Q	=	heat transfer	$[kJ]$
$\dot{Q}$	=	heat transfer per time	$[w]$

C_P	=	specific heat capacity	$\left[\frac{kJ}{kg \cdot °C}\right]$
m	=	mass	$[kg]$
ΔT	=	delta temperature	$[°C]$
t	=	time	$[s]$
η_{DEH}	=	efficiency	$[dimension\ less]$

Table 4.7 Flowline heating

	6" flowline 2200m		8"flowline 6200m	
Production year	Re-heat from ambient in kw	Maintenance heating in kw	Re-heat from ambient in kw	Maintenance heating in kw
1	63	136	299	652
2	45	98	214	466
3	42	92	201	438
4	37	80	176	385
5	33	72	157	343
6	30	66	145	317
7	28	62	135	294
8	27	58	127	277
9	25	55	120	262
10	24	52	114	249
11	23	50	109	237
12	22	48	104	227
13	21	46	100	218
14	20	44	96	210
15	20	43	95	207
16	19	41	89	195
17	18	40	87	191
18	17	37	82	179
19	16	35	76	167

The effect needed in DEH system is largest in the beginning thereafter it is decreasing through the production lifetime. The point of time needed for heating is unpredictable and the system has to be design for the most power-consuming situation. For both the 6" and 8" flowline the most power-consuming situation is the maintenance heating of 2°C within 10 minutes the first year. For the 8" the needed effect is 652 kW and for the 6" the needed effect is 300 kW. The use of a DEH heating system require electrical power from the tie-in platform Gullfaks A. Local production stop of the O-template the DEH cable should be activated when the NTT exceeds. If a full platform blackout incident occur, the DEH cable must be activated when sufficient power is available and the operator should wait six hours or when the temperature is above the hydrate appearance temperature before consider starting up the O-template again.

4.4 Erosion GSO analysis

To check for possible erosion without the complete fluid property description, the empirical formula given in ISO 13703 is used. The empirical constant “c” is used as 180 due to the stainless steel 13%Cr alloy that the flowlines are made of. The following table includes an overview of the amount of each phase flowing.

$$v_e = \frac{c}{\sqrt{\rho}} \tag{4.6}$$

Where:

v_e	=	fluids erosional velocity	$\left[\frac{m}{s}\right]$
c	=	empirical constant	$[Dimensionless\ constant]$
ρ	=	fluids density	$\left[\frac{kg}{m^3}\right]$

Table 4.8 Erosional velocity

Production Year	Composed density in $\frac{kg}{m^3}$	Amount of gas in %	Amount of oil in %	Amount of water in %	Production velocity 8" in m/s	Production velocity 6" in m/s	Erosional velocity in m/s
1	332,27	69,69	30,13	0,18	0,2	0,4	9,9
2	232,25	84,17	15,00	0,83	3,0	5,1	11,8
3	213,82	87,36	10,22	2,41	8,1	13,8	12,3
4	189,02	90,30	8,18	1,52	8,9	15,2	13,1
5	168,66	92,71	6,15	1,14	11,6	19,6	13,9
6	156,28	93,99	5,21	0,81	11,9	20,2	14,4
7	145,24	95,09	4,34	0,57	12,2	20,8	14,9
8	136,70	95,86	3,71	0,43	12,5	21,3	15,4
9	129,19	96,50	3,14	0,37	12,9	21,8	15,8
10	122,78	96,98	2,71	0,32	13,2	22,4	16,2
11	117,01	97,37	2,33	0,30	13,6	23,0	16,6
12	112,13	97,63	2,10	0,27	14,0	23,7	17,0
13	107,51	97,86	1,90	0,24	14,4	24,4	17,4
14	103,51	98,00	1,77	0,24	14,7	24,9	17,7
15	102,08	97,81	1,87	0,32	8,2	13,9	17,8
16	96,18	98,20	1,50	0,30	8,7	14,8	18,4
17	93,88	98,13	1,47	0,40	6,3	10,7	18,6
18	87,86	98,53	1,06	0,41	4,4	7,3	19,2
19	82,04	98,87	0,83	0,30	2,9	4,9	19,9

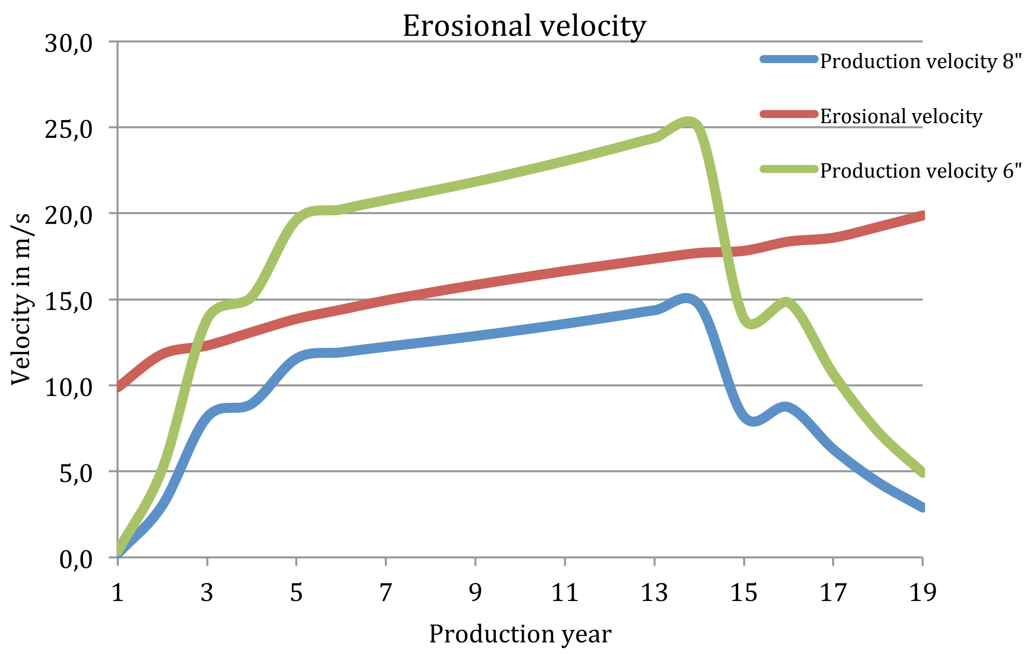

Figure 4.11. Erosional velocity.

The erosional velocity is based on an empirical formula that only includes the density of the flowing fluid besides the empirical constant. This empirical formula does not include the effect of any sand/solid production.

The 8” flowline is flowing with a velocity below the erosional velocity that is the maximum velocity before erosion could occur throughout the whole production life. However the well stream velocity is reaching towards the maximum velocity from year 5 till year 14, the well stream content during this time consist of 93%-98% gas. If production of any solid, the well stream will have a sandblast effect on the flowline and erosion could be severe. Closely monitoring of solid/sand production by sand detectors on the flowline or/ and physical tests of the well stream should be applied in this period.

The 6” flowline is producing above the erosional velocity already at year 3 of production. Production above the erosional velocity starts from year 3 and lasts throughout year 14 of the production life. The 6” flowline is not suitable for full production within these years even with no solid production.

4.5 Flow assurance summary

Slugs do not seem to be an issue under stable and normal production. The seabed is relatively flat and the water depth at the location is relatively shalom, therefor should not terrain slugs occur and riser slugs would not contain very large liquid if they should occur. The Reynolds number indicates that the flow is in a very turbulent flow regime all off the production life of the field. Under a production stop, the well stream will get a chance to separate it self in the flow and one could expect some slugs when starting back up again. This would not be fixed by flowline design either, but should be accounted for under production start up.

The arrival temperature is calculated for the 6” flowline to the G-template, and the arrival temperature at the platform for the 8” flowline. The well stream velocity will contribute a lot in how much heat is lost under transport from the well stream. The first and last year of production through the 8” flowline is the most critical regarding temperature. Both year 1 and year 19 the production through the 8” would possible be producing in the hydrate formation zone with the respective arrival temperature at 7°C and 22°C. The years in between should not be a problem regarding hydrate under steady production.

For the wax challenges through the 8” could year 18 of production in addition to year 1 and year 19 be an issue. It is also shown the temperature effect of changing the insulation of the flowline between U=4, U=5 and U=6. It indicates that the insulation class of the flowlines should have U-number even lower than 3 for any positive effect.

For the 6” flowline the arrival temperature on the G-template are above the hydrate formation temperature at the whole production lifetime, with the lowest arrival temperature at year 1 at 31°C. This is however in wax appearance temperature and could be an issue. The largest uncertainty for this flowline is the remaining flowline from G-template to arrival at the platform. Heat loss will of course happen here as well, but may be compensated for by other wells to increase both the temperature and well stream velocity.

The no touch time is the time where the production experience an unplanned stop and the well fluid are cooled down to it is reaching the hydrate appearance temperature, within this time there are no need for measures. If the incident that created the shutdown is fixed within this time, it is just to start up again. If not, there is still time for measure until hydrates will start to grow. For the 8” flowline the NTT is 0 minutes at year 1 and varies from 1hour and 16 minutes at year 2 and the NTT is reduced to 0minutes at year 18 and 19.

For the 6” flowline the NTT is 0 minutes at year 1 varies from 59 minutes to 21 minutes at year 19 of the production.

In addition to methanol injection at the wellhead and depletion of the flowline for hydrate measures, the GSO development has planned with a DEH cable on both the 8” and the 6”. These DEH cables will be the main measures for hydrate and wax challenges. It is assumed that they should be able to heat the well stream fluid from ambient temperature to 40°C within six hours, and they should be able to handle temperature changes at 2°C within 10 minutes for temperature maintenance. For both the flowlines the maintenance heating is the most power-consuming situation. The 8” with DEH demands 652 kW for the 6200m flowline, the remaining distance of the flowline are protected by bundle heating. The 6" flowline demand a DEH cable with capacity of 136 kW.

The erosional velocity is based on an empirical formula that only includes the density of the flowing fluid besides the empirical constant. This empirical formula does not include the effect of any sand/solid production. The 8" flowline velocity is under the erosional velocity for the production life, but it reaching for the limit from year 5 till year 14. Close attention to sand and solid production at this time should be attended. The 6" flowline exceeds the erosional limit from year 3 and last till year 14, this flowline is not suitable for full production within these years.

Table 4.9

<table>
<tr><th rowspan="2">Production year</th><th colspan="3">Suitability</th></tr>
<tr><th colspan="2">8" Flowline</th><th>6" Flowline</th></tr>
<tr><td>1</td><td>Hydrate</td><td>Wax</td><td>Wax</td></tr>
<tr><td>2</td><td colspan="2" rowspan="3">OK</td><td>OK</td></tr>
<tr><td>3</td><td rowspan="12">Erosion</td></tr>
<tr><td>4</td></tr>
<tr><td>5</td><td colspan="2" rowspan="10">No solid or sand production during these years</td></tr>
<tr><td>6</td></tr>
<tr><td>7</td></tr>
<tr><td>8</td></tr>
<tr><td>9</td></tr>
<tr><td>10</td></tr>
<tr><td>11</td></tr>
<tr><td>12</td></tr>
<tr><td>13</td></tr>
<tr><td>14</td></tr>
<tr><td>15</td><td colspan="2" rowspan="3">OK</td><td rowspan="5">OK</td></tr>
<tr><td>16</td></tr>
<tr><td>17</td></tr>
<tr><td>18</td><td colspan="2">Wax</td></tr>
<tr><td>19</td><td>Hydrate</td><td>Wax</td></tr>
</table>

Table 4.9 gives and overview of the suitability of the two production flowlines. It is assumed that the O-template is producing as the production profile indicates, and full production is either through the 8" or 6". Green colour indicates that the flowline is suitable, orange needs some extra attention and red indicates that the flowline is not suitable.

5 Discussion and conclusion

Even though the with all the experience gained over many years of oil and gas exploration on the Norwegian Continental Shelf, a standardized concept solution is not possible for field development. The GSO development is a further subsea development of an existing subsea development at the Gullfaks field. It is at a distance of 8-12km from the stand-alone platform Gullfaks A, where the GSO is tying-in to. The GSO reservoir was shown to be a quite complex reservoir and a total of six wells are to be drilled, four producers and two gas injectors. Due to the distance from Gullfaks A and the numbers of wells, I believe drilling the wells from Gullfaks A would be with too much uncertainties and a subsea solution is reasonable. The subsea solution is based on re-using some existing flowlines and tie-in points resulting in the GSO will have some limitations regarding the flowlines.

The development shall be tied back to the stand-alone platform Gullfaks A, this results in both opportunities and limitations. The GSO development was not assigned with an own J-tube for the tie-in, therefor tie-in to existing flowlines were chosen. The GSO development may not have been economical viable if not a tie-back was possible. Other producers are producing to the process facilities of Gullfaks A, the gas capacity may be a challenges when the GSO`s O-template will produce at its most. The platform can in addition to receive the well stream provide GSO with utility systems like electrical power, hydraulics and chemicals.

By re-using flowlines the expenses for the total development will be reduced, but tying-in to two different existing flowlines the dimensions are limited to these. Two production flowlines, one 8” and one 6” flowline, and one 8” injection flowline, these are analysed with respect to hoop and longitudinal stresses. It is assumed the material quality of the new flowlines tying-in to the old ones are the same. With this assumption the three flowlines are within the design criteria and applicable to use for the new GSO development with the external environment and the internal reservoir fluids.

Flow assurance is one of the critical design factors for a subsea development. The analysis of the different topics, slugging, hydrates, wax and erosion shows that the two production flowlines are not redundant to each other, but more a supplement to each other. Hydrates and wax challenges may be a problem in the beginning and end of the production life if using the 8”. The 6” flowline is within the criteria of hydrates throughout the whole production life, some wax challenges can be at the first year of production. Both the flowlines are installed with DEH, which the platform Gullfaks A can supply power for hydrate and wax measures. The 6” flowline is only useable in the first and last years of production regarding erosion if the O-template is producing at it max, even the 8” needs extra attention regarding erosion when the gas production is at its full.

The development of GSO is a sensible subsea development that will increase the recovery rate of the reservoir.

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7 Appendix

A-1

Production profile for the four producers O-1, O-2, O-3 and O-4.

O-1				
Production year	Oil prod per day in Sm^3	Gas prod per day in Sm^3	Water prod per day in Sm^3	GOR
Year 1	166	56381	1	340
Year 2	500	403825	6	808
Year 3	403	1138679	0	2826
Year 4	268	1155615	0	4316
Year 5	193	1199525	0	6221
Year 6	148	1200000	0	8083
Year 7	104	1200000	0	11546
Year 8	79	1200000	0	15269
Year 9	69	1197857	0	17274
Year 10	57	1188822	0	20785
Year 11	47	1182799	0	25200
Year 12	42	1177138	0	28164
Year 13	38	1169127	0	20683
Year 14	30	992284	0	33311
Year 15	1	19617	0	16255
Year 16	2	38047	0	16075
Year 17	3	42651	0	15222
Year 18	4	48600	0	12150
Year 19	7	116000	0	16571

A-2

O-2				
Production year	Oil prod per day in Sm^3	Gas prod per day in Sm^3	Water prod per day in Sm^3	GOR
Year 1	0	0	0	0
Year 2	642	584728	9	912
Year 3	573	1187104	17	2072
Year 4	375	1123228	12	2995
Year 5	302	1199520	11	3972
Year 6	286	1200000	11	4196
Year 7	271	1196315	10	4414
Year 8	241	1175686	9	4878
Year 9	210	1154870	9	5499
Year 10	190	1140255	8	6001
Year 11	164	1128808	8	6883
Year 12	154	1124183	8	7300
Year 13	152	1129305	7	7430
Year 14	145	1152734	8	7950
Year 15	36	357592	2	9933
Year 16	41	374648	2	9138
Year 17	25	256035	1	10241
Year 18	13	146700	1	11285
Year 19	8	99600	2	12450

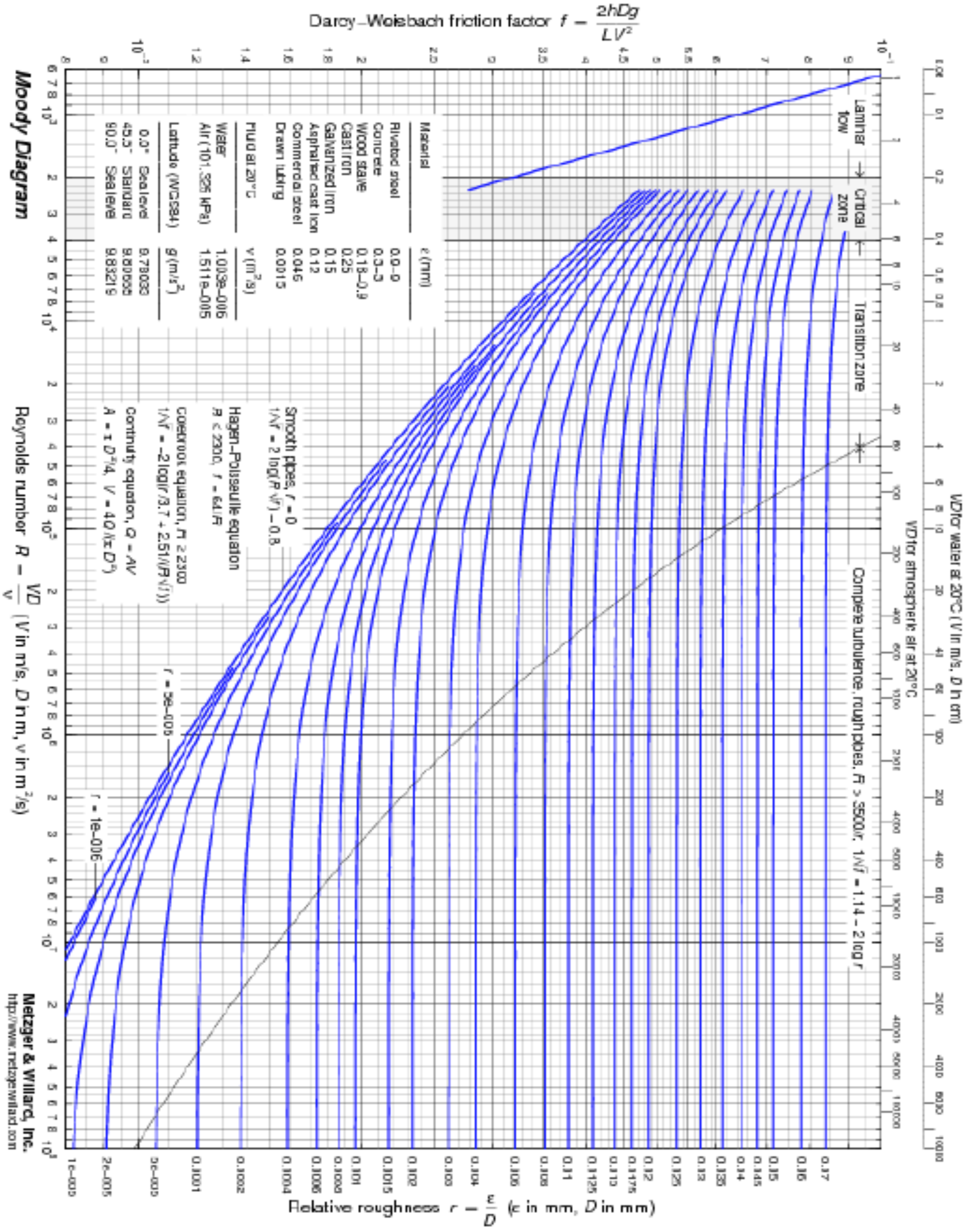
A-3

O-3				
Production year	Oil prod per day in Sm^3	Gas prod per day in Sm^3	Water prod per day in Sm^3	GOR
Year 1	0	0	0	0
Year 2	53	9455	51	178
Year 3	708	409512	419	578
Year 4	483	621117	180	1286
Year 5	579	1086729	140	1877
Year 6	464	903201	74	1947
Year 7	411	874903	60	2129
Year 8	369	876734	50	2376
Year 9	322	879907	50	2733
Year 10	299	882898	51	2953
Year 11	274	889978	48	3248
Year 12	251	892475	44	3556
Year 13	226	885299	42	3917
Year 14	223	957140	45	4292
Year 15	218	1200000	48	5505
Year 16	169	1200000	51	7101
Year 17	140	858900	55	6135
Year 18	68	640800	41	9424
Year 19	30	317900	18	10597

A-4

O-4				
Production year	Oil prod per day in Sm^3	Gas prod per day in Sm^3	Water prod per day in Sm^3	GOR
Year 1	0	0	0	0
Year 2	0	0	0	0
Year 3	511	92374	82	181
Year 4	800	228813	166	286
Year 5	800	570994	197	714
Year 6	738	830625	168	1126
Year 7	615	912677	113	1484
Year 8	537	955514	84	1779
Year 9	463	990922	65	2140
Year 10	397	1021890	51	2574
Year 11	349	1037470	51	2973
Year 12	326	1044553	46	3204
Year 13	305	1047198	41	3433
Year 14	285	1085422	38	3808
Year 15	148	672799	19	4546
Year 16	132	711111	17	5387
Year 17	76	451646	10	5943
Year 18	37	241800	5	6535
Year 19	18	155350	3	8631

B-1



Darcy–Weisbach friction factor $f = \frac{2hDg}{LV^2}$
Moody Diagram
Reynolds number $R = \frac{VD}{\nu}$ (V in m/s, D in m, ν in m²/s)
Relative roughness $r = \frac{\varepsilon}{D}$ (ε in mm, D in mm)
Laminar flow
Critical zone
Transition zone
Complete turbulence, rough pipes, $R > 3500/r$, $1/\sqrt{f} = 1.14 - 2\log r$
VD for water at 20°C (V in m/s, D in cm)
VD for atmospheric air at 20°C
Material ε (mm)
Riveted steel 0.9–9
Concrete 0.3–3
Wood stave 0.18–0.9
Cast iron 0.25
Galvanized iron 0.15
Asphalted cast iron 0.12
Commercial steel 0.046
Drawn tubing 0.0015
Fluid at 20°C ν (m²/s)
Water 1.0038e–006
Air (101.325 kPa) 1.5118e–005
Latitude (WGS84) g (m/s²)
0.0° Sea level 9.78030
45.5° Standard 9.80665
90.0° Sea level 9.83216
Smooth pipes, $r = 0$
$1/\sqrt{f} = 2\log(R\sqrt{f}) - 0.8$
Hagen–Poiseuille equation
$R \le 2300$, $f = 64/R$
Colebrook equation, $R \ge 2300$
$1/\sqrt{f} = -2\log(r/3.7 + 2.51/(R\sqrt{f}))$
Continuity equation, $Q = AV$
$A = \pi D^2/4$, $V = 4Q/(\pi D^2)$
r = 5e–005
r = 1e–006
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