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Abstract

As global energy demands continue to grow, the oil and gas industry is challenged to keep up the pace. The more easily accessible source of energy are getting scarcer, forcing the oil and gas industry to move into deeper waters and harsher environments. Development of Arctic shelf reserves is one of the areas oil and gas production can be maintained through. The Arctic shelf may become a significant source for long term production growth. However, severe Arctic conditions – the difficult ice conditions, challenging weather and lack of infrastructure – demand a different approach and technologies.

Gas and oil production in the Arctic is associated with the necessity of long distance transport causing transported natural gas and water to form gas hydrates. Hydrate formation followed by accumulation forms a slug. As the result, it leads to pipeline restriction and blockage. Clearly, these slugs will hinder the hydrocarbons to flow. To avoid this more and more attention has been paid to develop flow assurance approaches to prevent the formation of hydrate plugs.

Using a case study, this master thesis focuses on comparing employment of the innovative technology to avoid gas hydrates initiation and agglomeration – cold flow – in the Arctic with two conventional ones. Injection of thermodynamic inhibitors and direct electrical heating represent conventional technologies to tackle the hydrates in the case study. All the named techniques are applied to a fictional field development in the Arctic and analyzed on basis of their design, their environmental impact and challenges each of the methods has to face in the Arctic. Economical evaluation of hydrate preventing techniques is an essential part of this case study and includes capital and operational expenditure of employing each of the methods.

This master thesis concludes that the cold flow technology is the most favorable solution for the Arctic compared to the other technologies discussed in the report. Its simple design, low cost, good environmental performance, low maintenance and the potential to be installed on the distances longer than 200 kilometers makes it very attractive not only for the future field developments in the Arctic but also in the other different areas of oil and gas industry.

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1. Introduction

Formation and deposition of natural gas hydrates are by far the most important problems in offshore operations. This undesirable formation can lead to the pipeline blockage causing its rupture under the applied pressure. It can also clog equipment, preventing the optimum production of hydrocarbons. This follows by loss of money for the petroleum industry. This is because blockage point location is a hard job itself, and if blockage is far away from an access point it may be difficult to reach it with chemicals or remediation equipment, especially subsea. Therefore, preventative actions to control gas hydrate depositions have always been one of the main challenges and issues for oil and gas producers.

It is easier and economically reasonable to implement mitigation measures to avoid the initiation of the hydrates than deal with the existing problems. So water and condensate must be processed out. Normally, a platform or floating unit is needed to do that. Although, a storage for condensate is needed. In cold climate/Arctic region it should be possible to take the water out in a subsea separator. But what if there are no possibilities for offshore separation? Then long distance transportation of unprocessed gas cannot be avoided. An efficient solution of dealing with the flow assurance challenges in the Arctic is needed. Transport of multiphase wellstream on the long distance is of strategic importance for the future of field developments.

Long deepwater subsea tiebacks are problematic due to the high pressures and low temperatures of the production fluids in the flowline. Conventional methods for avoiding gas hydrate problems are generally based on one or a combination of the three following techniques: (1) removing the water, (2) injection of thermodynamic inhibitors, e.g. methanol, ethylene glycol, to prevent hydrate formation, (3) use of low-dosage hydrate inhibitors to sufficiently delay hydrate nucleation, and (4) maintaining pipeline operating conditions outside the hydrate stability zone by insulation and/or active heating. However, for many production operations, particularly deepwater field developments, fields with long tie-backs and field developments in the Arctic, the mentioned techniques can turn out to be expensive, impractical, and/or ineffective. Thus, the industry needs improved techniques to tackle flow assurance problems for such challenging conditions. The cold flow technology that is able to transport wellstream without any thermal or chemical treatment, aims to meet this need.

2. Objective and Method

The objective of the master thesis is to study and analyze the cold flow technology employed in the Arctic. A qualitative method is found to be suitable to investigate whether this innovative technology of cold flow is the most attractive one to deal with gas hydrates formation and deposition in the Arctic. It is performed by comparing it with a couple of conventional technologies, such as injection of thermodynamic inhibitors and direct electrical heating.

For successful comparison it is decided to carry out a case study and apply every discussed technology against gas hydrates to a field development in the Arctic. Since no fields in the Arctic have been discovered yet, the field in the case study is chosen to be fictional.

The applied in the thesis method of procedure is mainly of explorative form discovering important attributes for a technology to be attractive. Each applied hydrate preventing technique is analyzed on basis of their design, their environmental impact and challenges each of the methods has to face in the Arctic. Economical evaluation of hydrate preventing methods is an essential part of the conducted case study and includes capital and operational expenditure of employing each of the methods. After gaining a complete understanding of different techniques to avoid hydrates initiation and agglomeration, the advantages and disadvantages of each techniques have been considered.

Two major sources of information for this thesis are document investigation and interviews. Documents investigation provides background information. The use of internet is the fundamental source for the books, articles, and scientific papers. While the interviews provide practical information and personal opinions of the investigated question. The interview with the specialist was very helpful especially to gather information about the technology that is under development. Not so many papers and articles discussing and analyzing the cold flow technology have been published and are available.

3. Background

3.1 Gas Hydrates

A variety of gas hydrate researches have been done because gas hydrates are of interest primarily for three reasons:

- Gas hydrates are potential energy resource,
- The potential role of gas hydrates in climate change,
- Production (flow assurance) problems.

This report focuses on the gas hydrates as the flow assurance problems. Hydrates are one of the main challenges in the offshore production operations. Extensive studies have been conducting on the hydrates structure, their properties, dynamics of the hydrate formation and agglomeration. The goal of the research work is to understand the behavior and determine how to avoid plugging in pipelines.

Gas hydrates are crystalline compounds that form when water (or ice) contacts small molecules (called hydrate guests) under certain pressure and temperature conditions. The correct chemical name should be "gas clathrate hydrates", with a clathrate being a compound formed by the inclusion of molecules of one kind in the crystal lattice of another (water in this case). In practice, these compounds are commonly referred to as gas hydrates, clathrate hydrates, or just hydrates. While specific to the particular hydrate guest, gas hydrates are stable typically at high pressures and low temperatures. A wide range of molecules have been shown to form gas hydrates. Those of the most practical interest are light hydrocarbons such as methane, ethane, and propane. Carbon dioxide and hydrogen sulfide also form hydrates and are of particular interest. When hydrates form, water crystallizes to create a lattice of molecular-sized cages that trap guest molecules without chemical bonding between the host water and the guest molecules [10]. The inclusion or trapping of gas molecules in the gas hydrate lattice is shown on Figure 1. Generally speaking, each hydrate cage contains up to one guest molecule. Multiple cage occupancy can occur but normally exceptionally high pressure is required.

Hydrates are formed by hydrogen bond among water molecules. Results of these compounds molecule align to stabilize and precipitate into solid mixture [6].

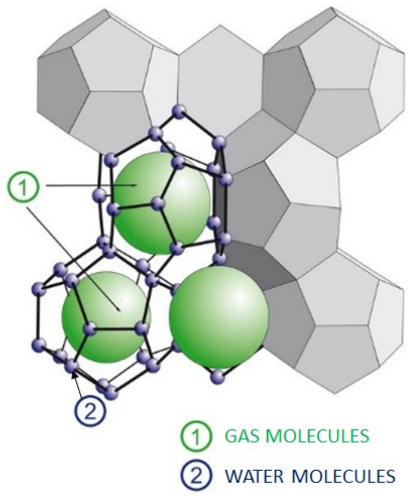

Figure 1. Inclusion or trapping of gas molecules in the gas hydrate lattice. The molecular-sized "cages" are composed of hydrogen bonded water molecules [10]

In physical aspect, gas hydrates are similar to ice or packed snow. Unlike ice, it is possible to burn the methane inside the hydrate and support a flame. It is clearly shown on the Figure 2.

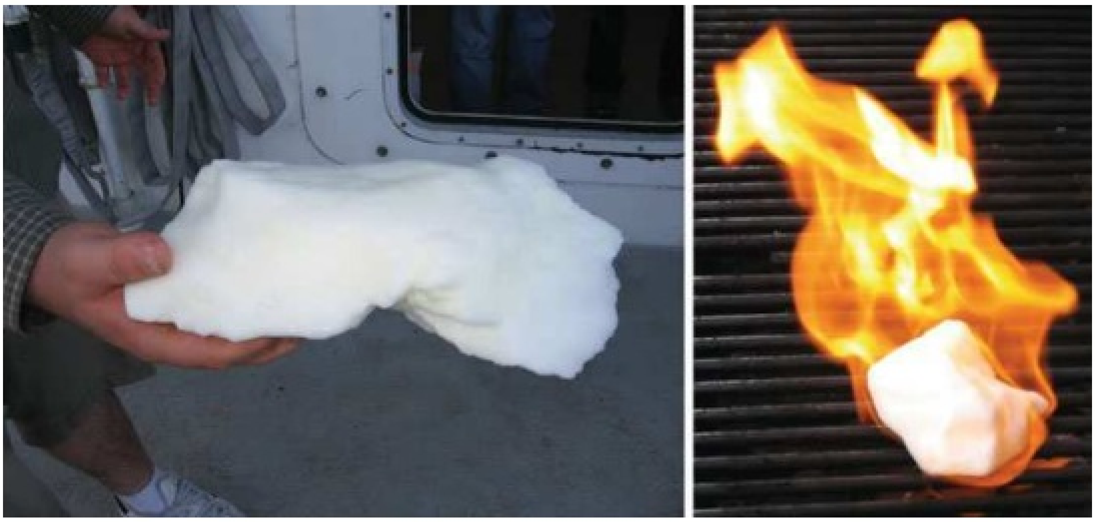

Figure 2. Gas hydrates [10]

Per unit volume, gas hydrates contain an enormous amount of gas. For example, 1 m^3 of hydrates disassociates at atmospheric temperature and pressure to form 164 m^3 of natural gas and 0,8 m^3 of water [22]. Volumetric proportions between water and gas in a methane hydrate is presented on Figure 3.

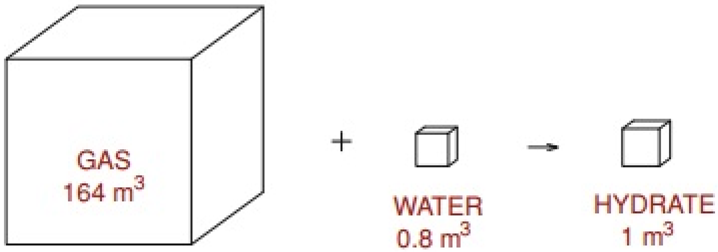

Figure 3. Volumetric proportions between water and gas in a methane hydrate [22]

3.2 Gas Hydrate Formation and Growth

The main aspect of gas hydrates studies is knowing under what conditions gas hydrates are stable. Gas hydrates are solid only under specific pressure-temperature conditions. Under the suitable pressure, they can exist at temperatures significantly above the freezing point of water. The maximum temperature at which gas hydrates can exist depends on pressure and gas combination. It is usually presented visually in the form of a Pressure-Temperature phase diagram. Hydrate stability can also be influence by other factors, such as salinity [8].

The hydrates can form anywhere that the following necessary conditions are met:

- The presence of sufficient quantity of water or ice,
- The presence of suitably sized gas/liquid molecules,
- Suitable temperature and pressure conditions (typically high pressure and low temperature).

Temperature and pressure conditions is a function of gas/liquid and water compositions. Figure 4 shows an example of a Pressure-Temperature phase diagram for a typical hydrate-forming hydrocarbon and water.

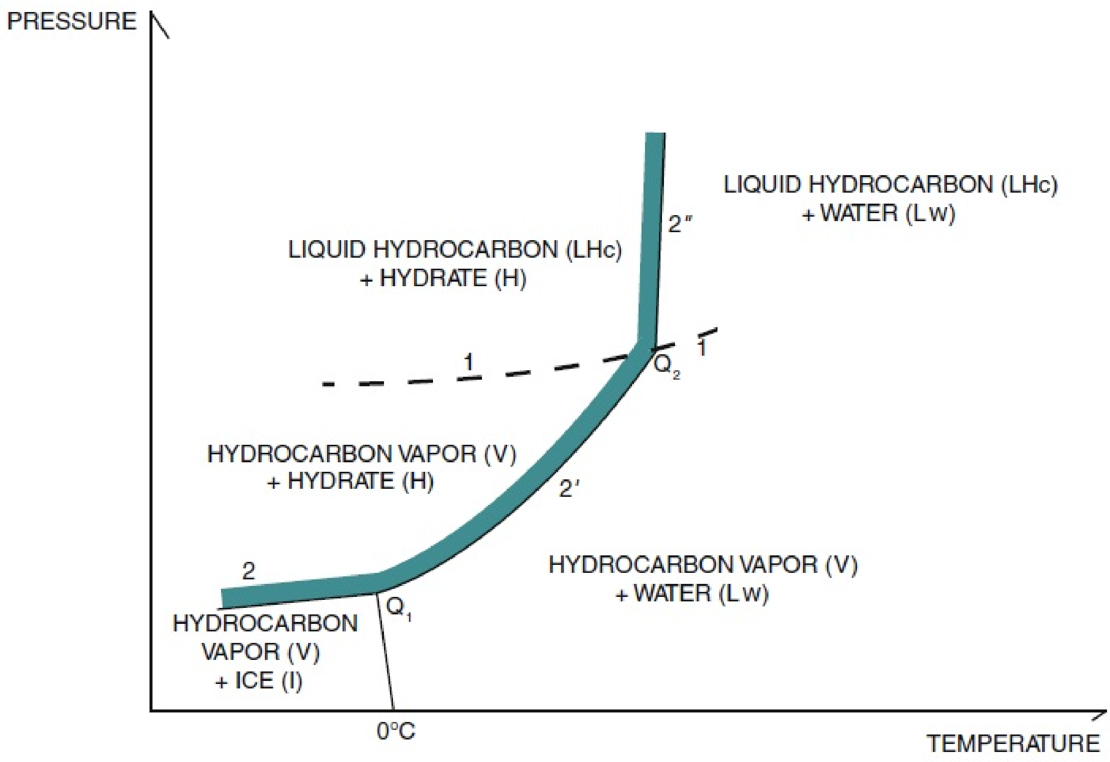

Figure 4. Pressure-Temperature phase diagram for a typical hydrate-forming hydrocarbon and water [10]

The hydrate stability curve ($2\text{-}2^{1}\text{-}2^{11}$) determines the point at which hydrate is stable. The hydrate stability area is to the left side of this curve where temperature is low and the pressure is high.

The first change in slope occurs at point Q_1, the lower quadruple point. At this point four phases exist simultaneously: liquid water (L_w), ice (*I*), hydrate (*H*) and hydrocarbon vapor (*V*). Below Q_1 hydrates form from ice instead of liquid water since temperature is below 0℃.

The second change in slope occurs at Q_2, the upper quadruple point. At this point liquid water (L_w), hydrate (*H*), hydrocarbon vapor (*V*) and liquid hydrocarbon (L_{HC}) exist simultaneously. The dashed curve illustrates the vapor pressure curve for the mixture and defines where the hydrocarbon change from the vapor to the liquid phase occurs.

After Q_2 the hydrate formation curve becomes significantly steeper establishing the top temperature limit for hydrate formation. Quadruple points are typical in hydrate-forming systems and each of them takes place at one specific pressure-temperature condition [10].

A pressure – temperature profile of the well fluid is added to the hydrate stability curve and is illustrated on Figure 5. It depicts pressure and temperature change of the well fluid at various points along the pipeline during production.

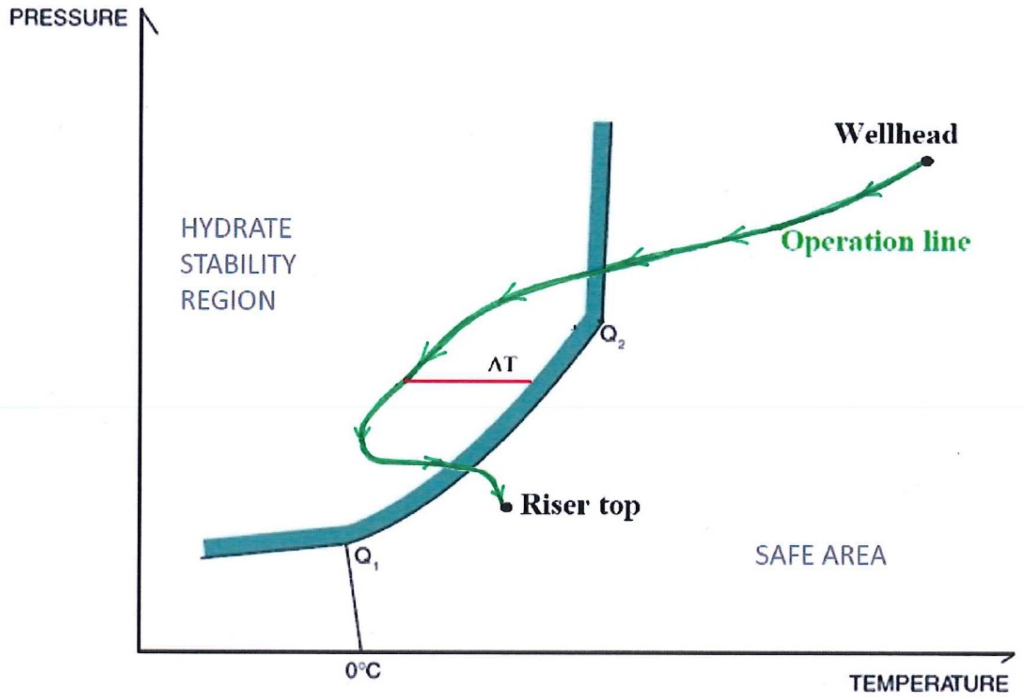

Figure 5. The curve of pressure - temperature profile during transport from the wellhead to the riser top

When the well fluid enters the pipeline, the pressure drops uniformly due to friction losses. The friction losses are associated with fluid flow, like water, oil and condensate that occurs together with the gas in the pipeline. The temperature change gains more interest in this profile. At some point during the transport from the weelhead to the surface both temperature and pressure can be found at hydrate formation zone. The seawater at the seabed provides constant cooling for the hot 40-80 °C well fluid coming from the reservoir. In case the travel distance for the well fluid is short, the well fluid will maintain some residual heat obtained from the reservoir. If the temperature of the well fluid can be maintained, flow can be assured to the processing facilities. In case the travel distance for the well fluid is long, the cooled well stream will cause, if unprotected, the formation of hydrates in the pipeline under these conditions. This would particularly occur during shutdowns and restarts. Some of the other scenarios of potential hydrate formation are:

- Gas expansion and cooling effect,
- Well clean-up and testing,
- Subsea separators,
- Long tie-backs,
- Deepwater petroleum production,
- Arctic on-shore petroleum production.

These undesirable formation can clog equipment, preventing the optimum production of hydrocarbons. The hydrate plugs can block the pipeline and cause its rupture under the applied pressure.

Before investigating various ways of avoiding and preventing hydrate formation, it is important to understand how hydrates grow. The process of hydrate growth can be described in different ways. The way that is presented in this report originally comes from SINTEF [23]. Hydrates start to nucleate close to the hydrocarbon phase on a water droplet in gas, oil or condensate phase. Hydrates start to grow along the droplet surface. They continue to grow until the whole droplet is fully covered with a thin layer of hydrate. The thin hydrate layer may contain a number of small cracks. Through these small cracks water in the water droplets penetrates from the inside to the hydrate surface surrounded by hydrocarbons. It is presented on the Figure 6.

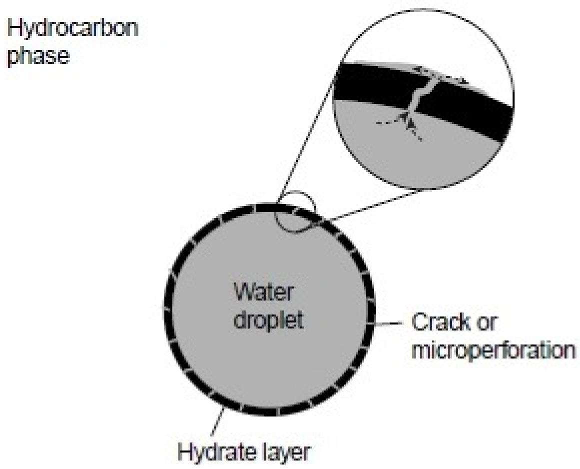

Figure 6. Hydrate growth on a water droplet [23]

If a water droplet covered by a hydrate film hits a pipe wall, it may cause the initiation of larger cracks in the film. Through these cracks water inside the droplet will drain out and spread on the dry layer of hydrates. Hydrate-forming species close to the pipe wall may transform this water in to the hydrate relatively quickly. As a result, the water/hydrate droplets may settle on the pipe wall.

In turbulent liquid environment the water phase is usually dispersed in the hydrocarbon phase as rough, unstable water-in-oil emulsions. Due to the hydrate layer, the surface tension of the droplets increases. So the water droplets agglomerate to larger droplets or water lumps in order to minimize surface area. These larger water droplets or lumps will change their shape, surface area and volume constantly. Thus, the thin layer of hydrates on the water droplet or water lump will get cracks or often get broken providing new water-hydrocarbon interfaces where more hydrates will form rapidly [23].

The water lumps continue to grow and accumulate particles. It will make the outer area of the water lumps stiffer. So when these lumps collide with each other or with a pipe wall, free water from the inside of the lumps will spread out to the surface of the hydrate film. It will act as "glue" for agglomeration of the lumps to larger lumps creating plugs or settling on the pipe wall as shown on Figure 7.

Figure 7. Hydrate deposition of the pipe wall [33]

4. Case Study: Polarrev Field Development

The purpose of this report is to compare the cold flow technology with the other proven technologies to prevent hydrate formation in the pipeline in the harsh environment of the Arctic. In order to achieve it, it is decided to conduct a case study investigating a field development in the Arctic region applying different methods to avoid initiation and agglomeration of hydrates in the pipeline. The selection of the field in the Arctic is required. It is worth mentioning the definition of the Arctic. The Arctic may be considered as a single region, but it can be defined and delineated in different ways. Figure 8 represents the boundaries variations the Arctic can have as it is seen by various scholars and organizations. Layers include environmental markers such as the treeline and 10℃ July isotherm, as well as definitions of the region created by the Arctic Monitoring and Assessment Program (AMAP). AMAP is an international organization established to implement the components of the Arctic Environmental Protection Strategy, which is under development [35].

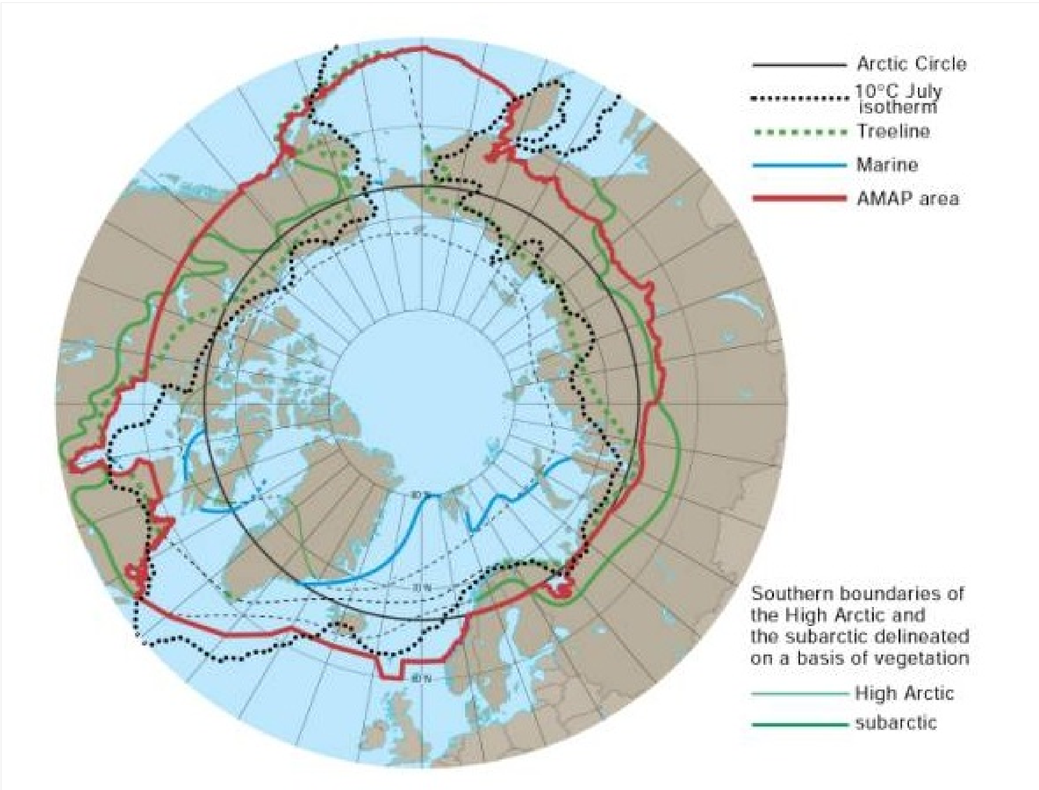

Figure 8. Different definitions of the Arctic [37]

The most explored areas of the Arctic shelf are the southern part of the Barents Sea (both the Russian and Norwegian sectors), the Kara Sea and the Beaufort Sea (both the American and Canadian sectors). These Arctic regions contain the majority of the discovered reserves of hydrocarbons. This report focuses only on the Norwegian side of the Arctic. The exploratory drilling has not been performed yet in this area.

The field for the study case is chosen to be situated on the Norwegian sector of the Barents Sea south-east of Svalbard where there are no any discovered fields yet. The field used for the study case, is imaginary. It does not exist. However, it might be in the future. Norwegian sector of the Barents Sea is chosen since the thesis is written in Norway and certain information is available for access. Figure 9 presents hydrocarbon resource potential of the Barents Sea as well as the location of the chosen field.

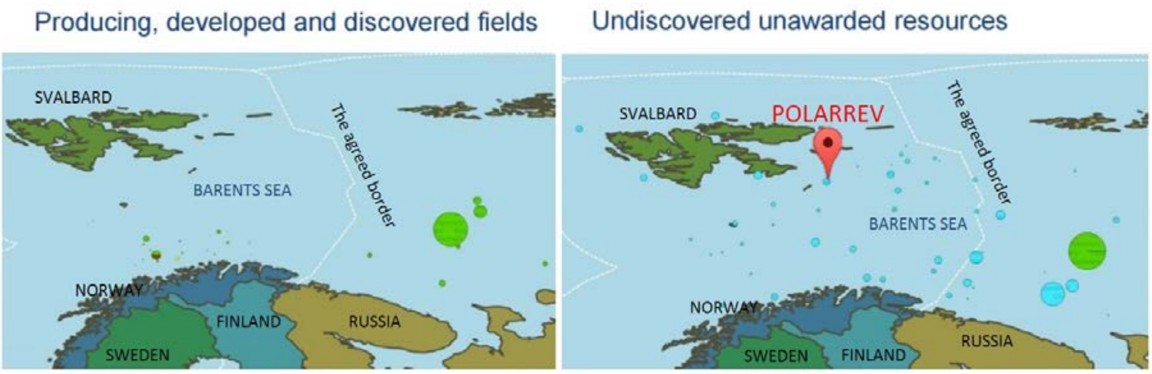

Table shows only undiscovered unawarded resources
Green circle (Shtokman) indicates the scale

Country	Province	Life Cycle Category	Resources Classification Proxy	Oil and Gas Group	Resources (Million bb
⊟ Norway	⊟ Barents Sea, NO	⊟ Undiscovered	⊟ Prospective Unawarded	Liquids	5 324
				Gas	8 387
				Total	13 711

Producing   Discovered   Undiscovered

Figure 9. Hydrocarbon resources of the Barents Sea [36] and the chosen location of the field for the case study

The Polarrev subsea development is an oil and gas field located 77° north latitude and 27° east longitude, East of Hopen, an island in the southeastern part of the Svalbard archipelago. It is about 650 kilometers offshore from Hammerfest, Norway. Production from Polarrev is processed at a fixed platform located 200 kilometers south of the field development. Water depth at the development is estimated to be 150 meters and at the platform location – 190 meters. These values seem to be reasonable since the average water depth in the Barents Sea is 230 meter and it gets shallower when continental landmasses and islands are approached. The selected field development concept where the untreated well stream is sent directly from subsea templates to an existing platform in one multiphase pipeline, is chosen due to its efficiency, cost effectiveness and possibility to tie in more subsea wells to the existing platform when they are discovered.

Polarrev features two 4-slot production templates as shown on Figure 10. The distance between them is estimated to be 200 meters. The hydrocarbon fluid will be produced from 6 wells. The recoverable reserves of oil are assumed to be one third of the Tyrihas gas and oil field development: 62x10^6 bbl (9,9x10^6 m^3).

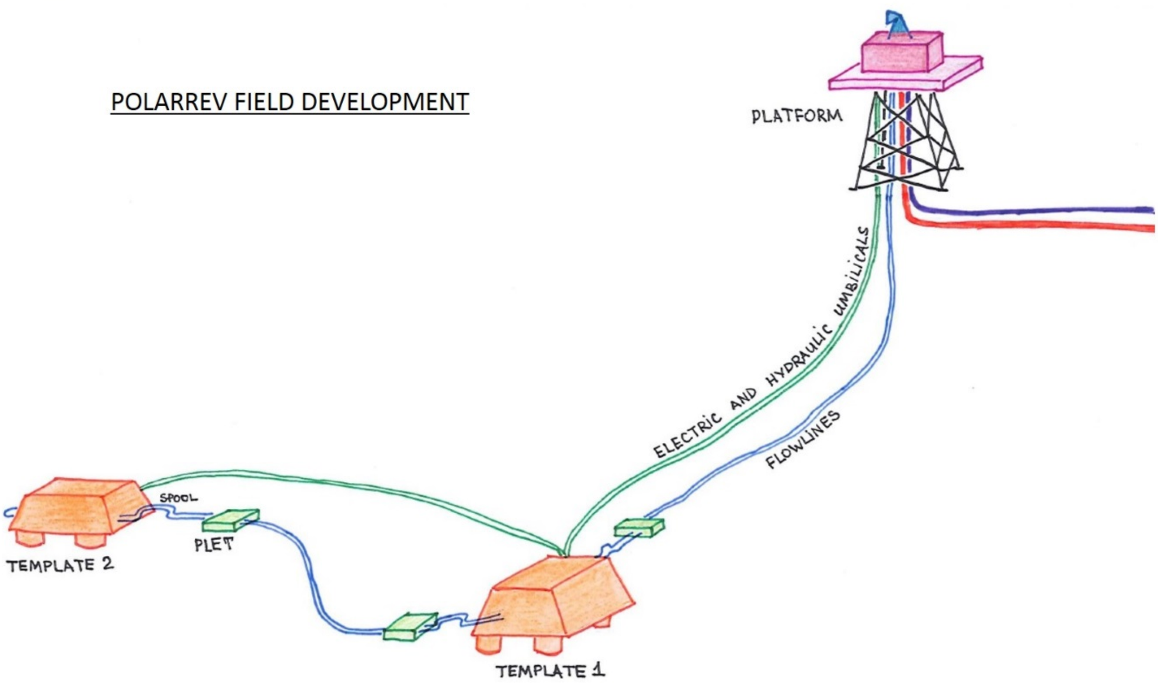

Figure 10. Subsea tieback system layout - production configuration with the host platform (made by author)

It is assumed that the produced fluid will be transported to the platform via dual 200 km 24'' multiphase flowlines. After processing, the dry export gas and oil is transported separately from the platform through 36'' pipeline each to the market. Analysis regarding pressure drop and liquid handling are beyond the scope of this thesis. Electric and hydraulic umbilicals link the processing platform to the subsea production system. The field is chosen to be not so large in order to simplify the calculations performed in Chapter 5 and Chapter 6. The summarized description of the Polarrev field development is presented in Table 1.

Table 1. Summarized description of the Polarrev field development

Parameter	Value
Distance to land, km	650
Distance to the process platform, km	200
Water depth, m	150
Number of wells	6
Number of templates	2
Distance between the templates, m	200
Recoverable reserves of oil, bbl	62×10^6
Flowline size, inch	24
Export gas pipeline, inch	36
Export oil pipeline, inch	36

In order to maintain the production plateau for as long as possible and recover oil, the anticipated gas and condensate resources, offshore compression is required to maintain production. Issues regarding drilling and installation of equipment in the Arctic area are beyond the scope of this master thesis.

The Polarrev field has one extreme factor that can lead to hydrate problems. It is sea bottom temperature: cold Arctic water from the north may cause the sea bottom temperature in some areas being close to 0℃. In situations where seabed temperature is very low, the most extreme cases of hydrate initiation occur at an emergency shut-in of the system. The cold flow technology aims to eliminate that issue at the Polarrev filed development. The availability and feasibility of applying this technique in the Arctic is discussed in the Chapter 5.

Prior to evaluate the feasibility of the cold flow concept against the conventional techniques at Polarrev, the production rate of the Polarrev field development at standard and subsea conditions has to be calculated. Standard conditions are established by the National Institute of Standards and Technology. They use a temperature of 20 ℃ and an absolute pressure of 1 atm (101 325 Pa). Mass rate of oil, gas and water has to be calculates also. It is assumed that the total mass rate is 29 kg/s. It is also assumed that the composition of gaseous phase in the wellstream does not vary with pressure and temperature under production [17]. GOR for Polarrev is assumed to be 250. WC is assumed to be 23%.

The combination of equations 4-1 – 4-5 are used to calculate mass rate of each compound at standard conditions.

$$m_{total} = m_{oil} + m_{gas} + m_{water} \tag{4-1}$$

$$q = \frac{m}{\rho} \tag{4-2}$$

$$m = q \cdot \rho \tag{4-3}$$

$$GOR = \frac{q_{gas}}{q_{oil}} \tag{4-4}$$

$$WC = \frac{q_{water}}{q_{water} + q_{oil}} \tag{4-5}$$

By rearranging the presented above equations, the equation for mass rate of gas is found.

$$m_{gas} = q_{gas} \cdot \rho_{gas}$$

$$q_{gas} = GOR \cdot q_{oil}$$

$$q_{oil} = \frac{m_{oil}}{\rho_{oil}}$$

$$m_{gas} = GOR \cdot \frac{m_{oil}}{\rho_{oil}} \cdot \rho_{gas} \tag{4-6}$$

Similar is done to find the equation for mass rate of water.

$$m_{water} = q_{water} \cdot \rho_{water}$$

$$q_{water} = WC \cdot (q_{oil} + q_{water})$$

$$m_{water} = WC \cdot (q_{oil} + q_{water}) \cdot \rho_{water} = WC \cdot \left(\frac{m_{oil}}{\rho_{oil}} + \frac{m_{water}}{\rho_{water}}\right) \cdot \rho_{water}$$

$$= \frac{WC \cdot m_{oil} \cdot \rho_{water}}{\rho_{oil}} + WC \cdot m_{water}$$

$$= \frac{WC \cdot m_{oil} \cdot \rho_{water} + WC \cdot \rho_{oil} \cdot m_{water}}{\rho_{oil}}$$

$$= \frac{WC \cdot m_{oil} \cdot \rho_{water} + WC \cdot \frac{m_{oil}}{q_{oil}} \cdot \rho_{water} \cdot q_{water}}{\rho_{oil}}$$

$$= \frac{WC \cdot m_{oil} \cdot \rho_{water} \cdot \left(1 + \frac{q_{water}}{q_{oil}}\right)}{\rho_{oil}} = \frac{WC \cdot m_{oil} \cdot \rho_{water} \cdot \left(\frac{q_{oil} + q_{water}}{q_{oil}}\right)}{\rho_{oil}}$$

$$1 - WC = 1 - \frac{q_{water}}{q_{oil} + q_{water}} = \frac{q_{oil} + q_{water} - q_{water}}{q_{oil} + q_{water}} = \frac{q_{oil}}{q_{oil} + q_{water}}$$

$$m_{water} = \frac{WC \cdot m_{oil} \cdot \rho_{water}}{(1 - WC) \cdot \rho_{oil}} \tag{4-7}$$

The rearrangement of equations to find mass rate of oil is shown below.

$$m_{oil} = m_{total} - m_{gas} - m_{water}$$

$$m_{oil} = m_{total} - GOR \cdot \frac{m_{oil}}{\rho_{oil}} \cdot \rho_{gas} - \frac{WC \cdot m_{oil} \cdot \rho_{water}}{(1 - WC) \cdot \rho_{oil}}$$

Dividing the equation by m_{oil} , obtain

$$1 = \frac{m_{total}}{m_{oil}} - GOR \cdot \frac{\rho_{gas}}{\rho_{oil}} - \frac{WC \cdot \rho_{water}}{(1 - WC) \cdot \rho_{oil}}$$

$$\frac{m_{total}}{m_{oil}} = 1 + GOR \cdot \frac{\rho_{gas}}{\rho_{oil}} + \frac{WC \cdot \rho_{water}}{(1 - WC) \cdot \rho_{oil}}$$

$$m_{oil} = \frac{m_{total}}{1 + GOR \cdot \frac{\rho_{gas}}{\rho_{oil}} + \frac{WC \cdot \rho_{water}}{(1 - WC) \cdot \rho_{oil}}} \tag{4-8}$$

It can be observed that mass flow rate depends on GOR and WC, which are assumed to be 250 and 23% respectively, and density of oil, density of gas and density of water, which is unknown.

The density of oil at standard conditions at Polarrev field development is assumed to be as at Tyrihans field development and equal to 879,2 kg/m^3 [24].

To calculate the density of gas at Polarrev at standard conditions it is assumed that specific gravity of the gas is 0,75. The composition of the gas extracted from the wells is assumed to contain 5 % hydrogen sulfide and 3 % propane. The molecular weight of the gas is calculated using Equation 4-6 and the assumption that specific gravity of the gas is 0,75. Specific gravity of the gas is set equal to the ratio of the molecular weight of the gas to that of air at standard conditions (T_{sc} = 20°C and P_{sc} = 1 atm) that is equal to 1,225 kg/m^3.

$$\gamma_{gas} = \frac{\rho_{gas}}{\rho_{air}} \tag{4-9}$$

$$\rho_{gas} = \gamma_{gas} \cdot \rho_{air}$$

$$\rho_{gas} = 0,75 \cdot 1,225 = 0,919\ kg/m^3$$

The density of the produced water in the wellstream, ρ_{water}, is assumed to be 1 013,5 kg/m^3. This assumption is based on the fact that the density of fresh water is 1 000 kg/m^3 and the average density of salt seawater is 1 027 kg/m^3. The mean value is taken for the assumption. The density of oil, gas and water is summarized in Table 2.

Table 2. Density of oil, gas and water at the Polarrev field at standard conditions

Density of oil, kg/m^3	Density of gas, kg/m^3	Density of water, kg/m^3
879,2	0,919	1 013,5

Taking the required assumptions into account and inserting the values of the density of each compound in the Equations 4-6 – 4-8, the mass rate of oil, gas and water at standard conditions is calculated below.

$$m_{oil} = \frac{29}{1 + 250 \cdot \frac{0,919}{879,2} + \frac{0,23 \cdot 1013,5}{(1-0,23) \cdot 879,2}} = 18,06\ kg/s$$

$$m_{gas} = 250 \cdot \frac{18,06}{879,2} \cdot 0,919 = 4,72\ kg/s$$

$$m_{water} = \frac{0,23 \cdot 18,06 \cdot 1013,5}{(1-0,23) \cdot 879,2} = 6,22\ kg/s$$

The results of the mass rate of oil, gas and water at standard conditions are summarized in Table 3.

Table 3. Mass rate of oil, gas and water and total mass rate at the Polarrev field at standard conditions

Mass rate of oil, kg/s	Mass rate of gas, kg/s	Mass rate of water, kg/s	Mass rate total, kg/s
18,06	4,72	6,22	29

The production rate of oil, gas and water at standard conditions is calculated by using Equation 4-2. The results as well as the density and mass rate of each compound are summarized in Table 4.

Table 4. Mass rate, density and production rate of oil, gas and water at the Polarrev field at standard conditions

		Oil	Gas	Water
Mass rate, kg/s		18,06	4,72	6,22
Density, kg/m^3		879,2	0,919	1013,5
Production rate	m^3/s	0,021	5,136	0,006
	m^3/day	1814,4	443 750,4	518,4

The density, flow rate and mass rate are calculated at the standard conditions, i.e. at surface. It is important to find out how these values will change at subsea conditions. Temperature at subsea conditions is assumed to be 50℃. Pressure at subsea conditions is assumed to be 160 bar. GOR and WC are identical for both standard and subsea conditions. In order to find the production rate of oil, gas and water at subsea conditions, Glasø's correlation is applied. This correlation based on data from North Sea reservoirs, is assumed to be applicable at Barents Sea reservoirs.

At subsea conditions the gas dissolved in the oil and the mass of the liquid phase enlarges. The pressure-volume behavior of liquid below the saturation pressure differs from the pressure-volume behavior of liquid above the saturation pressure. The saturation pressure for a gas-oil system is the pressure at which the gas solubility equals the producing gas/oil ratio. In the calculations presented in this report, the pressure at subsea conditions is assumed to be below the saturated pressure. In this case, both liquid and gaseous phases are presented at subsea conditions. At the same time expansion of the liquid volume by the dissolved gas may be expected. The liquid volume can also be expended by increased temperature. However, when the temperature increases, gas solubility reduces. The overall effect of pressure increase at constant temperature results in increased liquid volume. While temperature increase at constant pressure results in reduced liquid volume. The reduction of liquid volume is caused by vaporization. All these effects are quantified in the Glasø's correlation [2].

Both oil formation volume factor and gas formation oil factor have to be found since these values are dependent on temperature and pressure. Equation 4-9 is used to find the oil formation volume factor.

$$B_{oil} = 1 + 10^{(-6,58+2,91(\log_{10} B^*)-0,276(\log_{10} B^*)^2)} \tag{4-10}$$

Where B* is coefficient that can be found by Equation 4-10.

$$B^* = 5{,}615 \cdot \left(\frac{\gamma_{gas}}{\gamma_{oil}}\right)^{0{,}526} \cdot R_s + 1{,}74 \cdot T - 445 \tag{4-11}$$

Where γ_{oil} – the specific gravity of oil,

R_s– the gas solubility, Sm³/Sm³,

T – fluid temperature, K.

To find the specific gravity of oil Equation 4-11 should be applied where water is given as the reference substance. The density of water at 4°C is 1 000 kg/m³.

$$\gamma_{oil} = \frac{\rho_{oil}}{\rho_{water}} \tag{4-12}$$

$$\gamma_{oil} = \frac{879{,}2}{1000} = 0{,}88$$

The gas solubility is equal to the production gas/oil ratio which is 250 in the Polarrev field development case. Knowing that the temperature at subsea conditions is 50°C or 323,15 K, the coefficient B^* and then oil formation volume factor can be found.

$$B^* = 5{,}615 \cdot \left(\frac{0{,}75}{0{,}88}\right)^{0{,}526} \cdot 250 + 1{,}74 \cdot 323{,}15 - 445 = 1407{,}8$$

$$B_{oil} = 1 + 10^{(-6{,}58+2{,}91(\log_{10} 1407{,}8)-0{,}276(\log_{10} 1407{,}8)^2)} = 1{,}7$$

So, the oil formation volume factor is equal to 1,7. The gas formation volume factor is by definition the ratio of volume at given temperature and pressure, to volume at standard surface temperature and pressure [2].

The volumetric behavior of gas is described by the general gas equation.

$$P \cdot V = n \cdot z \cdot R \cdot T \tag{4-13}$$

By the general gas equation, the gas formation volume factor is expressed by Equation 4-14.

$$B_{gas} = \frac{P_{SC}}{P} \cdot \frac{T}{T_{SC}} \cdot \frac{z}{z_{SC}} \tag{4-14}$$

Where z – the gas z-factor or supercompressibility factor.

At surface standard conditions natural hydrocarbon gas behaves close to ideal, i.e. z=1 at surface pressure. At subsea conditions, the supercompressibility factor is usually in the order of 0,7-0,9. In the current study case the supercompressibility factor is assumed to have the mean value, i.e. 0,8.

$$B_{gas} = \frac{1{,}01}{160} \cdot \frac{(273{,}15 + 50)}{(273{,}15 + 20)} \cdot \frac{0{,}8}{1} = 0{,}0056$$

When both the gas formation volume factor and the oil formation volume factor are calculated, the density of oil and gas at subsea conditions can be expressed by using Equation 4-15 and Equation 4-16 respectively.

$$\rho_{oil\_subsea} = \frac{\rho_{oil} + \rho_{gas} \cdot R_s}{B_{oil}} \tag{4-15}$$

$$\rho_{gas\_subsea} = \frac{P \cdot M_{gas}}{z \cdot R \cdot T} \tag{4-16}$$

Where M_{gas} - is the molecular weight of the gas, g/mol
R – is the ideal, or universal gas constant; R is equal to 8,314 J/K·mol

To calculate the molecular weight of the gas can be found by using specific gravity of the gas, which is set equal to the ratio of the molecular weight of the gas to that of dry air. The molecular weight of dry air is equal to 28,967 g/mol.

$$\gamma_{gas} = \frac{M_{gas}}{M_{air}} \tag{4-17}$$

$$M_{gas} = \gamma_{gas} \cdot M_{air}$$

$$M_{gas} = 0{,}75 \cdot 28{,}967 = 21{,}735\ g/mol$$

Thus, the density of gas and oil at subsea condition is calculated.

$$\rho_{gas\_subsea} = \frac{160 \cdot 10^5 \cdot 21{,}735}{0{,}8 \cdot 8314 \cdot (273{,}15 + 50)} = 161{,}8\ kg/m^3$$

$$\rho_{oil\_subsea} = \frac{879{,}2 + 0{,}919 \cdot 250}{1{,}7} = 652{,}3\ kg/m^3$$

Density of oil, gas and water at subsea conditions is summarized in Table 5.

Table 5. Density of oil, gas and water at the Polarrev field at subsea conditions

Density of oil, kg/m^3	Density of gas, kg/m^3	Density of water, kg/m^3
652,3	161,8	1013,5

Using Equations 4-6 – 4-8 mass rate of oil, gas and water is calculated and summarized in Table 6.

$$m_{oil} = \frac{29}{1 + 250 \cdot \frac{161,8}{652,3} + \frac{0,23 \cdot 1013,5}{(1-0,23) \cdot 652,3}} = 0,46\ kg/s$$

$$m_{gas} = 250 \cdot \frac{0,46}{652,3} \cdot 161,8 = 28,34\ kg/s$$

$$m_{water} = \frac{0,23 \cdot 0,46 \cdot 1013,5}{(1-0,23) \cdot 652,3} = 0,20\ kg/s$$

Table 6. Mass rate of oil, gas and water and total mass rate at the Polarrev field at subsea conditions

Mass rate of oil, kg/s	Mass rate of gas, kg/s	Mass rate of water, kg/s	Mass rate total, kg/s
0,46	28,34	0,20	29

The production rate of oil, gas and water at subsea conditions is calculated by using Equation 4-2. The results as well as the density and mass rate of each compound are summarized in Table 7.

Table 7. Mass rate, density and production rate of oil, gas and water at the Polarrev field at subsea conditions

		Oil	Gas	Water
Mass rate, kg/s		0,46	28,34	0,20
Density, kg/m^3		652,3	161,8	1013,5
Production rate	m^3/s	0,0007	0,175	0,0002
	m^3/day	60,48	15 120	17,28

Comparing Table 4 and Table 7, it can be concluded that the mass rate of gas at subsea conditions is significantly higher than at surface condition. The opposite effect occurs with the oil when the mass rate at subsea conditions is much lower than the mass rate at surface conditions. It can be explained by the effect of increased pressure and temperature at subsea conditions. This will affect the production rate of oil and gas at Polarrev field development.

The assumptions regarding the Polarrev field development are used for calculations in Chapter 6 and Chapter 7 in this master thesis. The assumed parameters are summarized and presented in Table 8. To calculate the economic effect of each hydrate prevention technique requires another set of assumptions. These assumptions are presented in every chapter where they are applied, together with some of the general assumptions listed in Table 8.

Table 8. General assumptions regarding the Polarrev field development

Parameter	Value
Distance from the field to the host platform, m	200 000
Water depth at the field, m	150
Water depth at the host platform location, m	190
Distance between the templates, m	200
Number of produced wells	6
Recoverable reserves of oil, bbl	62×10^6
Outer diameter of the production flowline, inch	24
Total mass rate, kg/s	29
GOR, Sm^3/m^3	250
WC, %	23
Density of oil at standard conditions, kg/m^3	879,2
Specific gravity of the gas	0,75
Amount of hydrogen sulfide in the gas composition, %	5
Amount of propane in the gas composition, %	3
Density of produced water, kg/m^3	1 013,5
Temperature at subsea conditions, °C	50
Pressure at subsea conditions, bar	150
Supercompressibility factor	0,8

5. Cold Flow Technology

In the early 1990's Norwegian University of Science and Technology (NTNU) carried out an experiment that showed that natural gas hydrate slurry in a circulation loop did not accumulate on pipe walls under the condition where the temperature is constant. The gas hydrates particles produced in a continuous stirred tank reactor were small, 1-10 micrometer, and stayed suspended in the liquid phase even under shut-in for a day. That is how the idea of cold flow started.

According to Gudmundsson (Gudmundsson, 2012) in cold flow hydrate particles suspended in the liquid phase if the temperature is constant in subsea pipeline, will not deposit on the pipe wall. Before entering the pipeline the natural gas hydrate particles must be produced and cooled down to the surrounding seawater temperature [15].

As it is indicated in Chapter 3.2, if water is to be transported as a stable hydrate slurry, the hydrates must contain no free water in order to avoid hydrate depositions on the pipe wall or hydrate accumulation. To achieve the absence of free water, free water has to be converted in to hydrates close to the production well. It has to be done in a controlled manner as well as fast so no water is available for further hydrate formation and thus no more solids will be able to deposit out.

A wellstream consisting of oil and condensate is warm and contains free water droplets. If this wellstream is mixed with a cooled wellstream containing plenty of dry hydrate particles, these hydrate particles will be quickly covered by the water. It creates a thin water film around the hydrate particles. As long as the temperature conditions are suitable, the water will be converted in to hydrates by growing from the existing hydrate surface and outwards, as it is shown in Figure 11 [23].

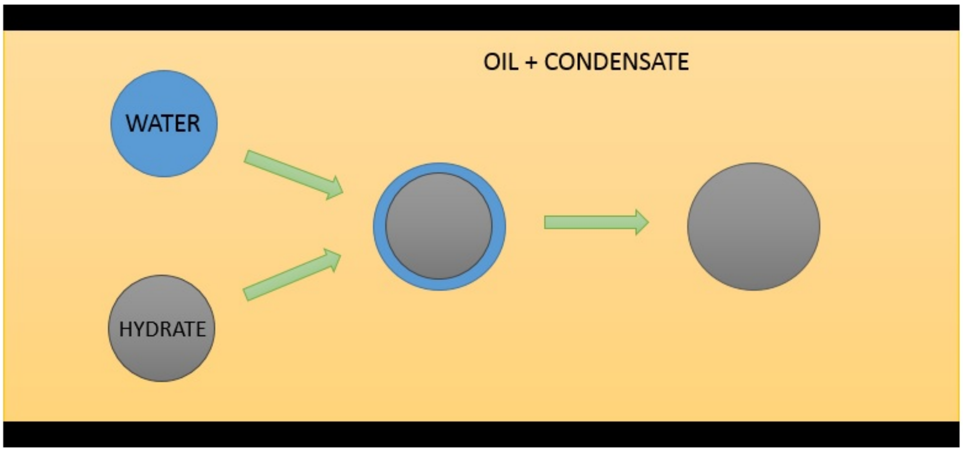

Figure 11. Converting the water layer to hydrates

So cold flow technology is based on slurry transport of hydrate particles. It will only take place when the steady-state operating conditions have been reached.

Cold flow technology allows subsea field development with ultra-long cold multiphase wellstream transport. This technology is developed with a goal to eliminate the need of chemical injection and heating of the pipeline.

Nowadays there are three concepts based on the cold flow technology that were developed by different organizations:

- SINTEF-BP concept that is initially developed internally at SINTEF Petroleum Research,
- NTNU concept that is developed at Norwegian University of Science and Technology by Gudmundsson,
- HYDRAFLOW concept that is developed at the Centre of Gas Hydrate Research at Heriot Watt University.

The description of each concept is presented in the next chapters.

5.1 The SINTEF-BP Concept

In the late 1990s, SINTEF Petroleum Research developed and patented a concept – SATURN Cold Flow Patented Technology. BP became a partner in it later. The SATURN concept is based on seeding and growing the hydrate from inside and outwards eliminates the availability of free water. The name SATURN for the concept was chosen because of the analogy with the rings of the planet Saturn associated with hydrate particles in recirculation, and from the realization that Saturn was the old Roman god of "seeding and sowing" [23].

A wellstream from a production subsea well contains water and hydrocarbons. According to this concept, the water content should be reduced from the production stream by a free-knockout of water i.e. using a vertical or horizontal separator. It reduces the water content to maximum 20%. After that the wellstream is lead into the hydrate reaction part of the system where hydrate particles in a cold fluid are pumped in from a downstream splitter.

The water in the wellstream will be converted in to dry hydrate particles longer before it reaches the splitter. This will be done by the fact that the bare pipe is exposed to surrounding ambient sea temperature of -2 to 4 °C. In the splitter some of the cold hydrocarbon fluids and dry hydrate particles are split off and recirculated to the process starting point. The aim of splitting the flow is to have some of the fully converted particles proceed downstream in an amount corresponding to the content of water in the inflow to the system. A schematic description of the SINTEF's concept is shown in Figure 12 and in Figure 13.

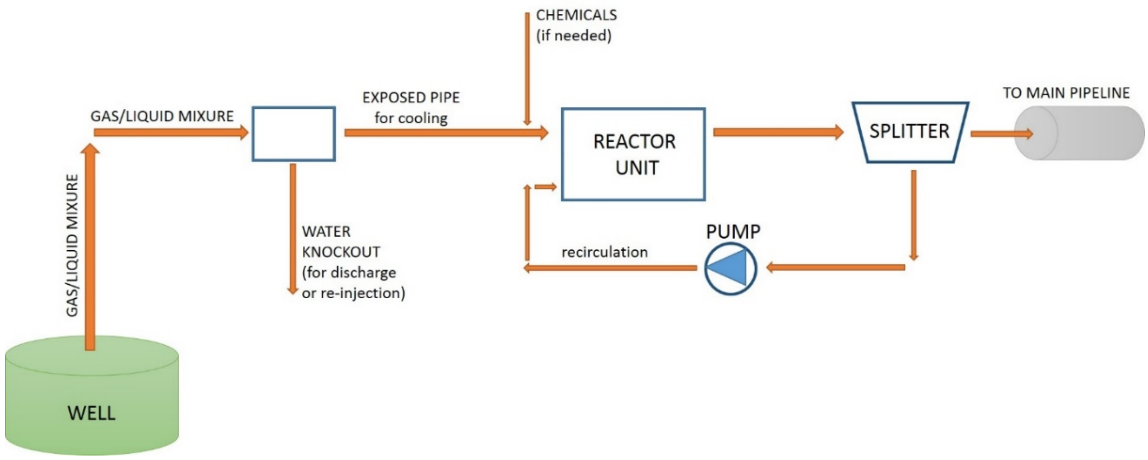

Figure 12. A schematic description of the SINTEF concept

The particles escaping without recirculation will be solid, dry hydrate. The additional cooling ensured by uninsulated steel pipe brings the system to ambient sea temperature. This prevents condensation of water from liquid or gas hydrocarbons through the rest of the pipeline.

At the end of the transport through the pipeline, the temperature increases and the pressure drops. The hydrate particles will not melt to free water and natural gas. In the end the hydrate particles may be mechanically separated or by gravity in a separator.

The SATURN concept by SINTEF-BP is not limited to a single well or template. It can be implemented to produce a cold slurry from a chain of wells and templates or from an entire field. Whether there is more than one well included, then the loop may be enlarged so that only one splitter or recirculation loop is required.

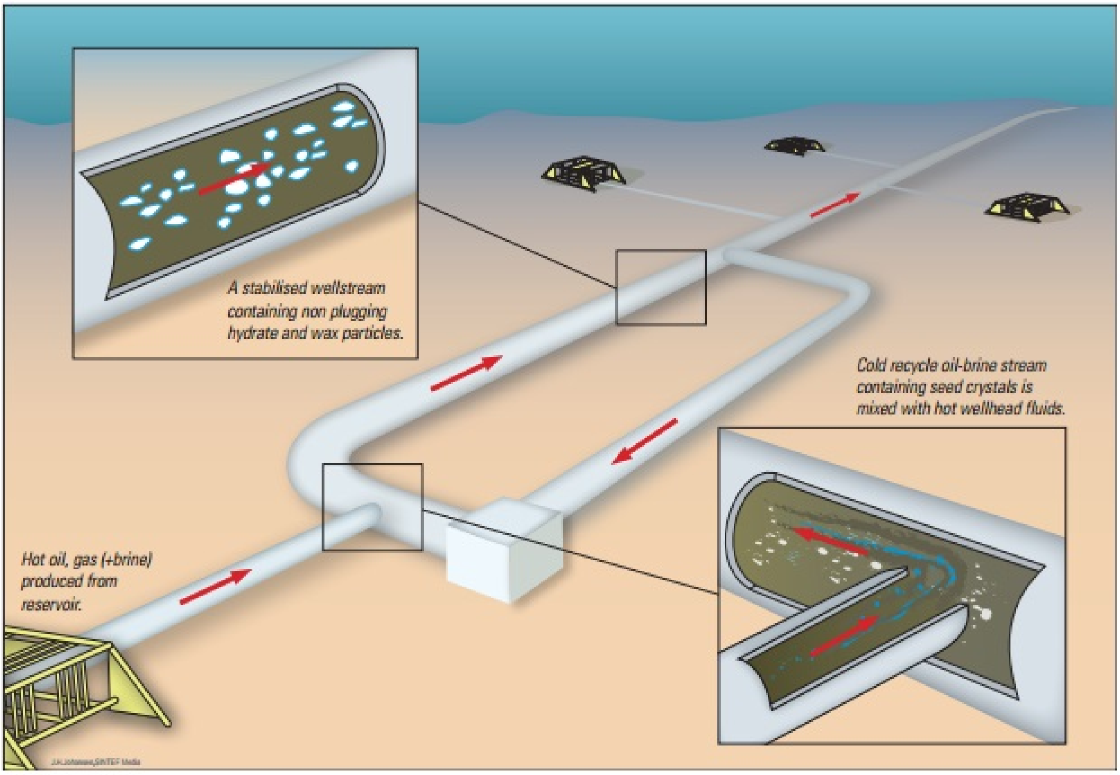

Figure 13. A schematic description of the fluid mixing in the SINTEF concept [18]

According to Tvedt (Tvedt, 2005) in his personal communication with Senior Research Scientist Roar Larsen, SINTEF Petroleum Research, the variation in viscosity will be a limitation on transport over long distances. High viscosity will lead eventually to large pressure drop [34]. Though Gudmundsson (Gudmundsson et al. 1999) conducted an experiment and presented that the amount of hydrates up to 30 percent did not really give a measurable change in the viscosity of the fluid, although different types of oil would demand flexibility in the operational conditions [12].

The SINTEF-BP concept was developed with oil fields as initial target with some amount of gas but gas and condensate fields will be incorporated in the future. This concept has flexibility in slurry transport ensuring either all the water or all the gas completely used up to avoid further hydrate formation and following problems over long distance transport. If GOR is high, hydrate formation will also be high. Whether it is assured that all the water or gas is totally gone, it will not be any issues. SINTEF-BP concept is developed to prevent both wax and hydrates. Tests conducted in their laboratory showed the significantly reduced wax formation with the cold flow system than without it. However, there is no sufficient evidence proving that wax will not be a problem [34]. SINTEF-BP says that asphaltenes and scale will not be an issue either.

5.2 The NTNU Concept

The next concept presented in this report is the NTNU concept. It has been developed at the Department of Petroleum Engineering and Applied Geophysics at NTNU, Trondheim, by Professor Jon Steinar Gudmundsson. The NTNU concept has a lot of similarities with the SINTEF-BP concept. This concept is based on forming hydrate particles from an associated gas and water before they enter the pipeline. The hydrate particles will then flow with oil in a three-phase flow together with surplus gas [14]. This will eliminate the problems of hydrate and wax deposition in the subsea pipeline in a steady state. The NTNU and SINTEF-BP concepts have different ways of cooling. In the NTNU concept the wellstream has to be cooled at the heat exchanger unit.

The concept involves the presence of several main process units:

- Wellhead unit,
- Separator unit,
- Heat exchanger unit ,
- Reactor unit.

The main component units are shown in the Figure 14. The hot production stream flows from the production well into the wellhead unit. Then the wellstream reaches the subsea separator unit where it will be separated into liquid and gas. The liquid phase goes into heat exchanger unit. The gas goes directly into the reactor unit where it meets the cooled liquid phase. Both gas and the cooled liquid phase mixes together creating a hydrate slurry a result of high pressure and low temperature. This hydrate slurry will be sent to the cold flow pipeline. This process is schematically described in the Figure 14.

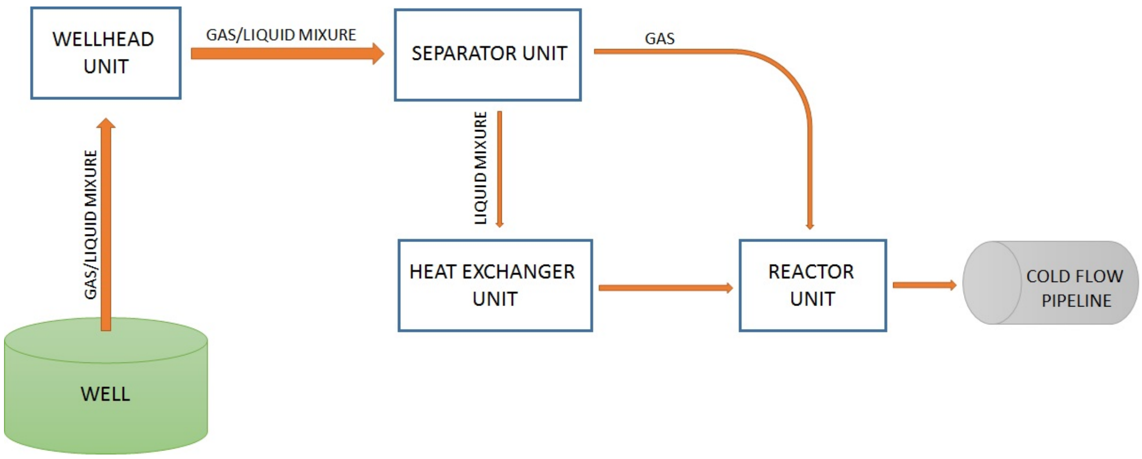

Figure 14. A schematic description of The NTNU concept

As it is mentioned above, the NTNU concept has a different way of cooling. In this concept the heat exchanger unit comprises two units for cooling: a normal tube heat exchanger unit and a refrigeration unit. They are shown in Appendix 1 and Appendix 2, respectively. Both of cooling units are required because there is a reasonable limit of volume of heat that can be transported away by one unit from a medium given the surrounding conditions without becoming too extensive. In the tube heat exchanger the liquid will not be cooled down to the required ambient seawater temperature. Although, it can be cooled down to approximately 10℃. The remaining cooling down to the ambient seawater temperature will be continued in the refrigeration unit. It should be conducted by using a compressor. The process of gas cooling requires much less effort. That is why it is not necessary [13].

At the final destination, receiving terminal onshore or production site, it is proposed to use a conventional technology for the slurry separation. The produced crude (oil, gas and water) are separated as the slurry stream is continuously fed to the heating and melting units. The receiving terminal can also be integrated into an existing refinery complex or being implemented form the beginning [12].

This concept has some limitations. According to Tvedt (Tvedt, 2005), high viscosity can cause high pressure drop in the pipeline during transport over long distances. In order to identify this, it requires a pipe with a larger diameter. Tvedt suggests that the increase in size around 5-10 percent would be sufficient. However, the risk in this case is as big as the risk of chemical usage in a bare steel pipeline which also requires a larger pipeline diameter [34].

Wax deposition in pipeline is another limitation in the NTNU concept. Obviously, chemical injection can be used in a case where cold flow technology cannon tackle it on its own. Although, it is not preferable as well as for scales and asphaltenes.

5.3 The HYDRAFLOW Concept

HYDRAFLOW is a patented cold flow assurance technology that is developed at the Centre for Gas Hydrate Research, Heriot-Watt University. The project started in September 2005 with support from Scottish Enterprise Proof of Concept Program by constructing a high pressure Flow Loop.

The term HYDRAFLOW got its name to distinguish it from "dry" hydrate concepts. The HYDRAFLOW concept is based on allowing formation of gas hydrates but preventing agglomeration of them using low doses (few percent by mass) of chemical anti-agglomerants (AA) where it is necessary. The use of anti-agglomerants is required to control the hydrate-crystal size as well as preventing blockage in the system. The goal is to minimize or fully eliminate the gas phase by converting it into hydrates. It is achieved through reaction with produced water or added water.

This concept proposes to recycle liquid phase as part of a "Loop" concept wherein the recycled fluid plays the role of carried fluid. This carried fluid collects produced fluids from different wells reacting with the gas phase to form hydrates. Then it transports those hydrates as hydrate slurry in oil and/or water to production facilities [3]. This whole process is illustrated in Figure 15.

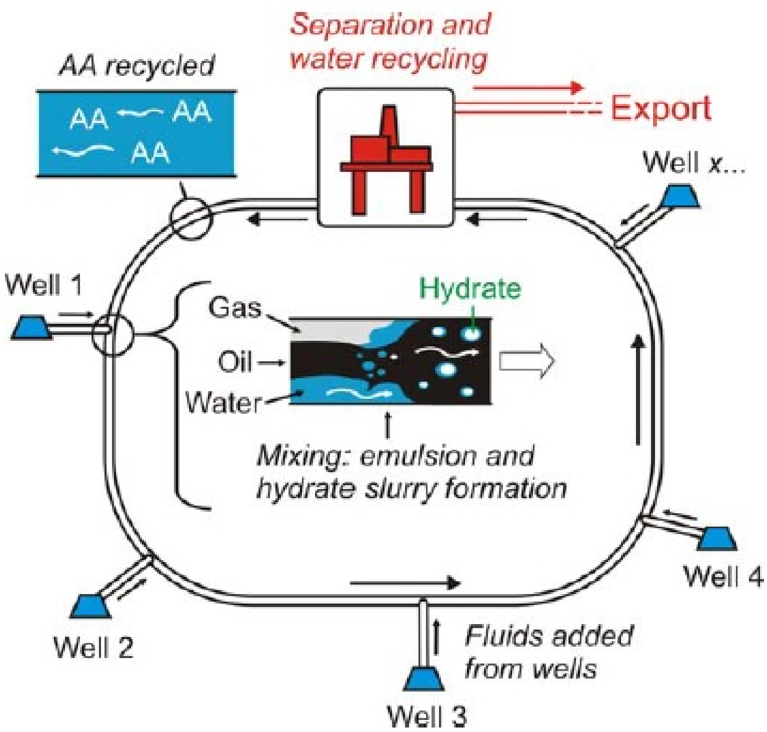

Figure 15. Illustration of the HYDRAFLOW pipeline "Loop" concept [3]

The main components of HYDRAFLOW concept are: the separation unit and water recycling unit, pipeline loop system connecting different wells, injection lines for the chemicals and the excess water and a single phase pump that is located at the receiving facilities. This concept utilizes subsea bare pipelines as the reactor where the produced stream mixes together in hydrate slurry. The presence of excess water and low doses of chemicals if necessary helps controlling the slurry viscosity and prevents hydrates agglomeration. [3]

The proposed HYDRAFLOW concept unlike the other cold flow concepts promises to reduce or even eliminate the risks of hydrate blockage. Converting the gas phase into hydrates leads to reduction of density difference between phases. It helps to reduce slugging problems, hence lowering OPEX and CAPEX. It could also reduce the cost of pipelines since the heating or insulation is no longer needed while reducing operating pressure or increasing capacity.

Azarinezhad asserts in his report (Azarinezhad, 2008) that implementing this concept could also potentially reduce wax deposition issues by maintaining the fluid temperature for a longer time through exothermic hydrate formation reaction. An additional benefit of the HYDRAFLOW concept is that it could eliminate the need for a hydrate reactor. The subsea pipelines acts as the reactor producing hydrate in oil and/or water slurries.

The HYDRAFLOW cold flow concept is still under development.

5.4 Design and Economical Evaluation

The SINTEF-BP concept is chosen to be applied at Polarrev field development and analyzed in this case study. The NTNU cold flow concept is not discussed as an option due to a lot of similarities with the SINTEF-BP concept. The HYDRAFLOW cold flow concept is still under development. It has not been fully developed yet. That is the reason it is not considered as an alternative to avoid hydrate agglomeration in the pipeline in the current study case.

The SINTEF-BP Cold flow technology implemented at the Polarrev field development is meant to cover the entire field with one loop. The Polarrev field is not big, so only one reactor and one splitter with one recirculation loop is needed. The main 24” pipeline at Polarrev has the wall thickness of 0,0127 meters and the inner diameter of 0,5842 meters.

At the start of the wellstream a water separator placed downhole in every single production well. It requires 6 water separators at Polarrev field. These separators separate out the water, so after cooling and condensation no more than a certain amount of water remains in the wellstream. Usually it is about 10-20 percent of total wellstream volume.

Separated water will be used further for re-injection at analyzed field development. After water separation the wellstream is lead into the hydrate reaction part of the system.

A reactor is merely a continuous part of the uninsulated pipe. A reactor is placed right after the first template. There the hydrate particles in a cold stream enters the wellstream and are mixed in. These particles transform water in the wellstream into dry hydrate particles. All the water in the stream should be converted to hydrates in the reactor before it reaches the second template. Otherwise wet hydrates will occur, and it can result in agglomeration. The big challenge in SINTEF's concept is to guarantee that the hydrate remains dry and the water is quickly converted to hydrates. This is very difficult to guarantee.[1]

Then the cold wellstream together with the water converted into dry hydrate particles is lead to a splitter. In the splitter the cold wellstream and dry hydrate particles are separated. Non-recirculated hydrate particles in the wellstream are cooled down quickly to the ambient temperature of the Barents Sea since the pipeline is not insulated. It is done with the purpose to prevent condensation of water from liquid or gas hydrocarbon phases through the rest of the pipeline [23]. The non-recirculated particles together with the stream continue their journey towards the processing platform 200 km away where the dry hydrate particles must be separated out eventually. A separator at the processing platform is required for this purpose. The type of separation depends on the fluid system and density of the hydrate particles. Since this information is not relevant for the study case, the type of installed separator is not specified in the analysis. While some hydrate particles escape without being recirculated, the other part of the hydrate particles is subjected to recirculation and is sent back to the starting point of the reaction part of the system. A pump is needed to boost the recirculated stream.

The distance between templates and the splitter should be estimated in the early stage of a field development design in order to utilize this distance to cool down wellstream and to convert all the water to hydrates. The subsea layout of the Polarrev field has to be updated comparing to the layout that is presented in the initial description of the field in Chapter 4. The new modified layout of the subsea Polarrev field development using cold flow technology is illustrated on Figure 16.

[1] Personal communication with Senior Specialist Flow Assurance Keijo J. Kinnari, Statoil ASA, 19. May 2015

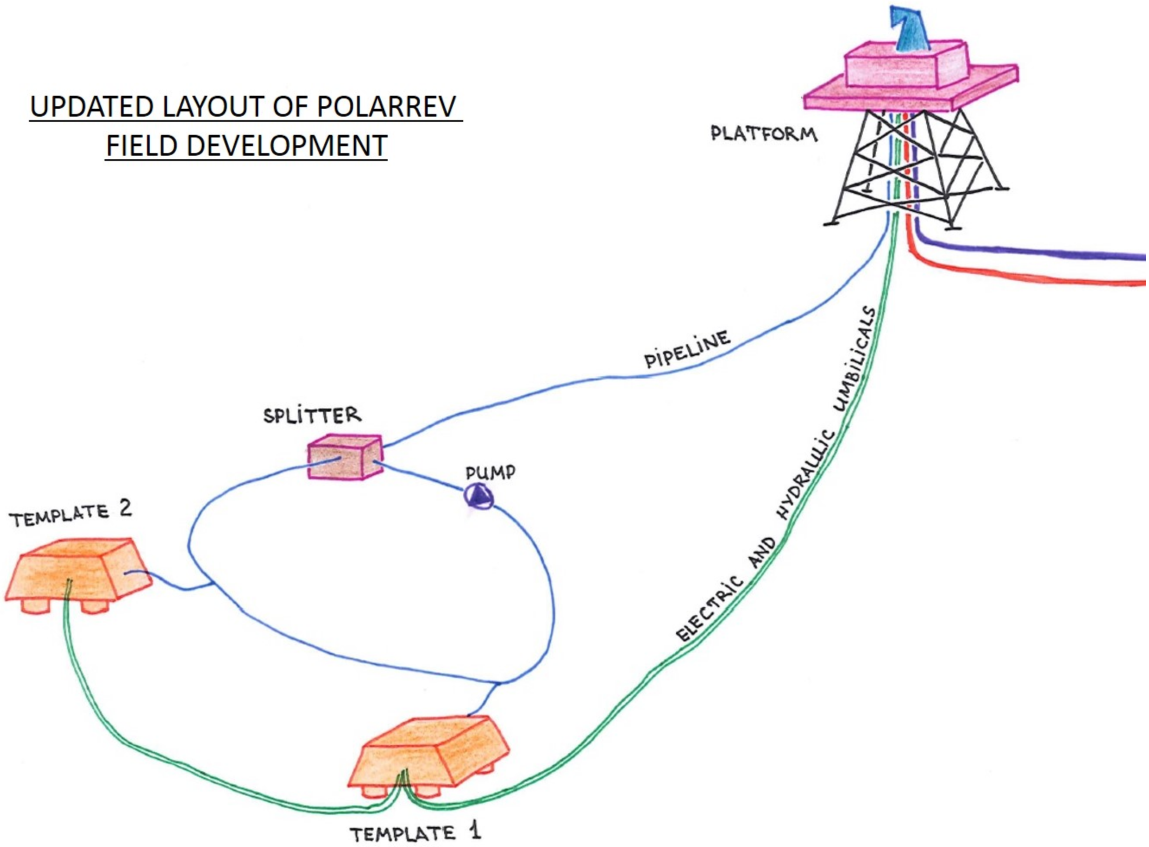

Figure 16. Updated layout of the Polarrev field development employing cold flow technology (made by author)

Production data for oil, gas and water are calculated in Chapter 4 and used to find parameters to estimate the distance required between the first and the second templates.

The cooling process described in this cold flow concept, is one of the engineering challenges. The cooling process is based on heat transfer from the pipeline to the surrounding it sea water and depends on the overall heat transfer coefficient (OHTC). OHTC has to be found to estimate the heat transfer. It obviously has lower value for coated or buried pipelines.

The value of the OHTC for bare pipe at seabed can be found from Figure 17. In Polarrev case, the OHTC of the 24” (0,6096 m) main pipeline is 100 W/m^{2}K.

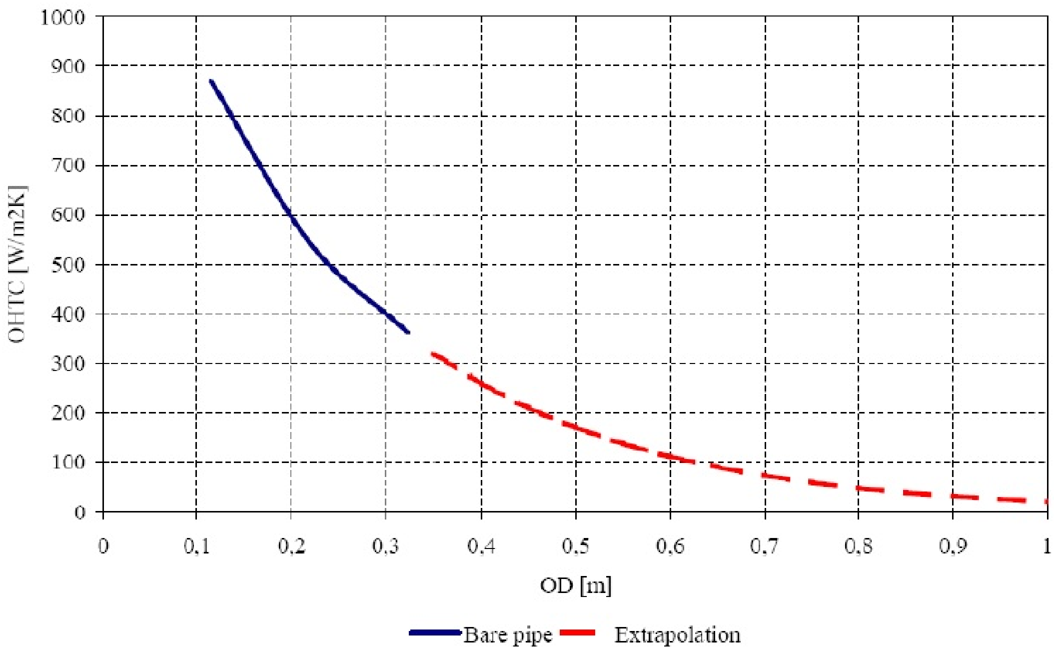

Figure 17. OHTC for bare pipes at seabed [17]

The obtained value of OHTC is relatively high according to the industry, where the value should usually be in the range of 15-20 W/m^2K [17]. SINTEF also used the OHTC equal to 100 W/m^2K in their research paper but the main pipe outer diameter was 0,225 m. These uncertainties regarding the OHTC have to be resolved. Despite of uncertainties about this coefficient, the obtained value of OHTC is used for further calculations.

The mass flow rate of oil, water and gas in the main pipeline at Polarrev applying cold flow technology is the same as the mass flow rate at subsea conditions that is calculated in Chapter 5 and summarized in Table 7. However, the mass flow rate of hydrates should be added to the total mass flow rate. The mass flow rate of hydrates is calculated considering the assumption about the hydrate composition. The hydrates entering the main pipeline are assumed to contain 87wt% water and 13wt% gas. The mass flow rate of hydrates as well as mass flow rate of oil, gas and water at subsea conditions are combines in Table 9.

Table 9. Mass rate of oil, water, gas and hydrates at subsea conditions in the main pipe

Mass rate of oil, kg/s	Mass rate of gas, kg/s	Mass rate of water, kg/s	Mass rate of hydrates, kg/s	Mass rate total, kg/s
0,46	28,34	0,20	0,23	29,23

To estimate if the system has excessive amount of gas or water, the mass fraction of oil, gas and water is found by applying Equation 5-1 [17].

$$x_{fr_i} = \frac{m_i}{m_{total}} \tag{5-1}$$

The mass fraction of oil is 0,016.

$$x_{fr_{oil}} = \frac{0{,}46}{29{,}23} = 0{,}016$$

The mass fraction of gas is 0,97.

$$x_{fr_{gas}} = \frac{28{,}34}{29{,}23} = 0{,}97$$

The mass fraction of water is 0,0068.

$$x_{fr_{water}} = \frac{0{,}20}{29{,}23} = 0{,}0068$$

The mass fraction of hydrates is 0,0079.

$$x_{fr_{hyd}} = \frac{0{,}23}{29{,}23} = 0{,}0079$$

The values of obtained mass fraction of the compounds are summarized in Table 10.

Table 10. Mass fraction of oil, gas, water and hydrates

Mass fraction of oil	Mass fraction of gas	Mass fraction of water	Mass fraction of hydrates
0,016	0,97	0,0068	0,0079

Analyzing the obtained results of mass fraction of the compounds, it can be concluded that the system have excess of gas. With the excess of gas it is very difficult to form hydrates with the assumed composition of 87wt% water and 13wt% gas. In this particular case the gas will take up all the water and, as the result, the hydrates will not form.

Although, the heat required to increase the temperature for the unit mass flow rate has to be calculated. The specific heat capacity of water is known and is equal to 4,186 kJ/kgK. The specific heat capacity of gas is assumed to be equal to the specific heat capacity of methane and it is 2,22 kJ/kgK. This assumption is made because of the composition of the gas in the wellstream at Polarrev containing 92% methane. According to Groisman (1985) the specific heat capacity of natural gas hydrates varies between 2,14 and 2,88 kJ/kgK for temperatures of 213-275 K [11]. The value of 2,75 kJ/kgK is assumed to be reasonable for the current case and is used as the hydrates specific heat capacity. The heat capacity of oil has to be calculated using Equation 5-2 [5].

$$C_{p,oil} = 2{,}96 - 1{,}34 \cdot \gamma_{oil} + T \cdot (0{,}00620 - 0{,}00234 \cdot \gamma_{oil}) \tag{5-2}$$

Where γ_{oil} – is the specific gravity of oil,

T – is the temperature of oil, K.

The specific gravity of oil is calculated in Chapter 4 and is equal to 0,88. The temperature of oil applied in Equation 5-2 is the temperature of oil at subsea conditions.

$$C_{p,oil} = 2{,}96 - 1{,}34 \cdot 0{,}88 + 323{,}15 \cdot (0{,}00620 - 0{,}00234 \cdot 0{,}88) = 3{,}11\ kJ/kgK$$

The specific heat capacity of oil is calculated and presented in Table 11 in combination with the heat capacity of gas, water and hydrates.

Table 11. Specific heat capacity of oil, gas, water and hydrates

Specific heat capacity of oil, kJ/kgK	Specific heat capacity of gas, kJ/kgK	Specific heat capacity of water, kJ/kgK	Specific heat capacity of hydrates, kJ/kgK
3,11	2,22	4,186	2,75

The temperature of the wellstream is not constant in the pipeline. When the wellstream flows in the pipeline, the temperature changes. Thus, the wellstream specific heat is an important parameter. Knowing the heat capacity of all compounds of the wellstream, the mixed specific heat capacity is calculated by Equation 5-3 [17].

$$C_{p,mix} = x_{fr_{oil}} \cdot C_{p,oil} + x_{fr_{gas}} \cdot C_{p,gas} + x_{fr_{water}} \cdot C_{p,water} + x_{fr_{hyd}} \cdot C_{p,hyd} \tag{5-3}$$

The specific heat capacity of hydrates is included in the Equation 5-3 since it is expected the immediate initiation of hydrates in the production pipeline. Thus, the mixed specific heat capacity of the wellstream is equal to 2,25 kJ/kgK.

$$C_{p,mix} = 0{,}016 \cdot 3{,}11 + 0{,}97 \cdot 2{,}22 + 0{,}0068 \cdot 4{,}186 + 0{,}0079 \cdot 2{,}75 = 2{,}25\ kJ/kgK$$

The hydration reaction is an exothermal reaction and it will be useful to remove the heat generated during the reaction in order to maintain the desired temperature conditions during the hydration. The increasing temperature during the hydrate reaction is found by Equation 5-4.

$$\Delta T = \frac{\Delta H}{m_{total} \cdot C_{p,mix}} \tag{5-4}$$

Where ΔH – is the enthalpy for hydrates, kJ/s

The enthalpy for gas hydrates is dependent on the mass flow of the hydrates and their heat capacity. Assuming that heat capacity of hydrates is 410 kJ/kg [17], the enthalpy for gas hydrates is calculated by Equation 5-5 and is equal to 94,3 kJ/s.

$$\Delta H = C_{hyd} \cdot m_{hyd} \tag{5-5}$$

$$\Delta H = 410 \cdot 0{,}23 = 94{,}3\ kJ/s$$

Thus, the increasing temperature during the hydrate reaction, is equal to 1,43℃.

$$\Delta T = \frac{94{,}3}{29{,}23 \cdot 2{,}25} = 1{,}43℃$$

The value of temperature difference is low due to low mass rate of hydrates causing the low value of enthalpy.

When the production starts, the hydrate slurry is already launched in the system. The temperature of that slurry is equal to the ambient sea temperature, 1°C. When the hydrate slurry joins the hydrocarbon fluid from the well having the temperature of 50°C, the temperature reduction occurs. The temperature is reduced to 25,5°C in the exposed pipe and the hydrocarbon fluid with hydrates flows towards the second template.

The bare pipe at the Polarrev field is exposed to the ambient sea temperature. The temperature changes with the length of the pipeline and is calculated applying Equation 5-6.

$$T_2 = T_{sea} + (T_1 - T_{sea}) \cdot \exp(\frac{-U \cdot \pi \cdot d \cdot L}{m_{total} \cdot C_{p,mix}}) \tag{5-6}$$

Where T_2 – is the outlet temperature, °C

T_{sea} – is the ambient sea temperature, °C

T_1 – is the summarized inlet temperature to the main pipe and the increased temperature due to hydrate formation

U – the overall heat transfer coefficient for the main pipe at Polarrev, W/m^{2}K

d – is the inner diameter of the main pipe, m

L – is the length of the pipe, m.

The ambient sea temperature varies between -2 and 4°C. For the calculation, the value of 1°C is used as the ambient sea temperature in the Barents Sea. The inlet temperature is the well fluid temperature reduced by hydrate slurry, 25,5°C. The increased temperature during the hydrate reaction is calculated and equal to 1,43°C. It is also assumed that the initiation of hydrates starts instantly. However, it is calculated in Chapter 6.1.1 of this report that the hydrate initiation temperature is 22°C. The temperature changer is calculated for different length of the pipe.

$$T_2 = 1 + (26{,}93 - 1) \cdot \exp(\frac{-100 \cdot \pi \cdot 0{,}5842 \cdot L}{29{,}23 \cdot 2{,}25})$$

The temperature changer for different length of the pipe is presented in Table 12.

Table 12. Temperature variation for different sections of pipeline

Length, m	Temperature, °C
0	26,93
200	15,84
400	9,50
600	5,86
800	3,78
1 000	2,59
1 200	1,91
1 400	1,52
1 600	1,30
1 800	1,17
2 000	1,10
2 200	1,06
2 400	1,03
2 600	1,02

Analyzing the obtained results, it can be concluded that the temperature decreasing as the length of the main pipe increases. The outlet temperature reduces by 40% already after 200 meters. The temperature will be equal to the ambient sea temperature after only about 1 400 meters. The dynamic of the changing temperature with the length of the pipe on the first loop is shown in the form of graph in Figure 18.

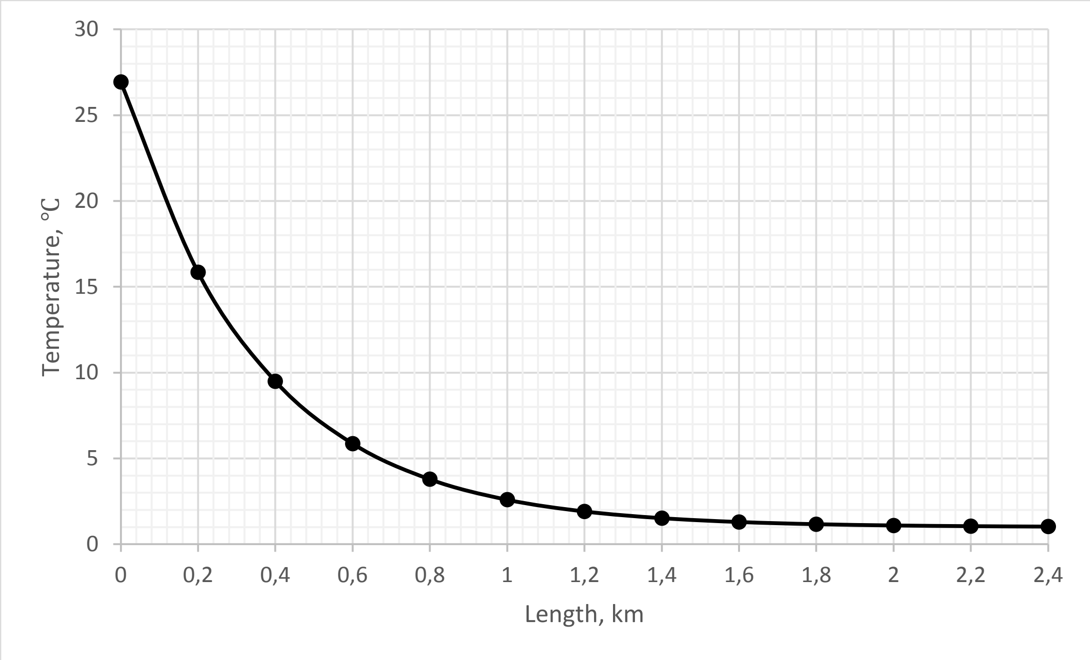

Figure 18. Change of the temperature with the length of the pipe on the first loop

All the water in the stream should be converted to hydrates before the second wellstream is introduced. It is calculated that the temperature is equal to the ambient sea temperature after about 1 400 meters. Since the hydrate formation temperature is 22℃, the conversion of the water starts already after about 100 meters. It is difficult to predict and has to be assumed that after 1 000 meters absolutely all the water in the stream from the first template is successfully converted to hydrates. The temperature in the pipeline at 1 000 meters is already 2,59 ℃. The fluid is cold enough. At that moment, the second stream can be introduced. So, the distance between the first and the second template is 1 000 meters.

Continuing on from the first mixing and hydrate formation, the cold stream grows in volume because of the newly converted hydrates. It is much easier for it now to handle the cooling and conversion at the second template where the new wellstream is introduced. The cold flow almost doubles its amount approaching the second template ensuring a shorter reaction zone for this template. The process of cooling and converting water to hydrates is similar as at the first template. Thus, after about 800 meters, all the water in the pipeline is converted to hydrates, and the temperature in the pipeline reaches the ambient temperature of the Barents Sea.

Thus, when the hydrocarbon fluid reaches the distance of 2 000 meters all the water from both wellstreams is assumed to be converted to hydrate particles. It should be done well before it reaches the splitter, where some of the cold hydrocarbon fluid together with dry hydrate particles are split off. It is very difficult to assure that absolutely all the water has converted to hydrates. It is expected to be based on experimentally observed kinetics for hydrate formation. In this case upscaling is a challenge since all the work on cold flow has been done so far only on small scale. Upscaling the results from small scale to large scale is always a challenge. The mass and heat transfer characteristics should be very well understood in order to do this in a predictive way. This is obviously not easy. Therefore, to assure that all the water has converted to hydrates, the results obtained from a test on large scale should be analyzed. Unfortunately, a large scale test unit does not exist[1].

After 2 000 meters when all the water is assumed to be converted, the hydrocarbon fluid finally reaches the splitter. Thus, the splitter is placed 2 000 meters away from the first template when the flow enters the main the pipeline.

It is assumed that in the splitter at Polarrev, 50% of the fluid with the large hydrate particles is recirculated to the starting point of the reactor system. While another 50% avoids the recirculation. The splitting off the hydrocarbon fluid in half ensures a basis for assumption that the recirculation pipe is half size of the main pipe, i.e. 12” is the size of the recirculation pipe. The pressure in this pipe is not high enough to transport the fluid. Thus, a subsea pump is required to boost the recirculating fluid. Eventually, the recirculating fluid enters the main pipeline and the wellstream from the first template, and newly added water starts to get converted to hydrates in the reactor. The process of converting to hydrates on the second loop is identical to the process described on the first loop. It continues over and over again.

When the production fluid with the dry hydrate particles reaches the processing platform, SINTEF suggests to separate the hydrates in a separator. In personal communication with Senior Specialist Flow Assurance Keijo J. Kinnari, Statoil ASA, it was concluded that the distance to the subsea facility is too far and thus, it is unnecessary to transport the hydrates after separation so far. Kinnari suggests to melt the hydrate slurry in the process instead. This requires extra energy but free water and natural gas will be back to the process stream. After all, the water is separated in regular manner. The amount of energy required to melt the hydrates at the end of production will result in increased operation expenditure at Polarrev.

The cost of power required for the field is an essential part of OPEX at the Polarrev field. Since employing the cold flow technology does not assure the total elimination of chemicals, the cost of the chemical additives required for hindering hydrate particles from agglomeration should be included in the calculation of OPEX. The SINTEF-BP concept says that the agglomeration of hydrates does not occur. However, the additives might be need anyway. The cost of this type of chemical additives are included in Chemicals in OPEX calculation as well as chemicals required for valve testing and chemicals required to protect against hydrates upstream the reactor and during shutdown and start-up situations.[1]

It is difficult to estimate the right value of OPEX because the work regarding cold flow concept has so far been done on small scale. Up to about 2,6 million USD have been spent on only developing the concept [34]. The value using as OPEX of employing cold flow concept at Polarrev is assumed based on the conclusion of BP after the calculation of OPEX. BP concluded that savings regarding OPEX were around 10 percent compared to the other solutions like LDHI and bundling [34]. The operational expenditure of employing cold flow technology at Polarrev is summarized and presented in Table 13.

Table 13. Calculation of OPEX of employing clod flow technology at Polarrev

Description	Cost	
	USD/day	USD/year
Power required	25 000	9 125 000
Chemicals added	5 000	1 825 000
Other operational expenditures	13 500	4 927 500
OPEX, USD		15 877 500

If the distance between the first template and the splitter is 2 000 meters, then the length of the recirculation pipe is also 2 000 meters. Thus, 2 000 meters is the extra length of the pipe that is required to be installed on the sea bottom for implementing the cold flow technology at the Polarrev field development. This parameter of CAPEX of implementing cold flow method will be higher comparing to the conventional technologies against gas hydrates. The cost of the reactor is estimated to be 15 million USD. The cost of the offshore pipeline is assumed to be 600 000 USD per kilometer. The cost of the splitter is assumed to be 1,5 million USD. While the cost of the subsea pump installed on the recirculation loop is assumed to be 3 million USD. Subsea separators installed in every production well to reduce the water content from the production stream expect to cost 3 million USD each. The capital expenditure of employing cold flow technology at Polarrev is summarized and presented in Table 14.

Table 14. Calculation of CAPEX of employing clod flow technology at Polarrev

Description	Cost per unit (cost per meter), USD	Unit number	Total cost, USD
Uninsulated pipeline	600	200 000	120 000 000
Extra uninsulated pipe	600	2 000	1 200 000
Reactor unit	15 000 000	1	15 000 000
Splitter	1 500 000	1	1 500 000
Subsea pump	3 000 000	1	3 000 000
Subsea separator	3 000 000	6	18 000 000
CAPEX, USD			158 700 000

5.5 Health, Safety and Environmental Aspect

The cold flow technology is considered to be an environmentally friendly solution against gas hydrates due to significant reduction of chemical solutions and injections. Although, some amount of chemicals and additives are still required to deal with wax, scale, asphaltenes, and prevent hydrate particles from agglomeration. Chemicals are also needed to protect against upstream the reactor and during shutdown and start-up situations. It is not fully proven yet that cold flow technology is able to eliminate these flow assurance issues. The possibility of harmful discharges to the sea is totally eliminated.

The risk of hydrate blockage to occur and cause the stop of production is fully obviated. Thereby, the potential personnel risk is eliminated.

Employing of the cold flow technology ensures low maintenance. In other words, only few people are required to perform maintenance work in the harsh environment of the Arctic. This fact increases safety of the implementing cold flow technology at the Polarrev field development.

5.6 Challenges in the Arctic

Employing cold flow technology in the arctic field developments is very challenging for many reasons. One of them is that this technology does not have proven track records. It has not been approved for installation yet. The technology is not proven and the industry does not have experience with it. Thus, there are always possibilities for failures that might not have been taken into account under development or have not been revealed under conducting the tests. Implementing new technology in the sensitive and remote environment of the Arctic is very hazardous. Concerning gas and oil production in harsh environment of the Arctic in the future, the industry will try to minimize the amount of offshore operations increasing thereby safety of the personnel. It will be difficult to achieve it with the newly installed technology which potentially may require improvement or elimination of defects on the field.

Initial target of the cold flow technology is oil fields with a certain amount of gas. What type of fields will be discovered in the Arctic is difficult to predict. It is challenging to plan if the cold flow can be implemented before determination of maximum GOR that will still allow effective transport of the slurry.

Floating icebergs and ice ridges is another challenge in the Arctic. Equipment installed on the sea bottom required for the effective transport of the slurry such as a reactor unit, a splitter, a subsea pump and separators has to be protected. Icebergs and ice ridges can damage the equipment causing the stop of production.

5.7 Summary: Cold Flow

Cold flow technology is a new innovative concept against gas hydrates. It is a simple technology that is initially developed with a goal to eliminate the need of chemical injection and heating of the pipeline. The technology is very simple: to achieve the absence of free water in the wellstream, free water has to be converted in to hydrates close to the production well. It has to be done in a controlled manner as well as fast so no water is available for further hydrate formation and thus no more solids will be able to deposit out. So cold flow technology is based on slurry transport of hydrate particles.

The concept of cold flow by SINTEF-BP that is employed at Polarrev in the case study, is not limited to a single well or template. It is implemented to produce a cold slurry from entire field where only one splitter and one recirculation loop is required.

Cold flow technology ensures flexibility in production rates. At Polarrev with the cold flow solution there is also the possibility for round-trip pigging from the platform. Employing this innovative method at the field does not limit the possibility of injecting chemicals if it is needed. Chemicals may be injected to avoid scales and asphaltenes. Cold flow technology is also meant to handle wax problem. The presented in the case study layout of the pipes allows fluid replacement of the entire pipeline volume. Employing of the cold flow technology ensures also low maintenance.

One of the main benefits for the cold flow technology is the ability to reduce pipe diameter because of eliminating voluminous chemicals. Thus, the diameter of the recirculation pipe at Polarrev is reduced. Cold flow technology at the Polarrev field development allows the usage of bare steel pipeline providing thereby cost savings regarding coating.

CAPEX at Porarrev is calculated to be acceptable due to the simplicity of the analyzed technology and reasonable amount of equipment required for its employment. OPEX is difficult to estimate due to lack of information. However, BP concluded that savings regarding OPEX were around 10 percent compared to the other solutions aimed to eliminate gas hydrates agglomeration.

At the discussed field where cold flow is successfully implemented, the length of the pipeline is 200 kilometers. However, cold flow technology has potentials for distance transfer greater than 200 kilometers from the wellhead to the processing facilities. Thus, for instance, as an alternative for the Polarrev field, the wellstream with the dry hydrate particles can be sent straight to onshore terminal. The production in this case becomes safer since people are removed from offshore operations. There is also a possibility for low cost tie-backs at already existing field developments.

Cold flow technology is considered to be an environmentally friendly solution because of significant reduction of chemicals. Although, some chemicals are still required to deal with the other flow assurance issues.

The disadvantage of the cold flow technology is that it can start being employed only when the stable operational conditions are established. That is why there is a need for the other hydrate preventing technologies during starts-up and shuts-in. Thus, the complexity of the system against hydrates and its total cost increases.

A brief summary of the employment the cold flow technology at Polarrev is presented in Table 15.

Table 15. Summarized description of employing cold flow technology at the Polarrev field

Parameter	Description
CAPEX	158 700 000
OPEX	15 877 500
HSE	Environmentally friendly
Challenges in the Arctic	• No experience • GOR • Icebergs and ridges can damage the equipment
Advantages of Cold flow	• Simple technology • Flexibility in production rate • Can handle wax problems • Low maintenance • No pipeline coating required • Reduced CAPEX • Reduced OPEX • Potential for distances greater than 200 km • Potential to eliminate surface-piercing structures • Reduced number of offshore personnel • Low cost tie-backs on existing fields • Can be mounted on existing infrastructures • No hydrate or wax blockage
Disadvantages of Cold flow	• No proven track-records • Extra amount of energy for melting hydrates • Not applicable during starts-up and shuts-in

6. Alternative Techniques to Prevent Gas Hydrate Formation

There are several alternative technologies to cold flow, orientated to achieve flow assurance and deal with the subsea transportation of wellstream challenges. They are evaluated as an option to be applied at the Polarrev field development.

It has been chosen to analyze and focus on two of them in the study case in this master thesis. These two particular technologies have good technological performance and proven track record or have potential for this. The selected technologies are:

- Injection of inhibitors: thermodynamic inhibitors (TI),
- Insulation and/or active heating: direct electrical heating (DEH).

This thesis focuses on analyzing each method with respect to its availability and applicability in the Arctic region, its economical aspect and environmental effect. The challenges that each method will face in the Arctic are also highlighted in the study case.

There are also other existing techniques to avoid gas hydrate initiation and agglomeration, such as water removal or dehydration, depressurization and injection of low-dosage hydrate inhibitors. Mechanical pigging is also counted as one of the possible options when the potential nucleation site for hydrate formation is removed. However, they are not analyzed in this report. Water removal is excluded from the study case because this method is impossible to implement in subsea environment. Injection of low-dosage hydrate inhibitors is not taken as a potential alternative to cold flow technology due to its toxicity. This type of inhibitors is prohibited to use on the Norwegian Continental Shelf.

6.1 Injection of Thermodynamic Inhibitors

Injection of thermodynamic inhibitors is commonly used when heating or dehydration the fluid is not possible or economically infeasible. It is often convenient to use in situations with subsea pipelines where other inhibitors e.g. corrosion inhibitors or scale inhibitors, are already routinely added. Thermodynamic inhibitors act as antifreeze.

Thermodynamic inhibitors are added into processing lines to inhibit the hydrate formation. Typically the injection of TIs is used for pipelines with length in the range from 10 km to 250 km.

To determine the optimum chemical treatment when hydrates are a concern, dozens of production parameters under both steady-state and transient operating conditions must be considered. Some of the most significant factors are: hydrate structure, subcooling, operating pressure and temperature, water composition (total dissolve solids) and water cut and the others.

Thermodynamic inhibitors have been used extensively in the oil and gas industry. The most commonly used are methanol, monoethylene glycol (MEG) or diethylene glycol (DEG). These are composites that lower the hydrate formation temperature and when they are mixed with water. By adding thermodynamic inhibitors, the hydrate equilibrium curve shifts to the left as it is shown on Figure 19, i.e. lower temperature and higher pressure are required to form hydrates. It changes the thermodynamic equilibrium of water and hydrocarbon molecules.

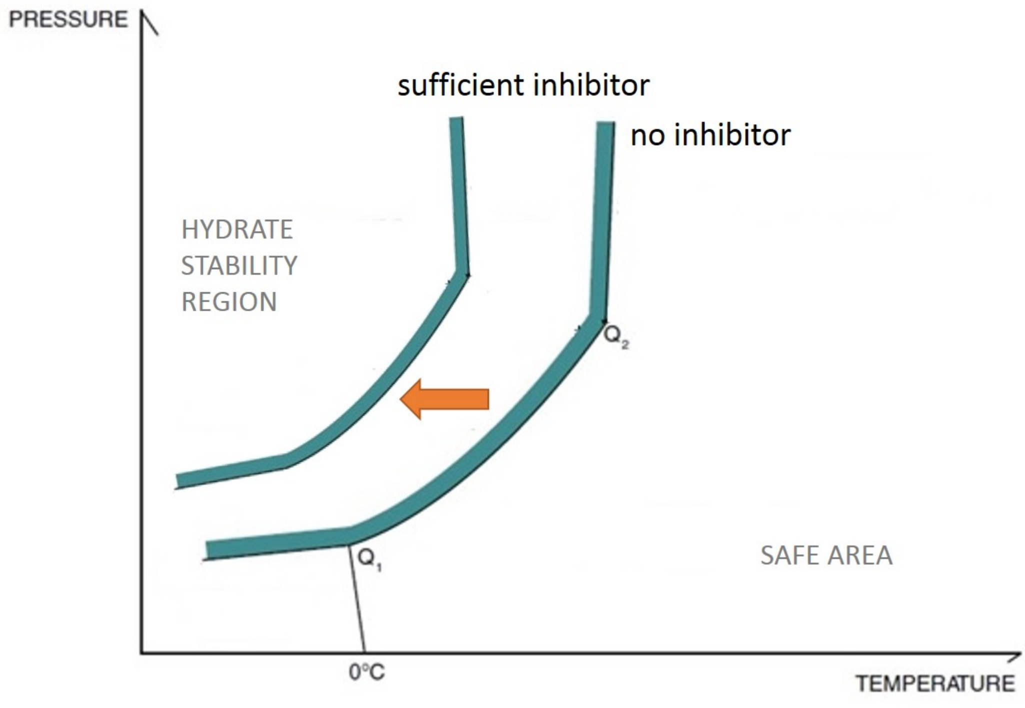

Figure 19. Shifting the hydrate equilibrium curve by adding thermodynamic inhibitors

Hence, it reduces the risk of hydrate formation. It is important to understand that thermodynamic inhibitors do not affect the initiation of hydrate crystals and the growth of crystals into blockage. They only alter the pressure and temperature conditions. Thereby shifting operating conditions out of the hydrate formation region [1].

TIs are typically used when the water cut in the system is in the range of 20 to 40 wt%, but theoretically it can be used at all water cuts. The subcooling effect can be up to about 30 ℃ for 50 wt% methanol at the pressure between 0 and 170 bar [34].

Methanol and MEG have been used both for inhibiting hydrate growth and for melting plugs. Methanol is widely used in the production pipelines because it is effective, available and has low cost, but it has its disadvantages. The issue with methanol and MEG is not only their relative low density: while most of the methanol dissolves in the water phase, a significant amount of methanol either goes to the vapor phase or dissolves into any liquid hydrocarbon phase present [31]. Because of this, the required quantities of methanol and MEG to be injected into the pipeline are often huge.

6.1.1 Design and Economical Evaluation

MEG is chosen for the case study as the thermodynamic inhibitor because it is safer and has become a more attractive alternative to methanol. It has been used extensively as thermodynamic inhibitor for the last decades because of its lower cost, lower viscosity and lower solubility in liquid hydrocarbons, and lower vapor pressure giving reduced gas-phases losses. That is the reason why MEG is chosen as a thermodynamic inhibitor in the study case about the field in the Arctic. Also, MEG decreases the risk of corrosion in the pipelines.

Another advantage of using MEG is that that type of inhibitor can be regenerated. It results in small losses. Conventional regeneration systems are normally used to boil off water at conditions close to atmospheric pressure. The operational temperature in regeneration system depends on the required lean MEG content. The MEG regeneration system is comprised of the below items [19]:

1. Lean and rich storage tanks,
2. Regeneration packages,
3. High pressure transferring pumps.

Each regeneration package consists of:

- Glycol flash drum,
- Rich glycol filter,
- Charcoal filter,
- Lean/rich exchanger,
- Distillation column,
- Reboiler,
- Condenser,
- Reflux drum.

A typical MEG-loop that is implemented at Polarrev is shown on Figure 20, where MEG comes with the wellstream and is separated out in the slug-catcher at the processing plant or platform and then regenerated so it can be re-injected into the wellstream.

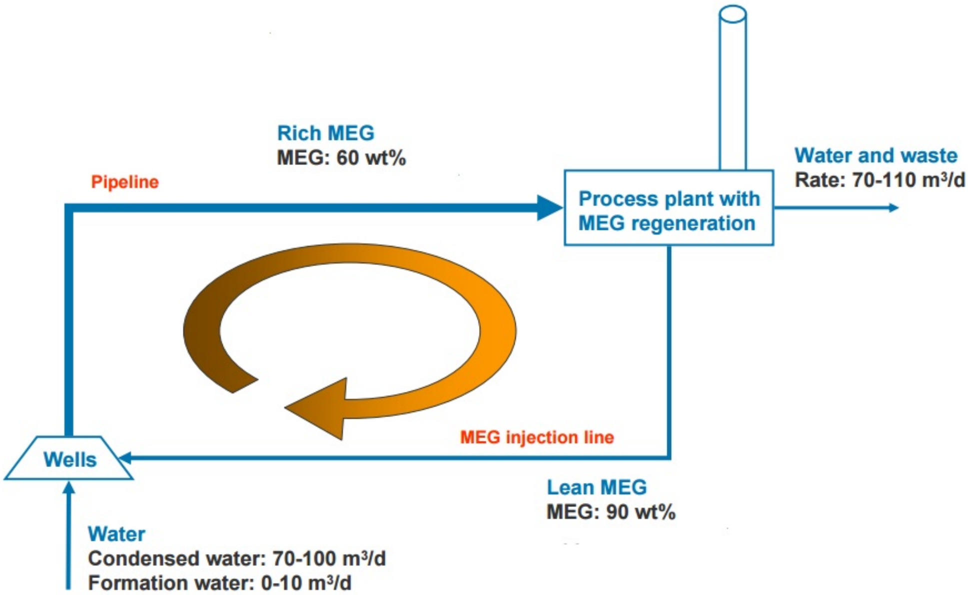

Figure 20. Typical simplified MEG loop [29]

It is decided that at Polarrev field development MEG is injected in the 4" pipelines. Several MEG storage tanks with several thousands of cubic meters are required. During an emergency shut-in and/or a production stop the fluids movement stagnates. It may cause suitable condition for hydrate formation. That is the reason it is chosen in this study case to inject a sufficient amount of MEG continuously. It will help to avoid the hydrate formation during unplanned shut-in situations at the field.

To be able to estimate OPEX regarding injection of thermodynamic inhibitors at the Polarrev field, the amount of inhibitor MEG required to prevent hydrates at the field during production phase has to be calculated. It is important to introduce properties of MEG. The properties that are most important for this study are listed in Table 16.

Table 16. Properties of MEG

Properties	Value
Empirical formula	$C_2H_6O_2$
Molar mass, g/mol	62.07
Boiling point, °C	198
Vapor pressure (at 20°C), kPa	0.011
Melting point, °C	-12.9
Density (at 20°C), kg/m^3	1 110
Solubility	soluble in most organic solvents
Viscosity (at 20°C), cP	16.9

Monoethylene glycol is the simplest of the glycol. It is often referred to just EG or MEG. Meg is the most widely used glycol due to its availability, cost and technical efficiency. MEG can be described as a clear, colourless, syrupy liquid with a sweet taste but no odour. MEG used in the study case assumed to have purity of 100%. Price of MEG is verified with the world's largest producer and supplier of petrochemicals Shell Chemical LP. On March 25, 2015 the MEG price is 0,5 USD/lb or 1,1 USD/kg.

$$\frac{0{,}5\ USD}{lb} = \frac{0{,}5\ USD}{1\ lb} \cdot \frac{1\ lb}{0{,}453592\ kg} = \frac{1{,}1\ USD}{kg}$$

The long distance to the processing platform brings a need for large amount of glycol injection. To calculate the amount of glycol required, the injection rate and storage capacity, HYSYS, an oil and gas process simulation software, is widely used in the industry to create a model of the field and perform simulations. Due to lack of access to this software, the calculation of amount of MEG required and the injection rate is conducted by using mathematical equations and assumptions.

Once the injection rate is established, the cost of inhibitor is estimated. The estimation of water content in the wellstream is an essential part of this calculation. It is calculated in Chapter 5 that the total amount of produced water at standard conditions is 518,4 m^3/day.

To calculate the amount of ethylene glycol that must be injected in order to prevent hydrates, a number of assumptions have to be made. One of them is that the gas together with the wellstream enters the pipeline at 5 500 kPa. The hydrate formation temperature of the gas is determined by using Baillie-Wichert chart method. In order to successfully apply this method it is assumed in Chapter 4 the presence of hydrogen sulfide 5 % and propane 3 %. Specific gravity of the gas is 0,75.

From the chart presented in Appendix 3, base temperature is 20,5°C, temperature correction is 1,5°C. The hydrate formation temperature is obtained by adding the temperature correction to the base temperature.

$$T_{hyd} = T_{base} + T_{cor} \tag{6-1}$$

Where T_{hyd} – is the hydrate formation temperature, °C
T_{base} – is the base temperature, °C
T_{cor} – is the temperature correction, °C.

$$T_{hyd} = 20{,}5 + 1{,}5 = 22\ °\mathrm{C}$$

The hydrate formation temperature for this study case is 22°C. In the transportation through the pipeline, the gas is assumed to cool down to 1°C, the ambient temperature of the Barents Sea. The required temperature depression is calculated:

$$\Delta T = T_{hyd} - T_{amb} \tag{6-2}$$

Where T_{amb} – is the ambient temperature at the Barents Sea, °C

$$\Delta T = 22 - 1 = 21°\mathrm{C}$$

A safety factor of 3°C has to be included in the calculations. Thus, the required temperature depression is 24°C.

The Hammerschmidt's empirical equation is used to estimate the amount of MEG required in the water phase to lower the hydrate formation temperature:

$$W = \frac{100 \cdot M \cdot \Delta T}{K_H + M \cdot \Delta T} \tag{6-3}$$

Where W – is the concentration of the inhibitor, wt%,
M – the molar mass of the inhibitor, g/mol,
ΔT – the temperature depression, °C,
K_H – a constant, depending on the type of inhibitor. For MEG is equal to 2 200 [25].

$$W = \frac{100 \cdot 62{,}07 \cdot 24}{2\ 200 + 62{,}07 \cdot 24} = 40{,}4\ wt\%$$

It is outside the range of applicability of the Hammerschmidt equation that is limited to concentrations of 30 wt% for ethylene glycol. The chart in Appendix 4 shows the values beyond this limit and is used to obtain the amount of MEG required to treat the water phase. The obtained value is 51 wt% which is both a better estimate and significantly larger. This value is used for the rest of the calculations.

The total amount of inhibitor required is equal to (1) the amount of inhibitor required to treat the water phase, plus (2) the amount of inhibitor lost to the vapor phase, and (3) the amount that is soluble in the hydrocarbon liquid. Glycols vaporization losses are generally very small and typically can be ignored [25]. Prediction of inhibitor losses to the hydrocarbon liquid phase is complicated. Usually, commercially available software programs that include proper calculation are used for this purpose. Due to lack of access to these software programs, the inhibitor losses to the hydrocarbon liquid phase is assumed to be 35% of the amount of ethylene glycol required to treat the water phase.

$$W_1 = 0{,}35 \cdot 51 = 17{,}85\ wt\%$$

Thus, the total amount of MEG required is calculated using Equation 6-4.

$$W_{total} = W + W_1 \tag{6-4}$$

$$W_{total} = 51 + 17{,}85 = 68{,}85\ wt\%$$

The production includes 518,4 m^3/day of water. 518,4 m^3 of water has a mass of about 518 400 kg. Therefore, to get a 68,85 wt% solution, based on water and ethylene glycol, Equation 6-5 is used. It requires the injection of $1{,}15\ \cdot 10^6$ kg/day of MEG.

$$i = \frac{W_{total} \cdot m_w}{(100 - W_{total})} \tag{6-5}$$

Where i – is the amount MEG required for injection, kg/day,

m_w – is the mass of water per day, kg/day.

$$i = \frac{68{,}85 \cdot 518\ 400}{(100 - 68{,}85)} = 1\ 145\ 806 \frac{kg}{day} = 1{,}15\ \cdot 10^6 \frac{kg}{day}$$

The inhibitor injection rate is calculated applying Equation 6-6. The density of MEG is 1 100 kg/m^3, so the inhibitor is injected at a rate of 1 045 m^3/day.

$$r = \frac{i}{\rho_{MEG}} \tag{6-6}$$

Where r – is the injection rate, m^3/day,

ρ_{MEG} – is the density of MEG, kg/m^3.

$$r = \frac{1{,}15 \cdot 10^6}{1\ 100} = 1\ 045\,\frac{m^3}{day}$$

Taking into account that the price of MEG is 1,1 USD/kg according to price change announcement from Shell Chemical LP, February 25, 2015, the cost of the MEG injection is calculated using Equation 6-7.

$$P = i \cdot p_{MEG} \tag{6-7}$$

Where P – is the total cost of the MEG injection, USD/day,

p_{MEG} – is the price of MEG per kilogram, USD/kg.

$$P = 1{,}15 \cdot 10^6 \cdot 1{,}1 = 1\ 265\ 000\ USD/day$$

$$P = 1\ 265\ 000 \cdot 365 = 461\ 725\ 000\ USD/year$$

Thus, to prevent hydrate formation at subsea field development Polarrev by injection of MEG, the cost of inhibitor exceeds 461 million USD every year. The MEG can be regenerated. However, not all the MEG can be regenerated, and new MEG will need to be added eventually. It is assumed that 3% of MEG every day has to be added additionally. The amount of new glycol that has to be added is 34 500 kg every day.

$$i_{new} = i \cdot 0{,}03 \tag{6-8}$$

$$i_{new} = i \cdot 0{,}03 = 34\ 500\ kg/day$$

Price for the new added MEG is calculated using equation 6-9 and is equal to 37 950 USD every day or about 14 million USD every year.

$$P_{new} = i_{new} \cdot p_{MEG} \tag{6-9}$$

$$P_{new} = 34\ 500 \cdot 1{,}1 = 37\ 950\ USD/day$$

$$P_{new} = 37\ 950 \cdot 365 = 13\ 851\ 750\ USD/year$$

It will result in increasing OPEX. Also, a large amount of heat is required to regenerate ethylene glycol. Since all the water has to be boiled out and this will lead to increased OPEX. The operational expenditure at Polarrev field development is calculated using the assumed value for heat required for regeneration and presented in Table 17.

Table 17. Calculation of OPEX of injection of thermodynamic inhibitor at Polarrev

Description	Cost	
	USD/day	USD/year
MEG for injection	1 265 000	461 725 000
MEG added	37 950	13 851 750
Heat for regeneration	5 000	1 825 000
OPEX, USD		477 401 750

The injection of MEG at Polarrev is associated with high CAPEX because of the equipment required for its regeneration. In addition to this, the cost of injection umbilical, high pressure transferring pump, several huge storage tanks should be included in the calculation of total expenditure. Two storage tanks, a rich MEG tank and a lean MEG tank, are required to be installed at the field. It is common to use insulated pipeline when the thermodynamic inhibitors are injected. The cost of thermally insulated pipe is assumed to be 1 000 USD per meter. Thus, the total cost of insulated pipeline is 200 million USD since the pipeline is 200 km long.

To calculate CAPEX at subsea field development Polarrev using injection of thermodynamic inhibitors, the price of the equipment required is assumed and listed in Table 18.

Table 18. Calculation of CAPEX of injection of thermodynamic inhibitor at Polarrev

Description	Cost per unit (cost per meter), USD	Unit number	Total cost, USD
Injection umbilical	400	200 000	80 000 000
Storage tank	10 000 000	2	20 000 000
Regeneration package	500 000 000	1	500 000 000
High pressure transferring pump	1 500 000	2	3 000 000
Insulated pipeline	1 000	200 000	200 000 000
CAPEX, USD			803 000 000

6.1.2 Health, Safety and Environmental Aspect

According to the Climate and Pollution Agency (CPA), MEG is classified as a green additive. Four different categories of chemicals are presented in Appendix 5. Offshore production allows MEG to be discharged with produced water into the sea as it is highly solvable in water.

Since MEG is classified as a green additive, it would seem acceptable in the case study to discharge it into the Barents Sea. However, there are some restrictions associated with the use of thermodynamic inhibitors that include environmental concerns based on the discharge limits and safety aspects. TIs are harmful to the environment in large quantities, thus significant disposal of them into the environment is not permitted.

The biggest drawback of MEG in the Polarrev case study is the large quantities required. The issue for ethylene glycol not its chemical characteristics, but the fact that the presence of large quantities can cause harm to the wildlife, fish and subsea plants [34].

Regeneration and disposal of MEG at Polarrev in the Arctic is an environmental issue. Ethylene glycol reclamation processes can generate a solid or a concentrated liquid waste product, which is mainly salt for disposal. These salts are toxic. The discharges contain mostly produced water. This water contains formation and condensed water. It may also contain regenerated injection water. It flows from the reservoir and is separated at the process facility. The main components of the produced water are dispersed oil, dissolve inorganic salts and organic components, low radioactive components, heavy metals, leftovers from added chemicals. Some operators purify the produced water before it is discharged into the sea.

In salt water biodegrading of MEG is much slower than in fresh water. It can take from 0,35 to 24 days for MEG to be readily degraded. Because of its biodegenerability MEG also increases risk to organisms for oxygen depletion in surface water [7]. A harmful contamination of the air will be reached rather slowly on evaporation of MEG at 20℃.

MEG is moderate toxic to humans. The biggest risk are related to coming in contact with large quantities as the skin quickly absorbs it. Ethylene glycol can be also absorbed into the body by inhalation. The substance irritates the eyes and the respiratory tract. The effect of being exposed to harmful amounts of MEG can be deep and rapidly induced sleep, breathing difficulties, kidney failure and brain injury. Exposure can cause lowering of consciousness. The long-term or repeated exposure affects the central nervous system, resulting in abnormal eye movements (nystagmus) [7].

6.1.3 Challenges in the Arctic

The biggest challenge of employing ethylene glycol, or thermodynamic inhibitors in general, in the areas of the Arctic is its large amount that is required for successful operation against gas hydrates.

According to Det Norske Veritas (DNV), TIs especially methanol, have a number of restrictions related to discharges even with regeneration equipment installed. Regeneration and disposal of thermodynamic inhibitors in moderate quantities can be harmful to the sensitive environment of the Arctic. After all, the discharges may contain dispersed oil, dissolve inorganic salts, low radioactive components, heavy metals and leftovers from added chemicals. The presence of large quantities of the chemicals in the Arctic is a threat to its ecosystem.

The discharges from thermodynamic inhibitors may not have immediate effect. However, long-term consequences can be severe. The Arctic is a very sensitive area to any kind of discharges. The level of pollution should be evaluated prior to installation of the production facilities. The authorities should reduce the allowed limit of discharges to the sea water of the Artic to its absolute minimum in order to protect the environment for the future generations.

6.1.4 Summary: Injection of Thermodynamic Inhibitors

The injection of thermodynamic inhibitors is a proven and efficient technology that is used in many filed developments all over the world. However, injecting MEG at Polarrev field development turned out to be a very costly solutions, primarily due to installation of the regeneration package required for the regeneration of MEG. The high amount of inhibitor required for injection also drags the final cost of technology up. However, cost per kilogram is low.

One of the advantages of injecting MEG is that this type of inhibitor decreases the risk of corrosion in the pipelines. MEG can be regenerated and use over and over again. Only small loses of inhibitor have been noticed. However, the regeneration package consisting of several types of equipment, is expensive. Also, the large amount of heat required to regenerate the calculated amount of ethylene glycol.

Ethylene glycol is highly solvable in water that is why offshore production allows MEG to be discharged with produced water into the sea. Though significant disposal of it into the environment is not permitted since it can harm wildlife, fish and subsea plants. MEG is moderate toxic to humans.

A brief summary of the injection of thermodynamic inhibitor, MEG, at Polarrev is presented in Table 19.

Table 19. Summarized description of employing injection of thermodynamic inhibitors at the Polarrev field

Parameter	Description
CAPEX	803 000 000
OPEX	477 401 750
HSE	Limited discharges, moderate toxic to humans
Challenges in the Arctic	• Large amount of discharges • Not immediate effect from discharges
Advantages of TIs: MEG	• Proven track-records • Effective technology • Well understood technology • Both oil and gas production • Can be used at all water cuts • Recoverable • Reduced risk of corrosion
Disadvantages of TIs: MEG	• High concentration required • Discharge limitations • Toxic in large amount • Large amount of heat required for regeneration • High CAPEX • High OPEX

6.2 Direct Electrical Heating

Another alternative to maintain pipeline operating conditions outside the hydrate stability zone that is analyzed in the study case about the Polarrev field is direct electrical heating. Direct electrical heating system is based on electric current that flows along the pipe wall causing direct heating of the pipeline using the pipe alternating current resistance. There are several types of DEH:

- Open Loop (wet-insulated),
- End-Fed Pipe-in-Pipe (dry-insulated),
- Center-Fed Pipe-in-Pipe (dry-insulated).

This thesis focuses only on Open Loop DEH system. This technique is based on using an alternating current to generate heat through a metallic conductor when two cables are connected to each end of the pipe creating a closed circuit. When current is added to the circuit, it will encounter an ohm force that creates loss of energy that will heat up the pipeline. The principle of DEH is shown on Figure 21.

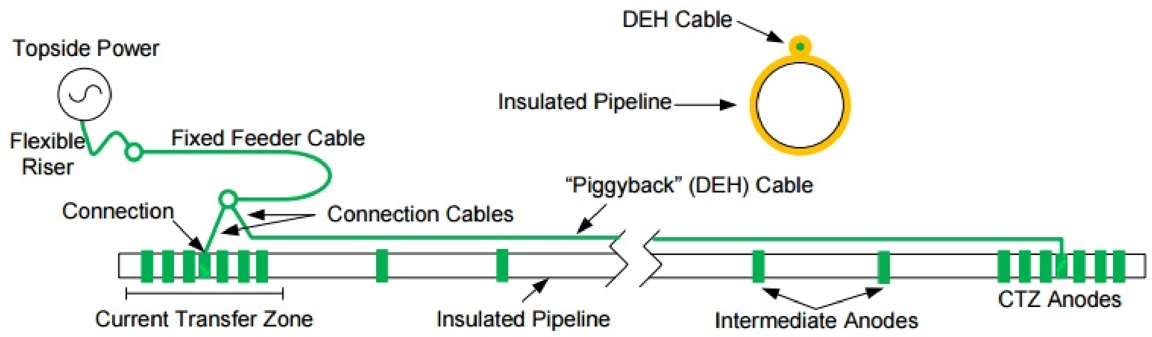

Figure 21. Working principle of DEH system [4]

The system is supplied with power from a power supply via two cables. One cable is connected to the closest end of the pipeline and the other is connected to the furthest end through a single core power cable ("piggyback" cable) that serves as the forward conductor. This cable runs parallel the pipeline and close to the pipeline. The pipeline is thermally insulated. The heating occurs through several intermediate anodes that are electrically connected i.e. earthed to surrounding water. The consequences of applying the open system is that the seawater acts as an electrical conductor being parallel to the pipeline i.e. the current is transferred by either the pipeline or through the water through the anodes in the current transfer zone. The transfer zone length has to be measured on full scale test directly on the pipeline. It reaches normally 50 m at 50Hz. The currents that leaves the individual anodes initially has a radial direction as shown on Figure 22.

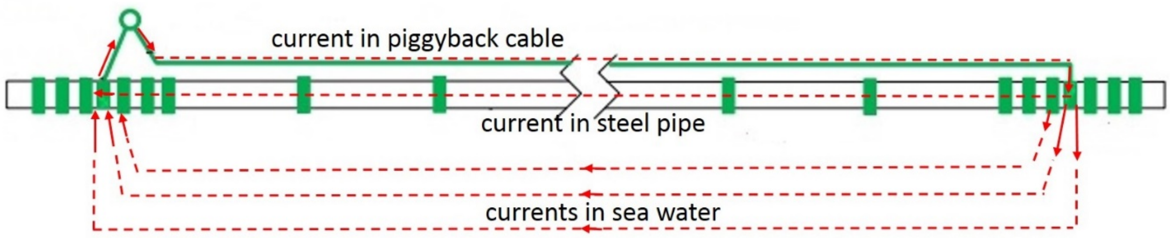

Figure 22. Electric current distribution in direct electrical heated pipe

The anodes have also a preventive role against corrosion [20]. Typically 30-40 % of the system current flows into the sea water.

Direct electrical heating has a proven track-record at the field development on Norwegian Continental Shelf. It has been successfully installed at such fields as Åsgard, Huldra, Kristin, Tyrihans and others.

It is worth mentioning that electrical heating is not always reasonable considering the pipelines that can be in hydrate formation zone hundreds of kilometers long. However, any stoppage in production for more than a couple of hours will allow the fluid to cool down into the hydrate stability zone. In these situations it will be hazardous to start up the production again.

6.2.1 Design and Economical Evaluation

Direct electrical heating is a very attractive alternative to conventional hydrate prevention techniques which provides heat directly to the pipeline by supplying electrical current in the pipe wall. Implementing this technique at Polarrev field will potentially provide high reliability and little adverse operational impact.

DEH suits best for pipelines with the diameter up to 30” and length up to 50 km and that operates in up to 800 m water depth. Obviously, regarding the case study the biggest challenge is distance of 200 km. Open Loop DEH technology is limited in length by the voltage rating of the piggyback cable. Some piggyback cable are qualified for over 100 kV. Power slip rings are available with ratings. So far the longest existing Open Loop DEH system is Tyrihans at 44 km, using 25 kV input voltage [9].

If a traditional design of DEH system is applied for the Polarrev field development, the voltage between the cable screen and the ground (sea water) will become too high due to the length of the cable which is 200 km. SINTEF recommends that the high screen voltage can be reduced by introducing sectionised heating. The simplest way is to connect the cable close to the mid-point of the cable [27]. Taking this into consideration, it is decided to introduce two mid-point connected sections in the study case as an option of DEH system as it is shown on Figure 23. In this case the pipeline is split into four identical sections. Each section is about 50 km long.

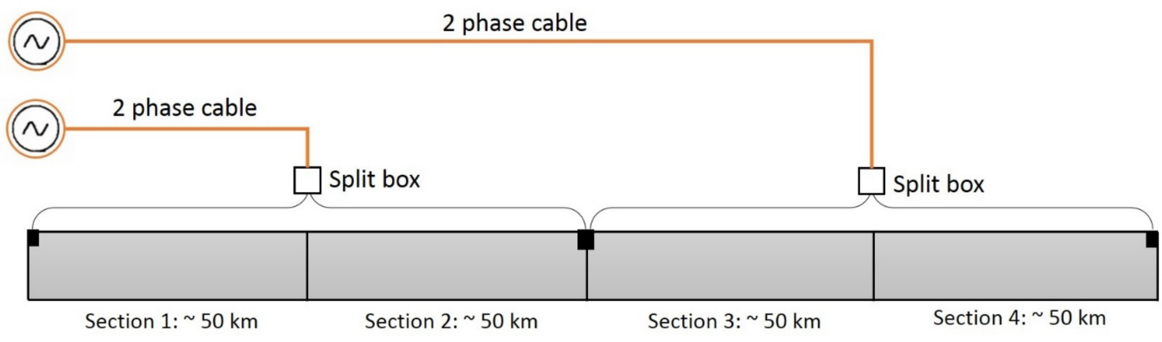

Figure 23. DEH system with two mid-point connected sections at the Polarrev field development

The advantage with this solution is that a conventional medium voltage cable design with a high resistance screen is applicable. The disadvantage with this solution is obviously additional cost of the extra feeder cable and extra connections to the pipeline including additional sacrificial anodes. Power losses are increased due to additional feeder cable. This causes higher power rating of the power supply system [27].

If the option with two mid-point connected sections is chosen for the field development in the current study case, it is evidently going to be a very expensive solution due to the large length of the pipeline. The length of the longest two-phase feeder cable should be then about 150 km which will bring additional costs described above. Thus, the DEH system with two mid-point connected sections is not an attractive solution for the Polarrev field development.

There is an alternative solution that has been considered as the most feasible solution for long pipelines that does not require additional feeder cables. Consequently, it has lower costs. Instead a cable with a semi-conductive outer sheath is used. By using a semi-conductive outer sheath, the charging current drains directly in to the sea continuously. This alternative eliminates the need for a metallic screen and charging current is conducted directly through the semi-conductive outer sheath to the seabed [27]. This design is chosen for the Polarrev field in the study case since it suits best for the long pipelines and in addition it has a proven track-record. The same type of cables is used for the Tyrihans field, where the longest DEH system is installed.

It is expected that implementing DEH will reduce CAPEX and OPEX at the Polarrev field investigated in the study case by eliminating the requirements for looped flowlines. Many of the capital and operational costs of chemical injection and handling equipment for the injection can be avoided by reducing the amount of chemicals required for the flowlines. At

Polarrev field there are production facilities that cannot be electrically heated, such as subsea trees and manifold. They still require chemical injection during shutdowns.

To estimate OPEX at Polarrev using DEH as the hydrate prevention technology, the amount of power required to heat 200 km long pipeline has to be calculated. Power consumption in the heating of pipelines varies with the size of a pipeline, pipeline insulation as well as requirements for the desired temperature. Power supply that is required to be above the critical temperature also depends on the thermal transfer coefficient, U. The value of the thermal transfer coefficient is often in the range of 3-7 W/m^2K for pipes with thermal insulation. Lower U-values may apply for buried flowlines. The higher the value of the thermal transfer coefficient is, the worse is insulation. In order to keep the fluid temperature over the critical temperature, power supply of about 70-160 W/m is needed. The efficiency of such a system is approximately 70%. It is about 10% loss in the seawater and 20% loss in the cable. The loss in the cable varies how close it is to the pipeline. The closer tube is, the smaller are losses.

There are two requirements for DEH system at Polarrev:

- Maintain the fluid temperature above 27℃,
- Be able to raise the temperature of the fluid from 1℃ up to over 27℃ within 48 hours.

The last requirement regards planned and unplanned reductions and requires more electricity than for the first one.

Prior to estimate the cost of DEH system at the Polarrev field, heat flow passing through a flowline has to be calculated. It is necessary to calculate the total thermal resistance of the flowline. Heat transfer resistance for each layer has to be calculated as well.

The 24” (0,6096 mm) flowline at Polarrev field development of supermartensitic stainless steel (13% Cr) has a wall thickness of 0,5” (0,0127 mm) and is insulated with 55 mm polypropylene coating. The cross section of the flowline is presented on Figure 24.

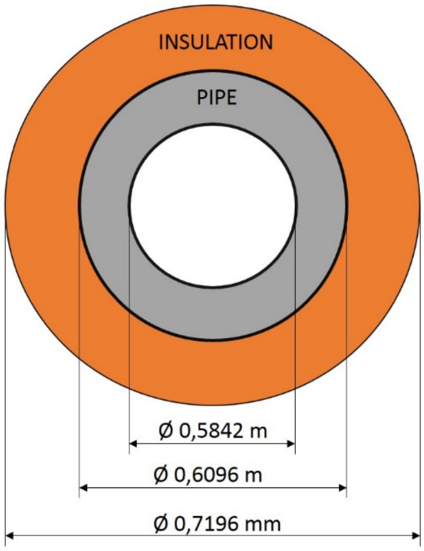

Figure 24. Cross-section of the flowline at the Polarrev field

Dimensions of the flowline are summarized in Table 20.

Table 20. Dimensions of the flowline at Polarrev

Description	Diameter, m	Radius, m
Pipe: inner	0,5842	0,2921
Pipe: outer = Insulation: inner	0,6096	0,3048
Insulation: outer	0,7196	0,3598

In addition to attached anodes in the end sections, the pipeline is equipped with anodes for cathodic protection purposes approximately every 500 m along the main route. The DEH system at the Polarrev field is supplied with power from the fixed platform installed 200 km south of the field. Consequently, the length of the flowline is 200 km.

The total thermal resistance of the flowline, R_{total}, with insulation layer and surface heat transfer resistance to inner production fluid and extern seawater, can be calculated with Equation 6-10.

$$R_{total} = \frac{R_i}{2\pi \cdot r_1} + \frac{\ln(\frac{r_2}{r_1})}{2\pi \cdot \lambda_{steel}} + \frac{\ln(\frac{r_3}{r_2})}{2\pi \cdot \lambda_{polyp}} + \frac{R_e}{2\pi \cdot r_3} \tag{6-10}$$

Where R_i – is the inner surface heat transfer resistance between fluid and material, m^2K/W,

R_e – is the outer surface heat transfer resistance between fluid and material, m^2K/W,

r_1 – is the inner radius of the pipe, m,

r_2 – is the outer radius of the pipe and the inner radius of the coating, m,

r_3 – is the outer radius of the coating, m,
λ_{steel} – is the thermal conductivity of steel, W/mK,
λ_{polyp}– is the thermal conductivity of polypropylene, W/mK.

The heat transfer resistance is calculated by using U-value and Equation 6-11.

$$R = \frac{1}{U_{-value}} \tag{6-11}$$

U-value for stainless steel is 1124 W/m^{2}K. Consequently, R_i is equal to 0,0009 m^{2}K/W. Steel has almost no resistance to heat transfer.

$$R_i = \frac{1}{1124} = 0{,}0009\ m^2K/W$$

U-value for coating material solid polypropylene is 2,84 W/m^{2}K. Consequently, R_i is equal to 0,3521 m^{2}K/W.

$$R_e = \frac{1}{2{,}84} = 0{,}3521\ m^2K/W$$

The thermal conductivity of stainless steel and polypropylene is 15 W/mK and 0,22 W/mK respectively.

So, the total thermal resistance of the flowline is calculated below and is equal 0,28 mK/W.

$$R_{total} = \frac{0{,}0009}{2\pi \cdot 0{,}2921} + \frac{\ln(\frac{0{,}3048}{0{,}2921})}{2\pi \cdot 15} + \frac{\ln(\frac{0{,}3598}{0{,}3048})}{2\pi \cdot 0{,}22} + \frac{0{,}3521}{2\pi \cdot 0{,}3598} = 0{,}28\ mK/W$$

To calculate the power supply for the DEH system, the equation 6-12 simplified is used:

$$\theta_1 = exp\left[\ln(\theta_2 - R_{total} \cdot P) - \frac{S}{R_{total} \cdot C}\right] + R_{total} \cdot P \tag{6-12}$$

Where θ_1 – is the temperature at the surface, °C,
θ_2 – is the temperature at subsea conditions, °C,
P – power supply, W/m,
S – is the length of a pipe, m,
C – heat capacity, J/kgK .

The Equation 6-12 is transformed to find the required power supply.

$$P = \frac{-\theta_1 + \theta_2 \cdot \exp(\frac{-S}{R_{total} \cdot C})}{R_{total} \cdot \exp\left(\frac{-S}{R_{total} \cdot C}\right) - R_{total}} \tag{6-13}$$

The temperature at subsea conditions is assumed to be 50℃ and at the surface it is assumed to be 27℃. Heat capacity for gas is 2 500 J/kgK. The value of heat capacity is obtained by using the heat capacity chart for natural gas with assumed in Chapter 4 relative density 0,75. The chart is presented in Appendix 6.

$$P = \frac{-27 + 50 \cdot \exp(\frac{-200\ 000}{0{,}28 \cdot 2500})}{0{,}35 \cdot \exp\left(\frac{-200\ 000}{0{,}28 \cdot 2500}\right) - 0{,}28} = 96{,}4\ W/m$$

The obtained value of power supply at the Polarrev field is relatively low compared to the required power supply at the Kristin field, which is equal to 156 W/m. The main reason of such a difference is insulation material, its properties. The U-value for the coating at Polarrev is quite low, meaning low heat loss. It causes higher thermal resistance and, hence, lower required power supply.

Power required to supply the whole DEH system is calculated using Equation 6-14 and is equal to 19,28 MW. For long pipeline, high power consumption is required.

$$P_{total} = P \cdot S \tag{6-14}$$

Where P_{total} – is the total required power to supply the DEH system, W,
S – is the length of the pipeline, m.

$$P_{total} = 96{,}4\ \cdot 200\ 000 = 19\ 280\ 000\ W$$

Operational costs, OPEX, will depend on how much the DEH system will be in use. If it is used all the time to maintain the production fluid temperature above 27℃, then the cost will turn out to be enormous. For long pipelines (500 km) and during tail production it is highly recommended to apply continuous heating [21]. As an option for shorter distances the DEH system can be used only during planned as well as unplanned shutdowns. In this case, the operator should focus on having as few shutdowns as possible to reduce the OPEX of the DEH system. It is assumed that the DEH system at Polarrev will be used in total 3 weeks per year. Price for power used in DEH system is difficult to estimate. However, 1 NOK/kWh is assumed to be reasonable for DEH projects on Norwegian Continental Shelf. In this case the cost will be more than 9 million NOK per year.

$$P = \frac{3 \cdot 7 \cdot 24\ hours}{year} \cdot \frac{1\ NOK}{kW \cdot hours} \cdot 19\ 280\ kW = 9\ 717\ 120\ NOK/year$$

Converting the obtained value in to USD/year using the currency rate 1 NOK = 0,13 USD from 08 May 2015, the cost of power required at the field is more than 1 million USD per year.

$$P = 9\ 717\ 120\ \cdot 0{,}13 = 1\ 263\ 226\ USD/year$$

If direct electrical system technology is decided to be used only during shutdowns, assumed 3 weeks per year, then another alternative to prevent hydrate initiation and agglomeration has to be used for the rest of the time. The final OPEX at Polarrev in this case will depend on the chosen method to tackle the gas hydrates.

However, if DEH system is in use continuously at Polarrev in the case study, the cost of the power required will be about 22 million USD per year. This value is used in OPEX calculation for comparison with the cold flow technology.

$$P = \frac{365 \cdot 24\ hours}{year} \cdot \frac{1\ NOK}{kW \cdot hours} \cdot 19\ 280\ kW = 168\ 892\ 800\ NOK/year$$

$$P = 168\ 892\ 800 \cdot 0{,}13 = 21\ 956\ 064\ USD/year$$

OPEX of utilizing direct electrical heating continuously at the Polarrev field as the method against gas hydrates is presented in Table 21.

Table 21. Calculation of OPEX of direct electrical heating installed at Polarrev

Description	Cost	
	USD/day	USD/year
Power	60 154	21 956 064
OPEX, USD		21 956 064

It goes without saying that CAPEX of employing DEH system at Polarrev depends mainly on the length of the flowline. Investment costs of DEH at Polarrev are expected to be 6 000 000 NOK/km [28]. Thus, for the full length of the flowline, investment costs will be 1,2 billion NOK or 156 million USD.

$$IC = 6\,000\,000 \cdot 200 = 1\,200\,000\,000\ NOK$$

$$IC = 1\,200\,000\,000\ \cdot 0{,}13 = 156\,000\,000\ USD$$

On top of that the cost of insulated pipeline should be added. The cost of thermally insulated pipeline is assumed to be the same as for the injection of MEG, 1 000 USD per meter. Thus, the total cost of insulated pipeline is 200 million USD since the pipeline is 200 km long. CAPEX of installed at Polarrev DEH system is calculated in Table 22.

Table 22. Calculation of CAPEX of direct electrical heating installed at Polarrev

Description	Cost per unit (cost per meter), USD	Unit number	Total cost, USD
Investment cost	780	200 000	156 000 000
Insulated pipeline	1 000	200 000	200 000 000
CAPEX, USD			356 000 000

It should be mentioned that the DEH system has quite low maintenance cost which also should be included in the estimation of the final total cost of the DEH system at the field.

One of the advantages of DEH system is that it can also handle most of the flow assurance problems, such as wax, scale and the others. It is profitable to use direct electrical heating in case long shutdown periods leading to the initiation of hydrate plugs. The system provides heating following by melting of the formed plug and eliminating of blockage.

6.2.2 Health, Safety and Environmental Aspect

It can be dangerous using DEH at Polarrev without a protection system in case of a fault (earth fault) in the power. If the fault is not cleared in due time, the heat generated at the fault location may damage the 24" pipeline itself causing severe violation on the integrity of the production system [27]. Also, small cracks in the pipeline's insulation may cause undesirable current into the sea as well as corrosion. This possible issue should be taken into account prior to installation of the DEH system at the Polarrev field. Certain mitigation measures must be performed.

DEH is considered to be an environmentally friendly technology due to absence of chemical injection and harmful discharge. Electricity used to heat the flowline at Polarrev comes from power station installed on the processing platform 200 km away from the subsea installation.

The most common emissions associated with a power plant are carbon dioxide (CO_2), nitrogen oxides (NO_x), methane (CH_4) and volatile organic compounds (VOC). All these emissions lead to different levels of air contamination.

Carbon dioxide is the most important greenhouse gas. The greenhouse effect can lead to changes in the climate of the planet. Some of these changes might include temperature extremes, higher sea levels, changes in forest composition, and damage to land near the coast. Human health might be affected by diseases that are related to temperature or by damage to land and water.

Nitrogen oxides are formed mainly by the combustion of fossil fuels. The amount of nitrogen oxides emissions depends on both the combustion technology and the amount of used fuel. Nitrogen oxides emissions can harm plants and animals by acidification of reservoirs and soil, stones and metals as a result of acid rain. When large amount of nitrogen oxides in combination with VOC is exposed to solar radiation, tropospheric ozone will form. Tropospheric ozone causes health damage as well as damage to growing crops and buildings.

Volatile organic compounds emissions lead to a variety of environmental impacts. As it is mentioned before, together with NO_x it forms tropospheric ozone. VOC can damage respiratory tract by being directly exposed. When VOC reacts with air in the atmosphere, it gives an indirect contribution to the greenhouse effect by forming ozone and CO_2.

6.2.3 Challenges in the Arctic

There are a lot of challenges the direct electrical heating technology has to face in the harsh Arctic environment. At Polarrev in relative shallow water of the Barents Sea the pipeline and DEH cable must be buried at least first 100 meters towards the processing platform. It must be done to protect the pipeline with attached to it DEH cable from floating icebergs and ice ridges. Burying the pipeline will also decrease heat loss causing higher thermal resistance and, hence, lower required power supply.

One of the main challenges of employing DEH system at the fields in the Arctic is long pipelines. Arctic is the remote area. The land further north is not suitable for construction of terminals or processing plants. Thus, long flowlines stretched for several hundred kilometers are expected to connect production wells with processing platforms, terminals onshore or, possibly, FPSO there in the future. Employing direct electrical heating on those long distance flowlines will be a particularly costly due to amount of energy required to warm a pipeline of several hundred kilometers long. Moreover, for long pipelines it is highly recommended to apply continuous heating resulting in unacceptably high OPEX.

Fault in the power as well as small cracks in the pipeline's insulation will require reparation. Performing any offshore operations in the Arctic is very challenging. Operational window is very short in the Arctic due to weather conditions. The operation can be aborted anytime if the weather is not acceptable and it is considered risky to conduct it. At the same time, long waiting period can be crucial for the subsea production on long distances.

6.2.4 Summary: Direct Electrical Heating

Direct electrical heating is simple and well understood technology. In the Polarrev case study it is chosen to use a cable with a semi-conductive outer sheath instead of the additional feeder cables. This solution is considered as the most feasible solution for long pipelines. However, some subsea production facilities at Polarrev, such as subsea trees and manifolds cannot be electrically heated. They still require chemical injection during shutdowns.

DEH is a reliable and proven technology against hydrates but it turned out to be expensive and not economically feasible for long subsea pipelines. This technology is considered more suitable for shorter pipelines of a distance of a few kilometers and should be definitely considered as a profitable solution to avoid hydrates. Thus, for instance, on the Tyrihans oil and gas field in the Norwegian Sea, Statoil together with partners saved 1 billion NOK by installing a pipeline that could be heated electrically [32]. However, at Polarev CAPEX of implementing direct electrical heating is high due to high investment cost and insulation required. OPEX turns out to be too high as well due to large amount of power required to supply the 200 km long DEH system in case this technology is utilized continuously. As an option, the DEH system can be used only during shutdowns combining another method to avoid hydrates that is applied continuously. The cost of DEH system in this case acceptable. The final cost depends on the chosen method. In case if DEH system is in use continuously at Polarrev, the cost of the power required will be about 22 million USD per year. That amount paid every year during production, is not acceptable. Even if the DEH system has quite low maintenance cost that makes it one of the attractive solutions for shorter pipelines.

The DEH system can also handle wax, scale and the other flow assurance problems at the Polarrev field. It can also provide melting of the formed hydrate plugs and eliminate the blockage.

DEH is considered to be an environmentally friendly technology due to absence of chemical injection and harmful discharge. However, the electricity to heat the Polarrev's flowlines comes from the power station. It requires 19,28 MW of power from the power station. The number is enormous and will lead to large amount of CO_2 and CH_4 emissions and different levels of air contamination.

A brief summary of employing direct electrical heating at Polarrev is presented in Table 23.

Table 23. Summarized description of employing DEH at the Polarrev field

Parameter	Description
CAPEX	356 000 000
OPEX	21 956 064
HSE	Environmentally friendly, but emissions from the power station
Challenges in the Arctic	• Long distances • Icebergs and ridges can damage the pipeline • Short operational window in case of damage
Advantages of DEH	• Proven technology on short distances • Simple and well understood technology • Both oil and gas production • Can be use only during shutdowns • Low maintenance • Can also handle wax and scale • Melt the formed plugs
Disadvantages of DEH	• Chemical injection required partly • High CAPEX • High OPEX due to long distance • Cable failure can cause damage to the pipeline

Discussion

Three techniques to tackle gas hydrates – cold flow, injection of thermodynamic inhibitor, direct electrical heating – have been applied at the Polarrev field development in the Arctic and evaluated based on capital and operational expenditure, environment impact, challenges each of the methods has to face in the harsh environment of the Arctic. A comparison table summarizes the performed analysis including advantages and disadvantages of every analyzed in the case study method.

Table 24. Three techniques to prevent gas hydrates at Polarrev: a comparison table

	Cold flow	Injection of thermodynamic inhibitors: MEG	Direct electrical heating
CAPEX	158 700 000	803 000 000	356 000 000
OPEX	15 877 500	477 401 750	21 956 064
HSE	Environmentally friendly	Limited discharges, moderate toxic to humans	Environmentally friendly, but emissions from the power station
Challenges in the Arctic	• No experience • GOR • Icebergs and ridges can damage the equipment	• Large amount of discharges • Not immediate effect from discharges	• Long distances • Icebergs and ridges can damage the pipeline • Short operational window in case of damage
Advantages	• Simple technology • Flexibility in production rate • Can handle wax problems • Low maintenance • No pipeline coating required • Reduced CAPEX • Reduced OPEX • Potential for distances greater than 200 km • Potential to eliminate surface-piercing structures • Reduced number of offshore personnel • Low cost tie-backs on existing fields • Can be mounted on existing infrastructures • No hydrate or wax blockage	• Proven track-records • Well understood technology • Effective technology • Both oil and gas production • Can be used at all water cuts • Recoverable • Reduced risk of corrosion	• Proven technology on short distances • Simple and well understood technology • Both oil and gas production • Can be use only during shutdowns • Low maintenance • Can also handle wax and scale • Melt the formed plugs
Disadvantages	• No proven track-records • Extra amount of energy for melting hydrates • Not applicable during starts-up and shuts-in	• High concentration required • Discharge limitations • Toxic in large amount • Large amount of heat required for regeneration • High CAPEX • High OPEX	• Chemical injection required partly • High CAPEX • High OPEX due to long distance • Cable failure can cause damage to the pipeline

The cost of employment of these hydrate preventing methods varies. CAPEX of injection of MEG at Polarrev is the highest due to installation of the costly equipment. Regeneration package utilized for regeneration of MEG constitutes the largest part of CAPEX independent of the amount of chemicals required. While capital expenditure of employment of DEH system depends mainly on the length of the pipeline. In the Polarrev case the production pipeline is long. It results in high investment cost and high cost for insulation. Both are calculated per kilometer of length. Installation of the cold flow technology does not envisage high-priced equipment. Moreover, utilizing uninsulated pipeline results in savings on pipeline insulation despite of longer pipeline required for a recirculation loop.

Choosing injection of ethylene glycol at Polarrev as the method to avoid hydrates will also be characterized by high operational expenditure. The main reason of high operational cost is obviously large amount of chemicals required to inject to deal with gas hydrates. OPEX of injection of MEG is significantly higher than OPEX of cold flow and DEH system at Polarrev.

Estimating the right value of OPEX of employing the cold flow technology is a challenge since the research regarding the cold flow concept has been only performed on small scale. Although, cost of developing the concept is relatively high. The value of OPEX presented in the case study is based on the BP’s conclusion that savings regarding operational expenditure of the cold flow technology are about 10 percent in comparison with the other solutions like LDHI and bundling. The significant part of OPEX of both the cold flow and the direct electrical heating comprises power cost. However, power required to heat the pipeline of length of 200 kilometers is much higher than power consumption by cold flow technology.

It is worth mentioning that while analyzing DEH system at Polarrev, it is chosen to apply the heating continuously over the 200 kilometers long pipe. Obviously, it is the main reason of high OPEX. As an alternative, direct electrical heating can be applied only during shutdowns in combination with the other hydrate prevention techniques in the daily production. In this case the value of OPEX will depend on the chosen method. This option is not presented as the alternative to deal with gas hydrates initiation and agglomeration in the Polarrev case study.

Environmental impact of each of the discussed methods is an important parameter in comparison analysis. Arctic ecosystems are extremely sensitive to discharges and emissions, especially from the gas and oil industry. Injection of thermodynamic inhibitors has a poor environmental performance comparing with two others methods. TIs are harmful to the environment in large quantities, thus significant disposal of them into the environment is not permitted on Norwegian Continental Shelf. In contrast to it, both the cold flow technology and DEH are considered environmentally friendly due to significant reduction of chemical injections and absence of harmful discharges. However, electricity used to heat the flowline comes from the power station producing emissions that can lead to different levels of air contamination.

The cold flow technology has a number of advantages compared to the other two methods analyzed in the case study. First of all, the technology is very simple and is not limited by a production rate. It is characterized by low maintenance required and reduction of offshore personnel. Although DEH is also distinguished by low maintenance. One of the advantages of employing cold flow is the opportunity to utilize insulated pipe, while both injection of TIs and DEH require pipe insulation. However, an extra pipeline is required for a recirculation loop in the cold flow system. The cold flow technology can potentially be applied on long distance pipelines while injection of chemicals and DEH systems are limited in distances.

Tests conducted by SINTEF-BP showed that cold flow can significantly reduce wax formation. SINTEF-BP is not worried about the asphaltenes or scale either. However, it is not officially proven. DEH system can also handle most of the flow assurance problems, such as wax, scale and the others. Injection of inhibitors preventing hydrates requires though injection of chemicals against wax, scale, etc. in addition.

One of the main disadvantages of the cold flow technology is that it has not been installed yet. Hence, it does not have any proven track records. While both injection of thermodynamic inhibitors and direct electrical heating has been proven to be effective and been successfully used on the Norwegian Continental Shelf.

Cold flow is still under development. There are still some technical challenges that has to be overcome before successful implementation on the field. One of them is upscaling. So far all the work and tests on cold flow has been done only on small scale. Upscaling the results from small scale to large scale is always a challenge. It is essential to ensure that no free water passes the splitter and continue to flow in the main pipe causing hydrate formation. In order to be assured that absolutely all the water has converted to hydrates before it is lead to the splitter, the mass and heat transfer characteristics should be very well understood to be able to do this in a predictive way. This is clearly not easy. Therefore, to assure that all the water has converted to hydrates, the results obtained from a test on large scale should be analyzed. Unfortunately, a large scale test unit does not exist.

Employing the cold flow technology does not assure the total elimination of chemicals. Chemical additives are required for hindering hydrate particles from agglomeration as well as for valve testing and to protect against hydrates upstream the reactor and during shutdown and start-up situations. Also, chemicals might be needed to eliminate other flow assurance issues than hydrates. The initial purpose of cold flow technology was total elimination of chemicals. If the cold flow concept requires the use of chemicals then it failed its initial goal.

Conclusion

Comparing in this master thesis the innovative technology against gas hydrates – cold flow – with some of the conventional technologies, namely injection of thermodynamic inhibitors and direct electrical heating by applying these techniques to the imaginary field development in the Arctic, the optimal solution to tackle hydrates in the Arctic region has been revealed. The comparison is based on analyzing economical evaluation of each hydrate preventing method, as well as their environmental performance and challenges each of them has to face in the harsh environment of the Arctic.

The cold flow technology turned out to be the most cost effective solution in the Arctic comparing to the other methods to tackle hydrates analyzed in the thesis. While hydrate inhibition with constant injection of chemicals combined with insulated pipelines remains a high-cost solution.

The cold flow method is also environmentally friendly what is significantly important for the sensitive arctic ecosystems. There in the Arctic will be zero tolerance for spills and system and execution integrity will be critical. The most significant aspects from environmental perspective, are that surface-piercing structures can be eliminated through enabling direct subsea production to onshore terminal. Hence, the production becomes safer since people are eliminated from offshore operations.

Unlike the injection of chemicals and DEH, the cold flow technology can operate in long distances. That is beneficial in the Arctic where the infrastructure is completely absent or undeveloped. The cold flow technology allows to use longer satellite tie-backs at lower cost using uninsulated steel pipelines. However, there are concerns about cold flow concept flexibility regarding dealing with different petroleum at different conditions. SINTEF asserts that the variation in viscosity will be a limitation on transport over long distances.

Employing cold flow technology, according to SINTEF-BP concept, enables to give an opportunity to avoid also the other flow assurance issues, namely wax, asphaltenes, scale. Neither injection of inhibitors or employing direct electrical heating give the same opportunity. However, there is no sufficient evidence proving that wax will not be a problem. Test regarding scaling have been positive but not conclusive. No test has been conducted regarding asphaltenes but it is believed by the founders that they will not be an issue.

The disadvantage of the cold flow technology is that it can start being employed only when the stable operational conditions at the field are established. That is why there is a need for the other hydrate preventing technologies during starts-up and shuts-in. Thus, the complexity of the system against hydrates and its total cost increases.

One of the main challenges of employing the cold flow system in the Arctic is that the technology is new. It has not been employed anywhere and, thus, it does not have a proven track-record. Thus, there are always possibilities for failures that might not have been taken into account under development or have not been revealed under conducting the tests. Implementing new technology in the sensitive and remote environment of the Arctic is very hazardous. Concerning gas and oil production in harsh environment of the Arctic in the future, the industry will try to minimize the amount of offshore operations increasing thereby safety of the personnel. It will be difficult to achieve it with the newly installed technology which potentially may require improvement or elimination of defects on the field.

Despite of all the uncertainties and disadvantages regarding the cold flow technology, it still remains to be an attractive concept preventing hydrates growth not only in the Arctic but in the other different areas of oil and gas production.

Personally, I think that cold flow is a break-through technology in the future of the oil and gas industry. This simple, effective and flexible in production rate technology will cover future demands from the industry. However, it is not ready to be implemented now. More tests, especially large scale tests, are required to eliminate all the uncertainties regarding this innovative technology.

In my opinion, the cold flow technology should be employed first in less sensitive and more familiar for the petroleum industry areas before it reaches the Arctic. It has to be taken into consideration that any operation in the Arctic will naturally demand significantly more planning, more review, more contingency, more spares and more time than an operation in more benign climates closer to major infrastructure.

Recommendation and Limitation

There are several aspects that deserve more attention and should be investigated closer in order to understand even better the cold flow technology and its importance for the future development of multiphase transport. These were not evaluated in this master thesis, but should be considered in further studies.

For the Polarrev field development utilizing cold flow as the method to tackle the hydrates, I would recommend to carry out a flow simulation using HYSYS or a similar software. It will help to understand the flow behavior better.

The combination of DEH and injection of inhibitors is mentioned in the report as one of the techniques to prevent hydrate formation and deposition. Unfortunately, this technique is not analyzed in the Polarrev study case due to lack of time. I would recommend to carry out the analysis and compare the obtained results with the results presented in this thesis.

I would highly recommend to pay more attention at the cooling process described in the SINTEF-BP cold flow concept, namely overall heat transfer coefficient. The value used in the case study is the same as SINTEF used in their research and is equal to 100 W/m^2K. However, this particular value seems to be high according to the industry, where it should usually be in the range of 15-20 W/m^2K. These uncertainties regarding the OHTC have to be resolved.

I would also recommend to conduct a similar analysis like in this master thesis but for various distances from shore/a processing platform. It would be interesting to observe how preferences for different hydrate prevention techniques vary with the distance.

There are some limitations regarding this master thesis to consider. First of all, it is limited resources. The person I was in contact could not share all the information due to a confidentiality agreement. Some technical information, especially different values, as well as the real cost of equipment is difficult to acquire. Thus, they are assumed based on the observations and documental studies.

Different flow assurance systems have different laying cost. It is not taken into account in the evaluation of capital expenditure of these different systems. Although, it could change the final cost picture.

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Appendix

Appendix 1. Heat Exchanger Unit

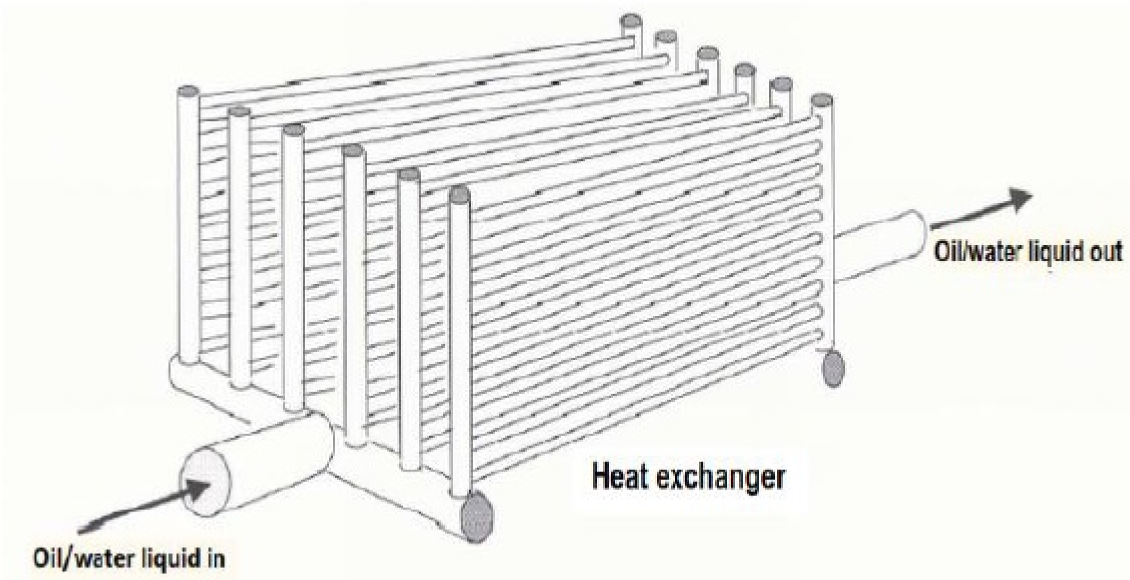

Figure 25. Tube heat exchanger unit of the NTNU concept [13]

Appendix 2. Refrigeration Unit

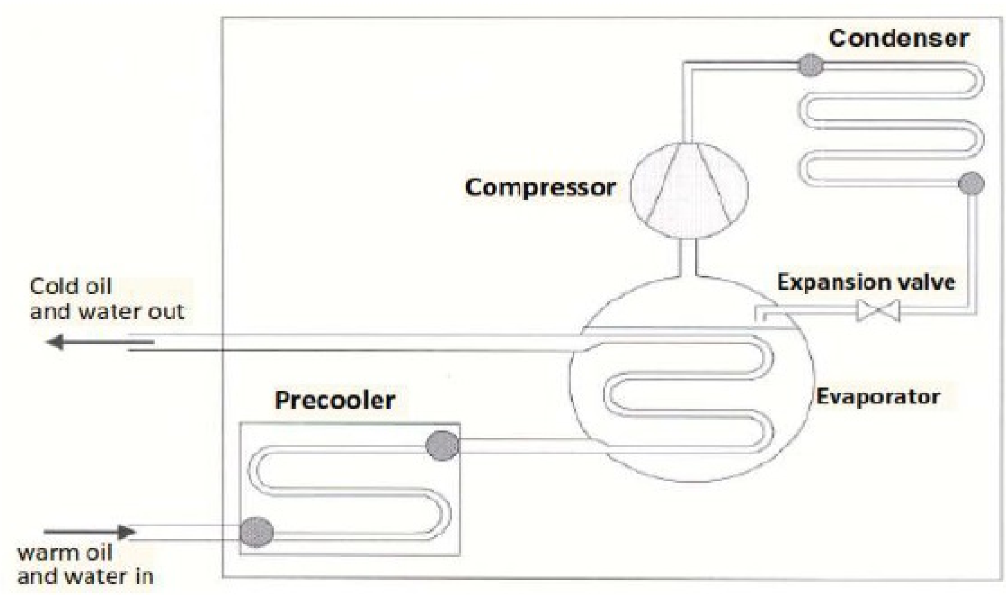

Figure 26. Refrigiration unit of the NTNU concept [13]

Appendix 3. Baillie-Wichert Chart

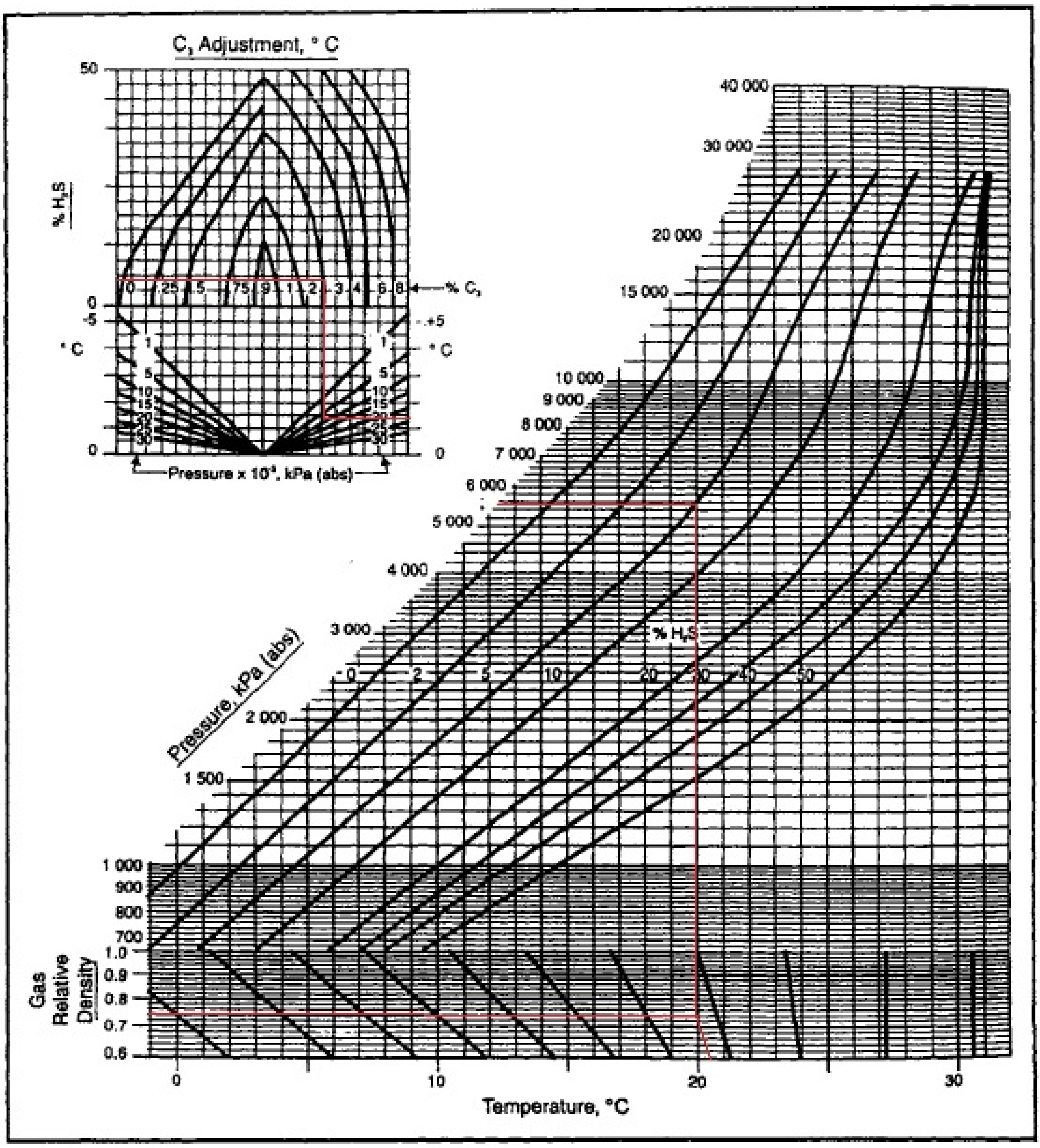

Figure 27. Baillie-Wichert chart for estimating hydrate formation conditions [6]

Appendix 4. Chart Showing the Effect of Thermodynamic Inhibitors

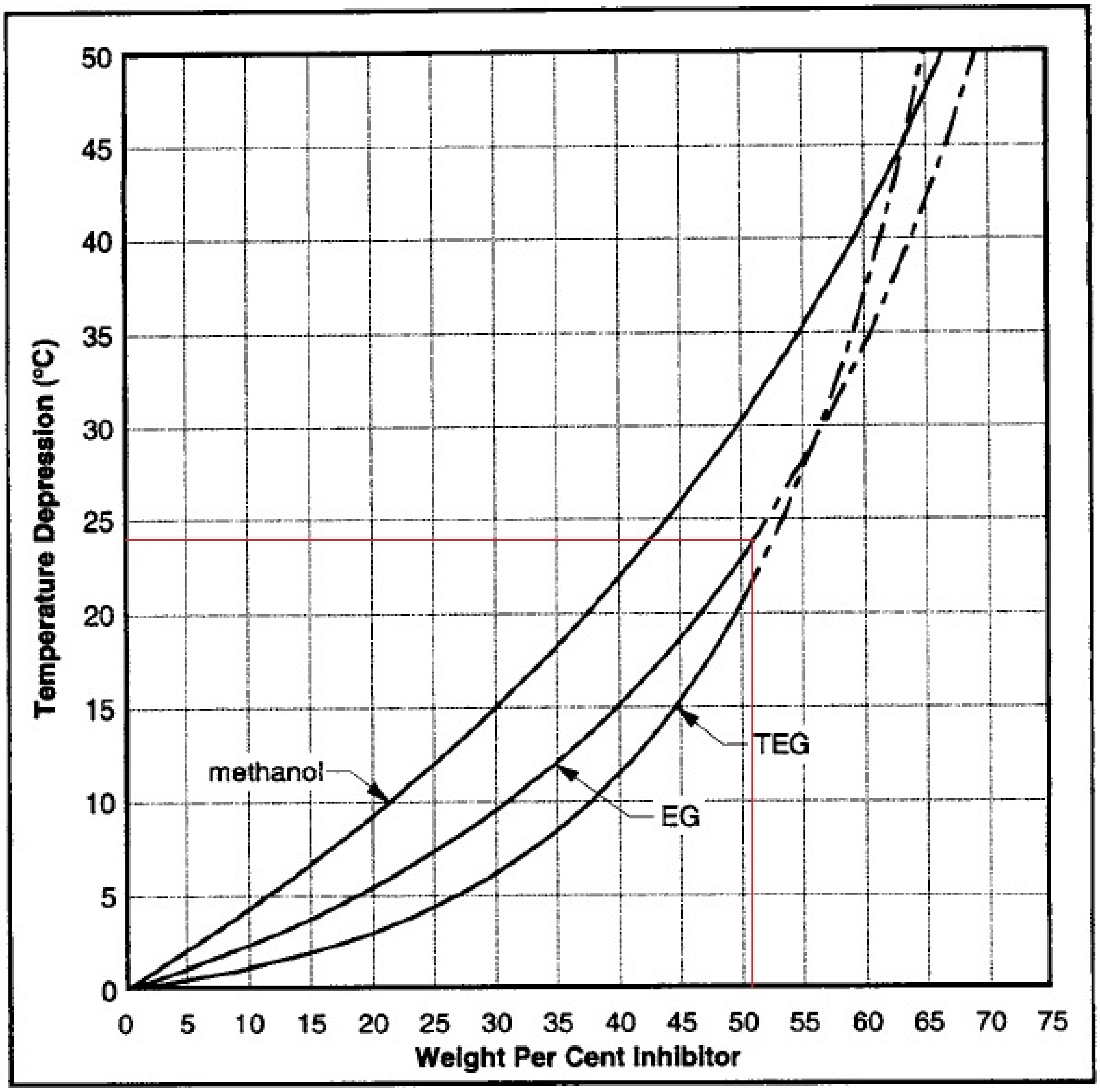

Figure 28. The inhibiting effect of methanol, ethylene glycol (EG), and triethylene glycol (TEG) [6]

Appendix 5. Categories of chemicals classified by the CPA

Table 25. Categories of chemicals classified by the Climate and Pollution Agency [26]

Categories of chemicals	Description
Green	Chemicals which are considered to have little or no environmental effect. These chemicals need no special permission to be discharged into the sea.
Yellow	Chemicals which are in use, but are not covered by any of the other categories. These chemicals can normally be permitted to be discharged into the sea without notice.
Red	Chemicals which are hazardous to the environment and hence should be replaced. Can be released into the sea after government approval, but should be prioritized for substitution.
Black	Chemicals which are not allowed to be discharged, unless special approval is given. They can be discharged in special cases due to safety reasons.

Appendix 6. Heat capacity chart for natural gas

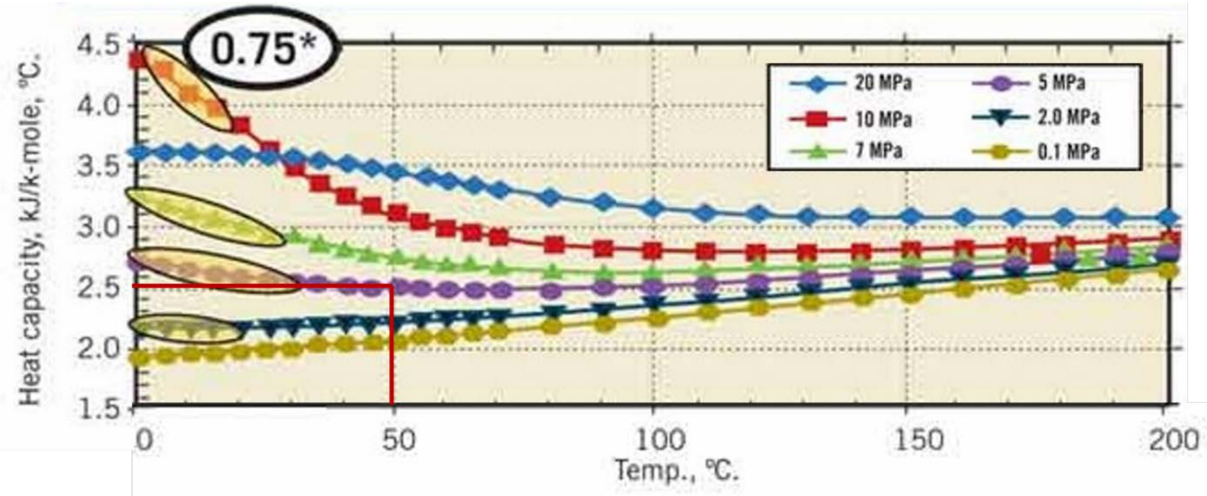

Figure 29. Heat capacity chart for natural gas