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Master Thesis

"GAS HYDRATE RESERVOIRS: DETECTION, SIMULATION AND PRODUCTION TECHNOLOGIES"

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Abstract

Natural gas hydrates are distributed all over the planet, mainly in marine environments and in permafrost regions. If production methods that are developed could be economically profitable, the huge amounts of reserves of natural gas hydrates would be a potential source of energy. In order to develop drilling and production operations in this type of reservoirs, formation and dissociation of hydrates should be investigated. Due to the fact that there are not many production operations conducted in gas hydrate reservoirs, and therefore there is not enough production data available, it is very important to develop numerical simulations in order to predict productions in experimental studies and field production trials. In this thesis, an overview of gas hydrate reservoirs with a focus in reservoirs located in permafrost regions, such as Mallik, Messoyakha and Alaska North Slope, has been made. The Mallik site was drilled in 1998, while the focus was Gas Hydrate Research Well Program applied to Mallik 2002 site, thermal injection and depressurization of in-situ gas hydrate-bearing formation. Three tests were conducted and three zones of hydrate layers were observed. The Messoyakha Gas Field is located in Siberian permafrost, in Russia. It was the first discovered gas hydrate field. This is the only field where long-term production took place in an area of gas hydrate reservoirs. Production of gas reached the maximum in the first years of production until 1982. Evidence for the occurrence of gas hydrates in the Alaska North Slope comes from the analysis of cores and downhole logs from the gas hydrate test wells: The Mount Elbert, and Iġnik Sikumi wells. Mount Elbert Gas hydrate site is located in the Milne Point Field near the Prudhoe Bay oil field. In December 2018, drilling operations finally confirmed the presence of gas hydrates reservoirs. The new method of production was used, injection of CO_2, and it is shown to be technically feasible in combination with depressurization. Nankai Trough, example of offshore gas hydrate production, is presented because of the fact that two production tests were conducted in this site. Method used for production was depressurization, and the goal of this study was to prove that production from offshore gas hydrates can be used for commercial purpose.

Keywords: gas hydrates, Mallik, Messoyakha, Alaska North Slope, Nankai Trough

1.INTRODUCTION

High pressures and low temperatures are the required factors for the formation of gas hydrates, where the gas hydrates are a crystalline solid formed of water and gas. The origin of the gas trapped inside the hydrates could be biogenic or thermogenic. Natural gas hydrates occur in the pore space of sediments; therefore, such formations represent gas hydrate reservoirs. The role that gas hydrate reservoirs may play in contributing to the world's energy requirements will depend ultimately on the availability of producible gas hydrate resources and the cost to extract them.

There are three classes of gas hydrate reservoirs, Class 1 (a combination of free gas zone and hydrate layer), Class 2 (a combination of water layer and hydrate layer) and Class 3 (hydrate layers surrounded by impermeable rocks). (Figure 10)

In order to produce natural gas from gas hydrates, several methods are used, such as depressurization, thermal stimulation, and injection of inhibitors. The depressurization method is characterized as decreasing the pressure of hydrates below the pressure of equilibrium where hydrates are stable, which causes the dissociation of hydrates. Using thermal stimulation, the temperature is increased above the temperature of dissociation. It is possible to apply this method when there is enough energy that is continuously used to overcome the endothermic heat of dissociation. Injection of inhibitors is also used to change equilibrium conditions by injecting the organic or inorganic compounds. Sometimes the injection of inhibitors is used with other methods, such as thermal stimulation or with additional types of inhibitors.

2. HYDRATES

2.1. Properties of Hydrates

Gas hydrates are solid compounds formed of water and gas molecules, under conditions of moderate pressure and low temperature. The gas molecules, or guests, are trapped in water cavities, or the hosts, that are composed of hydrogen-bonded water molecules. (E. Dendy Sloan 2008)

Hydrates can also be defined as inclusion compounds, where molecules of water represent the cage of polygonal geometry surrounding the other type of molecule ,which is usually a molecule of gas. The water molecules are arranged in a rigid framework of cages (called a clathrate), many of which are occupied and stabilized by a molecule of methane. (Charles K. Paull 2001)

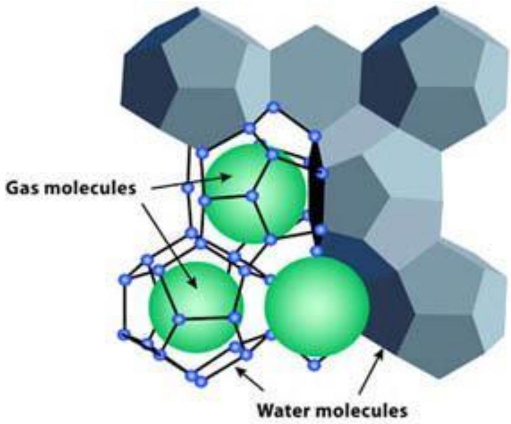

Figure 1 Gas hydrate crystal unit

The bond of the hydrate structure is the hydrogen bond between water molecules, which is a polar bond. The guest molecules are free to rotate inside the cages built up from the host molecules. (Carroll 2009)

Methane is the predominant gas contained in hydrates. With regards to density, in the regions of the low temperatures and pressures, hydrates of methane have a density of 0.9g/cm^3. Hydrates are made up of more than 85% of water molecules, which have properties of ice.

2.2. Structures of hydrates

There are three types of structures of hydrates, primitive cubic structure or structure I, the face-centered cubic structure or structure II, and the hexagonal structure or structure H. These structures are represented as a combination of crystal units. There are five crystal units, denoted as follows 5^{12}, $5^{12}6^{2}$, $5^{12}64$, $5^{12}6^{8}$, $4^{3}5^{6}6^{3}$, according to their related geometry. The general form of crystal units is N^{m}, where N is represented as edge number of face geometry, and m is the number of faces with N edges.

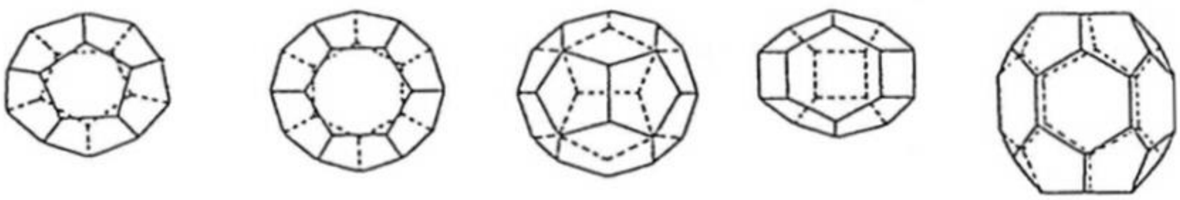

Figure 2 The 5 crystal units of natural gas hydrates (E. Dendy Sloan 2008)

2.2.1. Structure I

The structure I consists of the first and second type of crystal unit (5^{12} and $5^{12}6^{2}$). Geometrically, they are contained by six large and two small cavities per unit cell, which are constructed from 46 H_2O molecules bonded with hydrogen bond. Structure I, a body-centered cubic structure, forms with natural gases containing molecules smaller than propane; consequently sI hydrates are found *in situ* in deep oceans with biogenic gases containing mostly methane, carbon dioxide and hydrogen sulphide. (HENRIET 1998) The formula for the ideal unit cell is shown below:

$$6X.2Y.46H_2O$$

Equation 1

Where X represents the guest, molecules filled in large cavities, and Y represents the guest molecules filled in small cavities, six represents the number of large cavities and two is the number of small cavities.

Table 1 Geometry of cages, Structure I (E. Dendy Sloan 2008)

Structure	**I**	
Crystal system	Cubic	
Cavity/crystal unit	Small	Large
Description	5^{12}	$5^{12}6^{2}$
Number of cavities	2	6

Methane, ethane, carbon dioxide, or hydrogen sulfide typically form the Structure I hydrate. The Structure I hydrate is shown in Figure 3:

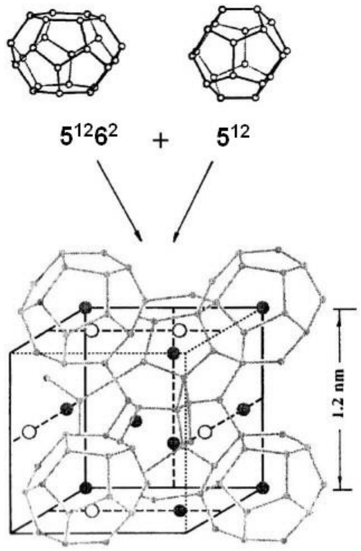

Figure 3 Structure I (E. Dendy Sloan 2008)

2.2.2. Structure II

Structure II consists of the first and third type of crystal unit (5^{12} and $5^{12}6^{4}$). Geometrically they are made up of eight large and sixteen small cavities per unit cell, which are constructed from 136 H2O molecules bonded with a hydrogen bond. Structure II, a diamond lattice within a cubic framework, forms when natural gases or oils contain molecules larger than ethane but smaller than pentane; sII represents hydrates from thermogenic gases. (HENRIET 1998)

The formula for the ideal unit cell is shown below:

$$8X.16Y.136H_2O$$

Equation 2

Table 2 Geometry of cages, Structure II (E. Dendy Sloan 2008)

Structure	**II**	
Crystal system	Cubic	
Cavity/crystal unit	Small	Large
Description	512	51262
Number of cavities	16	8

Structure II is shown Figure 4 - this structure will be formed in the presence of small amounts of heavier gases like propane or iso-butane:

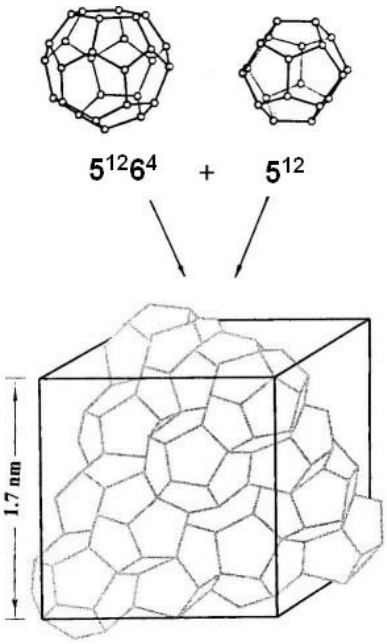

Figure 4 Structure II (E. Dendy Sloan 2008)

2.2.3. Structure H

Structure H is also known as a "Double Hydrate" because in order to be stable, there need to be two guest species. Structure H consist of 34 H_2O molecules and six gas molecules, constructed with a combination of three 5^{12}, two $4^35^66^3$, and one $5^{12}6^8$ crystal units in a unit cube. Formation of Structure H hydrate requires a small occupant (like methane, nitrogen or carbon dioxide) for the 5^{12} and $4^35^66^3$ cages, but the molecules in the $5^{12}6^8$ cages should be larger than 0.7 nm but smaller than 0.9 nm (e.g. methyl-cyclohexane). (HENRIET 1998) The formula for the ideal unit cell is shown below:

$$2X.3Y.1Z.34H_2O$$

Equation3

Table 3 Geometry of cages, Structure H (E. Dendy Sloan 2008)

Structure		H	
Crystal system		Hexagonal	
Cavity/crystal unit	Small	Medium	Large
Description	5^{12}	$4^35^66^3$	$5^{12}6^8$
Number of cavities	3	2	1

Structure H is shown in Figure 5:

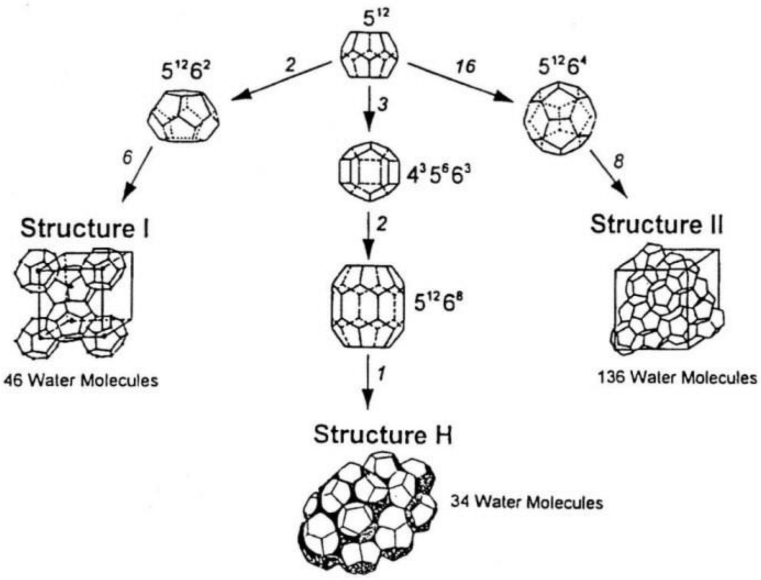

Figure 5 The three hydrate structures and associated crystal units (E. Dendy Sloan 2008)

2.3. Heat Capacity and heat of Dissociation

Consider a closed system of constant volume which is filled with a pure material. The rate of change of specific entropy of the system with respect to temperature may be expressed as (Roger M. Rueff 1988):

$$\left(\frac{\partial Ssys}{\partial T}\right)_V = Vsys\left(\frac{\partial^2 p}{\partial T^2}\right)_V - \left(\frac{\partial^2 \mu}{\partial T^2}\right)_V$$

Equation 4

Where the V specifies that the derivatives are taken with respect to constant total system volume.

a) Heat capacity

The heat capacity at the constant volume is defined as:

$$Cv, sys \ = VsysT\left(\frac{\partial^2 p}{\partial T^2}\right)_V - T\left(\frac{\partial^2 \mu}{\partial T^2}\right)_V$$

Equation 5

The molar heat capacity is defined as the amount of energy in the form of heat that need to be added to one mole of gas in order to cause an increase in temperature by one Kelvin.

b) Heat of Dissociation

Gas hydrate dissociates while absorbing heat; consequently, the temperature of the interval decreases to that of the hydrate stability boundary at that depth. (Nagakubo 2016)

To a fair engineering approximation *H*d is (E. Dendy Sloan 2008):

- a function not only of the hydrogen bonds in the crystal but also of cavity occupation and
- independent of guest components and mixtures of similar size components within a limited size range.

While the Clapeyron equation often provides satisfactory estimates of the heat of dissociation, no information about the hydrate heat capacity is directly determined by that equation. (E. Dendy Sloan 2008)

$$\frac{dP}{dT} = \frac{\Delta H}{T\Delta V}$$

Equation 6

Where ΔH and ΔT represent the enthalpy and volume, respectively, accompanying the process of conversion of liquid water and liquid hydrocarbon into hydrate. The value of ΔH was found to be almost constant at 65.4 ± 2.1 kJ/mol for many gas mixtures. However, the Clapeyron equation is thermodynamically correct, as long as the system is univariant (simple hydrates).

3. RESERVOIRS OF GAS HYDRATES

3.1. Gas hydrate distribution

A huge amount of gas hydrates exists in the world. Scientists in the petroleum sector consider them as one of the biggest sources of natural gas in the future. However, there is still no established technology to extract the gas from gas hydrates. It is clear that gas hydrates are created along most of the continental shelf and slope areas, as well as in many permafrost zones. Some estimates put the amount of natural gas locked up worldwide in hydrate formations as equal to the amount of natural gas available in all other known natural gas resources. In Figure 6 site location of gas hydrate reservoirs is shown, location of recovered has hydrate samples are marked with yellow, while location of inferred occurrence of gas hydrates are marked with red.

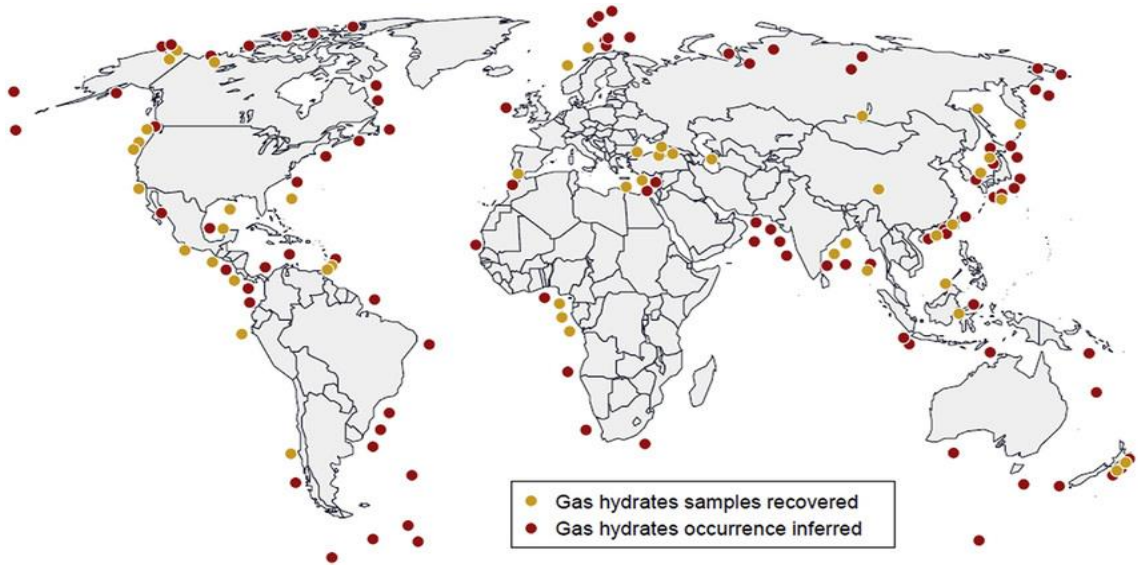

Figure 6 Reserves of hydrates in the world (Ş. Merey, Drilling of Gas Hydrate Reservoirs 2016)

Estimating the initial-gas-in-place in gas hydrates reservoirs, and it was done by estimating gas hydrate stability zone thicknesses, using sea depth, thermal gradients, pressure gradient, and salinity. The temperature gradient and the pressure gradient are physical quantities that describes in which direction and at what rate the temperature and the pressure change the most rapidly around a particular location, with dimensional quantity expressed in units of degrees (on a particular temperature scale) per unit length and for the pressure with dimensional quantity expressed in units of pascals per meter (Pa/m).[1]

[1] https://www.netl.doe.gov/

For example, Johnson (2011) estimated gas in place in gas hydrates deposited in coarse sands.

Table 4 Gas in Place in Hydrate-Bearing Sands (Johnson 2011)

Gas in Place Median (tcm)	Gas in Place Range (tcm)	Region (United Nations Designation)
199	43-437	*USA*
63	15-254	*Canada*
40	1-421	*Western Europe*
0	0-3	*Central and Eastern Europe*
108	43-290	*The former Soviet Union*
6	0-52	*North Africa*
52	1-728	*Eastern Africa*
90	2-747	*Western and Central Africa*
89	3-747	*Southern Africa*
16	1-109	*Middle East*
5	0-51	*China*
11	0-77	*Other East Asia*
26	1-178	*India*
16	1-99	*Other South Asia*
6	2-13	*Japan*
23	1-191	*Oceania*
47	2-735	*Other Pacific Asia*
140	7-901	*Latin America and the Caribbean*
102	4-1280	*Southern Ocean*
187	5-1572	*Arctic Ocean*
1226	**133-8891**	***Total***

Table 4 lists a range of gas hydrate resources between 133 tcm and 8891 tcm. It can be concluded that even with the most conservative estimates of the total quantity of gas in gas hydrates are much larger than the conventional gas resources (404 tcm) and shale gas (204 tcm–456 tcm). (Chong 2015)

Usually, experimental data and modeling results are compared with actual production data to detect and to examine the differences, while in this type of reservoirs actual production data are not available from many fields and that represents one of the difficulties in this moment, since there is no many examples of gas hydrate reservoirs where production is conducted.

Figure 7 Methane gas hydrates samples (Demirbas 2010)

Hydrates have been found in inland seas (e.g., the Black Sea and the Caspian Sea), and in freshwater lakes (Lake Baikal). (Giavarini 2011) In the near past, in studies conducted in 2006, reserves of gas hydrates in India are estimated as the second-largest reserves of gas hydrates, while the largest reserves are in the United States of America. These estimates were conducted by the US Geological Survey. It has been found that the reserves are 100-130 trillion cubic feet in the Krishna-Godavari (KG), Cauvery and Kerala basins. However, even the most conservative estimates place the amount of gas contained within hydrate deposits at least two times as much as the global estimates of conventional natural gas of 4.4 x 10^{14} standard cubic meters. (Koh 2012) Southwestern Japan and western Canada are examples of environments with hydrates occurring at the seafloor, mostly in thrust belts and active margin folds. Although hydrates cannot be found in the basins of the ocean on the deep-sea floor, it can be usually created below continental slopes. This is a consequence of the upward movement of fluid in the areas of higher methane concentration. Countries such as China, Japan, Korea, India, and the USA are now conducting exploration in gas hydrate reservoirs.

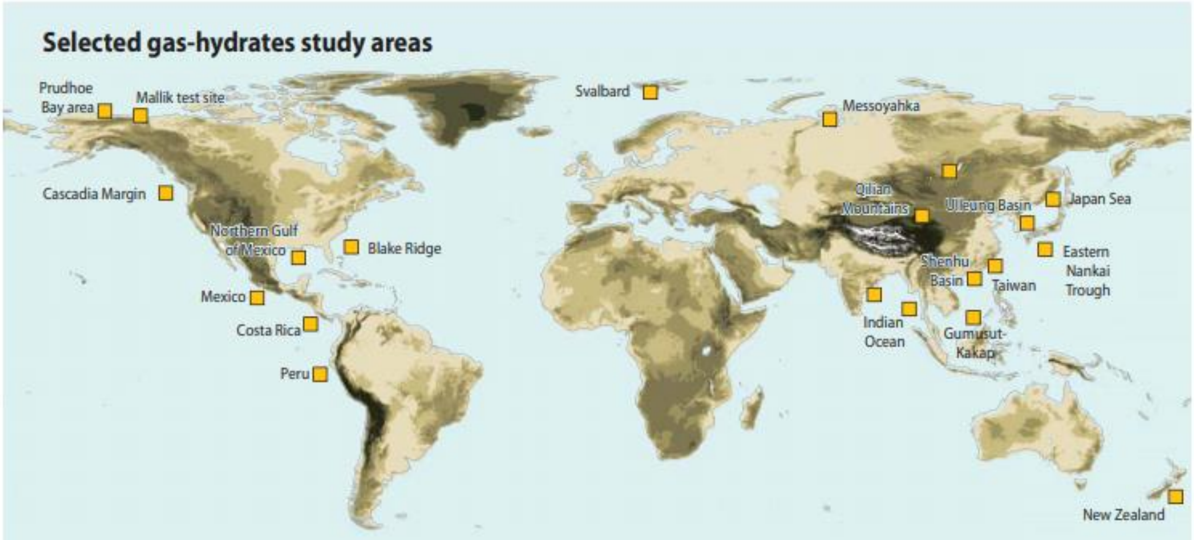

Figure 8 Reserves of hydrates in the world (Beaudoin 2014)

In Figure 8 selected gas hydrates study areas are shown. These areas are listed below:

1. Prudhoe Bay – Located in the North of Alaska. In December 2018 drilling operations confirmed existence of two gas hydrate reservoirs.
2. Malik site – Located in Mackenzie Delta, in Canada, which represents gas hydrate production in permafrost region.
3. Cascadia margin – natural hydrate reservoir located in Barkley canyon. It has been the focus of many marine geological and geophysical studies over the past two decades.
4. Northern Gulf of Mexico – This area is a focus area since 1980s for the study about gas hydrates. Hydrates were found near the seafloor along with hydrocarbon seeps. Drilling program conducted in 2005 confirmed existence of gas hydrates below the Gulf of Mexico.
5. Costa Rica – In this area shallow gas hydrate accumulation in mud volcanoes is proven by a find in surface sediments, located on continental slope of Costa Rica at 1000m depth.
6. Peru – Gas hydrates are identified in the Tumbes Basin, which is located in the north of Peruvian margin. This area was identified by seismic methods.
7. Blake Ridge – Located at the continental margin off southeastern North America. Ocean Drilling Program (ODP) estimated an amount of gas hydrates in marine sediments using the acoustic logs.

8. Svalbard – Archipelago located between northern Norway and the North Pole. According to pressure and temperature, this area is related to permafrost extent. In a 30-year period, from the 1960's to 1990's several deep exploratory wells for oil and gas on Svalbard were drilled.
9. Messoyakha – Example of gas hydrate reservoirs in permafrost region. It is located in Siberian permafrost, Russia. This is the only field where long-term production takes place in an area of gas hydrate reservoirs.
10. Qilian Mountains permafrost is located in the north of Qinghai-Tibet plateau. The Scientific Drilling Project of Gas Hydrates was conducted by China Geological Survey in 2008–2009. Samples of gas hydrates were collected from four different wells.
11. Uleung basin is located in the East Sea. Gas Hydrate Drilling Expedition, as a part of Korean National Gas Hydrate Program, was performed in September 2010. Gas hydrates were recovered and it is concluded that this methane is primarily of biogenic origin.
12. The Sea of Japan – Two types of methane hydrates are confirmed to exist in areas surrounding Japan: "(pore-filling) sand-layer type" existing between the sand particles of sandy sediments under the seabed, and "shallow-type" existing in shape of the block called gas chimney structure at the surface of the seabed to under 100 meters.[2] In March 2013 offshore production tests were conducted in this area
13. Eastern Nankai Trough is located beneath the Pacific Ocean off the southeast coast of Japan. The first attempt of production project in this area was developed in 2013, after which the second one was conducted in 2017, using two wells and applying depressurization.
14. Shenhu Basin – located in Northern South China Sea. High concentration of gas hydrates was recovered from silty clay sediments. In order to detect the gas hydrate occurrences and determine the nature and distribution of gas hydrates, a gas hydrate drilling expedition GMGS-1 was initiated by Guangzhou Marine Geological Survey using M/V Bavenit along with specialized Fugro and Geotek in Shenhu area in 2007.[3]
15. Taiwan – Gas hydrates in this region are located in Southwestern Taiwan. Bottom simulating reflector was the key indicator of the presence of gas hydrates beneath the seafloor.

[2] https://www.japex.co.jp/english/business/innovate/methanehydrate.html
[3] https://www.hindawi.com/journals/jgr/2011/370298/

16. Indian Ocean – Accumulations of gas hydrates in this area are located in the Bay of Bengal. The scientists conducted ocean drilling, conventional sediment coring, pressure coring, downhole logging and analytical activities to assess the geologic occurrence, regional context, and characteristics of gas hydrate deposits in the offshore of India.[4]

3.3. Origin of Gas in Hydrate Reservoirs

Gas from the gas hydrates has two types of origins; one is biogenic and the other is thermogenic. The temperature and pressure conditions for hydrate stability depend on the composition of the gas and on the presence of salts and other components in seawater. It is generally believed that pore water has to be fully saturated with methane before natural hydrate can form. (Demirbas 2010)

a) Biogenic Origin

The source of methane in naturally occurring hydrates is largely from biogenic origin, where methane is generated in situ by methanogenesis as bacteria break down organic matter. (Carlo Giavarini, Gas Hydrates: Immense Energy Potential and Environmental Challenges 2011) Biogenic methane is also called microbial. In the microbial process, organic debris is decomposed into methane by bacteria in an anoxic environment. (Demirbas 2010) Biogenic methane formation may take place both *in situ* and beneath the hydrate stability zone. Although gas hydrates containing biogenic gas origin are composed primarily of methane in a sI structure, other products of microbial activity, such as carbon dioxide and hydrogen sulfide, may be present. (Roggers 2015)

b) Thermogenic Origin

Gas hydrates created from thermogenic natural gases are defined as thermogenic hydrates. Thermogenic, massive hydrates are associated with faults in fine-grained sediments rather than biogenic, dispersed hydrates in course-grained rocks. (Westbrook 1994)

[4] https://www.usgs.gov/news/large-deposits-potentially-producible-gas-hydrate-found-indian-ocean

In the thermogenic process, thermal cracking of organically derived materials forms petroleum hydrocarbons (including methane). This generally occurs at considerable depth (more than 2 km) in sedimentary basins where temperatures exceed 273 K. (Demirbas 2010) Cracking represents the process where conversion of kerogens into hydrocarbon happens. Thermogenic gas is made up of ethane and heavier hydrocarbons. Thermogenic methane must be formed below the hydrate stability zone, and then to move up.

3.4. Formation of gas hydrate and significant parameters

Clathrates occur wherever the conditions within the sediments are in the methane clathrate stability field, and where methane and water are available. This stability is limited by temperature and pressure: gas hydrates are stable at low temperatures and/or high pressures. (Demirbas 2010) The formation of gas hydrates is defined as a process of crystallization along with nucleation, agglomeration, growth, and cracking. Cracking is process whereby complex organic molecules such as kerogens or long-chain hydrocarbons are broken down into simpler molecules. Agglomeration represents the process where the sticking of particles to one another or to solid surfaces. Nucleation starts in the gas-water interface, due to the fact that gas is dissolved in water and there is the highest concentration of gas on the interface. Cooling is required to remove the hydrate heat of formation. Mass transport is required to dissolve the natural gas in water and to bring the dissolved gas molecules into contact with a growing hydrate crystal. At greater depth the temperature increases and becomes too high to keep the formation of hydrates stable. As a result, the depth of the lower boundary can be determined by the geothermal gradient. The possibility for creating gas hydrates in deeper sediments is very low because in deeper parts, temperature is high due to geothermal gradient so very high-pressure values are essential for hydrate formation. (Max, Exploration and Production of Oceanic Natural Gas Hydrate 2016)

The melting temperature of gas hydrates is affected by pressure. If the pressure is too low or the temperature too high, the hydrates dissociate (break down), the methane is released and the gas can seep from the seafloor into the ocean. (Kiel 2018) Methane gas hydrates can be stable in different environment, usually they are present at the seafloor if temperature and pressure are suitable, or beneath the surface in the areas of very low temperatures such as arctic. In the case of continental slopes, stability zone of hydrates is a few hundred meters under the seafloor, while in permafrost areas it can reach 1000 meters beneath the surface.

Beneath the continental shelves at temperature latitude, it is not possible to observe the stable formation of hydrates. In addition, there is not enough organic carbon to yield significant concentrations of methane in the local sediments. Figure 9 is an example of a marine and permafrost environment. In marine environments the temperature is decreasing as we are going from the sea surface to seafloor, after reaching the sediments it starts to increase. Marine hydrates are stable if the sea depth is greater than 300 to 400 meters. (Demirbas 2010)

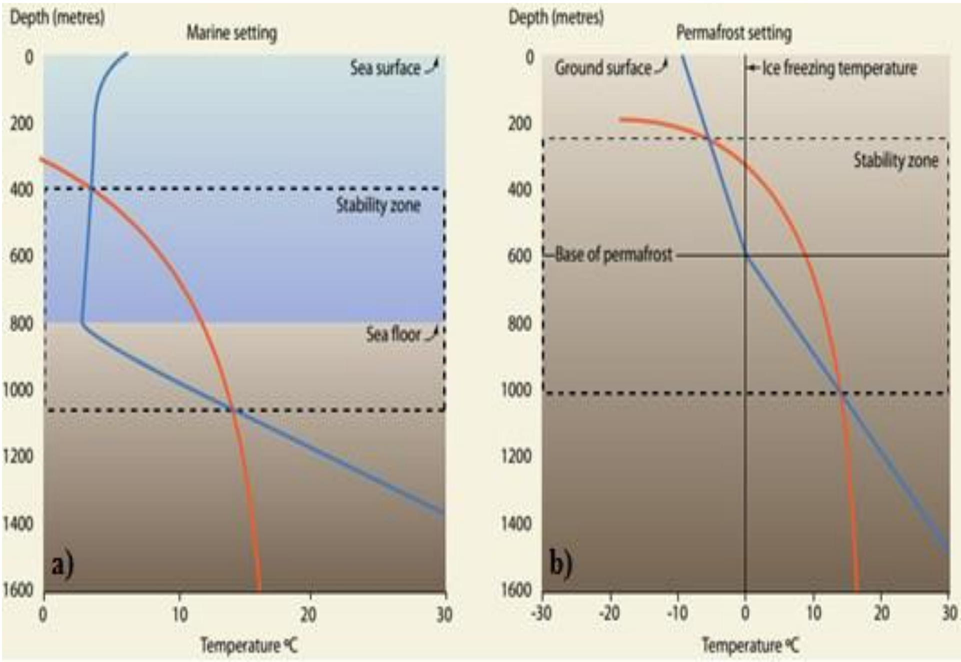

Figure 9 Stability conditions for gas hydrates (Beaudoin 2014)

The blue curve represents the thermal gradient, while the red curve represents the hydrate equilibrium curve. From the first intersection of blue and red curve to the second one, gas hydrate stability zone is present. In the marine environments first part is water so the presence of hydrates is only in sediments. At the point of intersection stability zone is not present anymore, so below this depth free gas is trapped in porous media. For example, in ocean sediments, CH_4 hydrates can be found between 500 m and 3000 m depending on hydrate formation conditions. However, the possibility of CH_4 hydrate in deeper sediments is very low because in deeper parts, temperature is high due to geothermal gradient so very high-pressure values are essential for hydrate formation. (Max, Exploration and Production of Oceanic Natural Gas Hydrate 2016)

3.5. Classification of Gas Hydrate Deposits

Natural gas hydrates accumulations are divided into three main classes. (G. &. Moridis 2003) These types of classes are created according to the initial conditions of the reservoir and geological features. Additionally, there is Class 4.

- Class 1 – Combination of free gas zone and hydrate layer, where free zone is under the stable hydrate layer,
- Class 2 – Combination of water zone and hydrate layer, where water layer is under the stable hydrate zone,
- Class 3 – Layer of stable hydrate zone with low permeable rocks such as clays or shales, above and under hydrate zone,
- Class 4 – Without geological strata around.

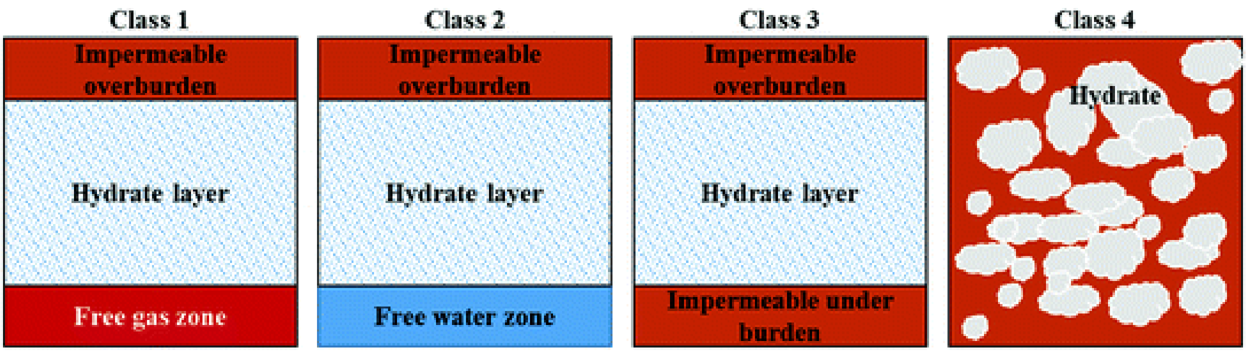

Figure 10 Classes of hydrate reservoirs (Sangwai 2017)

Class 4 gas hydrates are distributed only in sea floor, and its saturation is very low, therefore they are not considered as a target for production. Class 4 hydrate is the most common hydrate in nature and then Class 1 hydrates are second most common hydrate reservoir. (Worthington 2010)

4.DRILLING GAS HYDRATE RESERVOIRS

4.1. Well location selection

The probable positioning of wells for drilling gas hydrate reservoirs is determined according to the results of studies conducted during exploration. In order to understand and to describe the hydrate stability zone and parameters such as the thickness of the given zone, the environment must be known, because pressure and temperature profiles vary in different types of reservoirs, as these reservoirs could be located in marine or arctic environments.

In order to determine the location of exploration wells in gas hydrate reservoirs, certain standards must be followed or certain criteria must be matched:

- Stability zone of gas hydrates, zone where hydrate reservoirs are likely to exist at appropriate pressure and temperature,
- Organic rich sediments – in order to be considered as a source of energy gas hydrates should be located in sediments,
- BSRs (Bottom Simulating Reflectance) – the anomaly that is located between the gas hydrate stability zone and the free gas zone, because of phase difference,
- High saturation of gas hydrates (Average gas hydrate saturation of the typical pore-filling reservoir is 61.9%, and in fracture filling reservoirs it is 69.4% according to Xiao et al., 2017). (WEI Wei1 2017)

4.2. Drilling in gas hydrate reservoirs

Drilling gas hydrate reservoirs is not yet explored very well because there is not much production from these types of unconventional reservoirs. There are many complications that can occur during drilling gas hydrate reservoirs. Gas hydrate can be formed inside the well and in that way to cause plugging. Unexpected hydrate dissociation could happen and cause a blowout or slope failure. Wellbore stability can be affected after hydrate dissociation. Logging while drilling is crucial for selecting drilling tests and the locations of exploration wells. Instead of using the time-consuming coring operation that also has the risk of dissociating the gas hydrate at the rig floor, it is much faster to examine the area of the gas hydrate with the logging while drilling method (LWD).

It is important to separate tests conducted for production and exploration wells when conducting well tests in gas hydrates. The stability of production wells is one of the most important factors that should be considered while drilling. Stability is important because these wells are used for long production tests. In addition, the drilling fluid used in production wells needs to be specifically designed. In offshore drilling, most shallow gas hydrate exploration wells are drilled without riser. (Ş. Merey, Drilling of Gas Hydrate Reservoirs 2016) Riser is large-diameter pipe that connects the subsea BOP stack to a floating surface rig to take mud returns to the surface. Without the riser, the mud would simply spill out of the top of the stack onto the seafloor.

In Figure 11 Resistivity, Porosity and Hydrate Saturation are displayed. As we can see from this figure the resistivity logs indicate where the high peaks can be observed – the gas hydrates exist. Values of hydrate saturation are reaching the highest values where resistivity log values are also high. In addition to log data, drilling data such as the drilling rate can be used to determine the gas hydrate zone. Generally, in gas hydrate sections the relative drilling rate decreases, due to the solid nature of the gas hydrate. (T. Collett 1992)

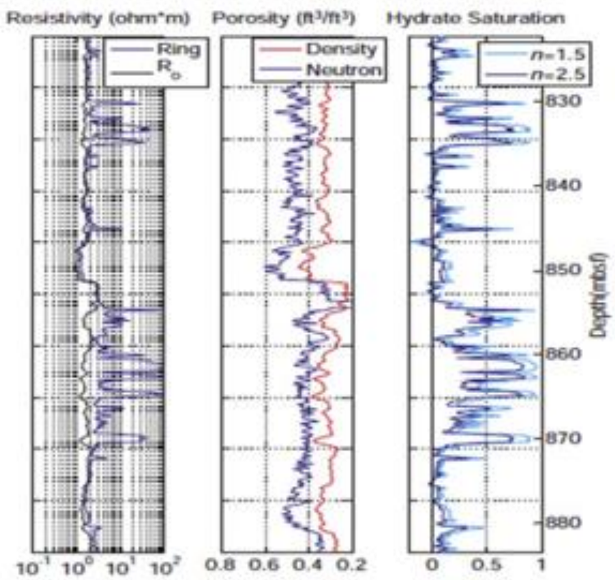

Figure 11 Hydrate saturations, resistivity and porosity logs (Cook 2009)

From Table 5 the behavior of well logs describing gas hydrate zones can be observed, where LWD was used to determine these zones.

Table 5 Well logs in gas and gas hydrate zones (Ş. Merey, Drilling of Gas Hydrate Reservoirs 2016)

	Gas zone	**Gas hydrate zone**
Resistivity	Increase	Increase
NMR porosity	Decrease	Decrease
Acoustic velocity	Decrease	Increase
Neutron porosity	Decrease	Increase
Density porosity	Increase	Increase

4.3. Casing cementing in gas hydrate wells

The type of wells used during the exploration of hydrates is mostly open-hole without introducing casing. This is because the purpose of these wells is to obtain core and log data of sediments where gas hydrates are present.

Since conventional types of well cement have a high heat of hydration, a specially designed cement slurry is necessary to avoid gas hydrate dissociation after casing cementing in gas hydrate wells. Therefore, these specially designed cements for gas hydrates should have the following (Ş. Merey, Drilling of Gas Hydrate Reservoirs 2016):

- Lower heat of hydration than conventional cements,
- Lower thermal conductivity than conventional cements,
- Superior anti-gas migration performance than conventional cements,
- Low density for oceanic hydrate deposits as well as high compressive strength.

5.GAS PRODUCTION FROM HYDRATE RESERVOIRS

In order for hydrates to be created, temperature should be low while the pressure should be high. Point C represents the three-phase critical point, where all three phases are in equilibrium. Q2 represent the point where hydrocarbon gases and liquid, water and solid hydrates are in equilibrium. Q1 is the freezing point where ice, hydrate, water and hydrocarbon gases are in equilibrium. The line between Q1 and Q2 represents a hydrate formation curve.

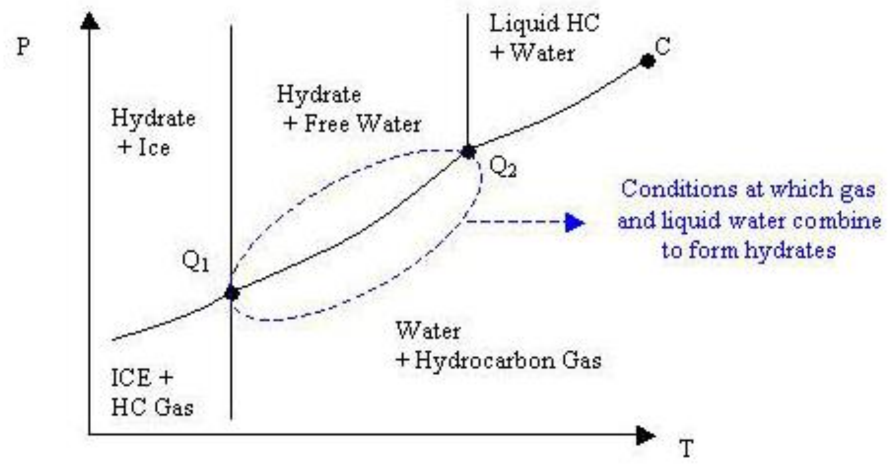

Figure 12 Phase Diagram for a Water/Hydrocarbon (HC) System

Prediction of the hydrate formation curve was investigated by (Katz, 1945) and (Carson and Katz, 1942). Dissociation is conducted to turn hydrates from a solid state into water; which will make possible to produce gas from hydrates conventionally through the network of regular wells. Methods of dissociation of gas hydrates are based on shifting conditions of the reservoir bellow the equilibrium state.

It must be noted that as an endothermic process, it is necessary to add some thermal energy to the system in order to be able for dissociation to happened. One way in which energy could be added to the system: is from the surroundings and from the formation. The other is to use some artificial methods such as heat stimulation. The energy required to dissolve hydrates in the reservoir is approximately 10% of what the produced methane can give off (when heat losses are disregarded).

The surface where the hydrates initially can be found is called the decomposition front, due to the fact that decomposition does not occur in the entire reservoir, and depends on a variety of reservoir conditions.

The dissociation of hydrates is an endothermic process and the hydrates get colder as they are decomposed. In Figure 13 it is shown how different production schemes affect the equilibrium point. After thermal stimulation the conditions will be shifted to the right, of the hydrate dissociation curve may be shifted towards lower temperatures by adding a hydrate inhibitor, while after depressurization conditions will be shifted towards lower pressure.

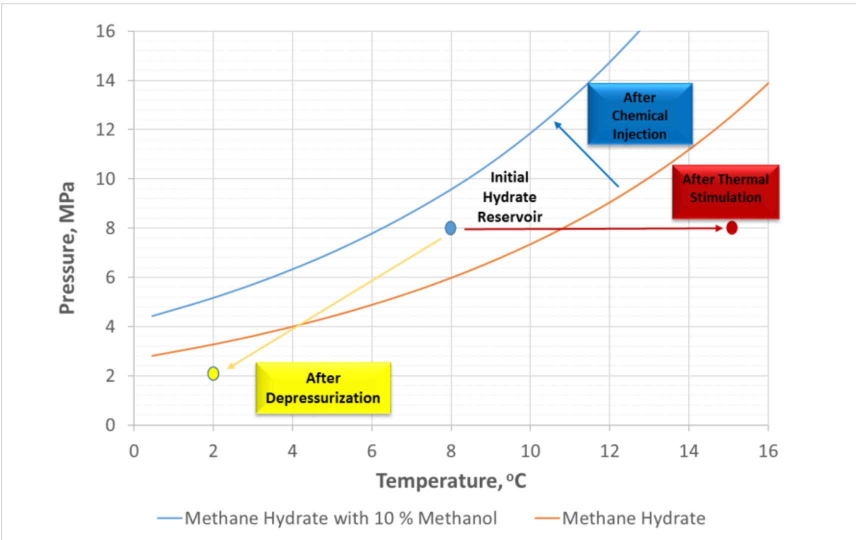

Figure 13 . Production scheme effects on equilibrium (S. Merey 2016)

5.1. Production Schemes

There are four important production schemes for reservoirs of gas hydrates:

- Thermal stimulation,
- Depressurization,
- Inhibitor injection,
- CO_2 injection.

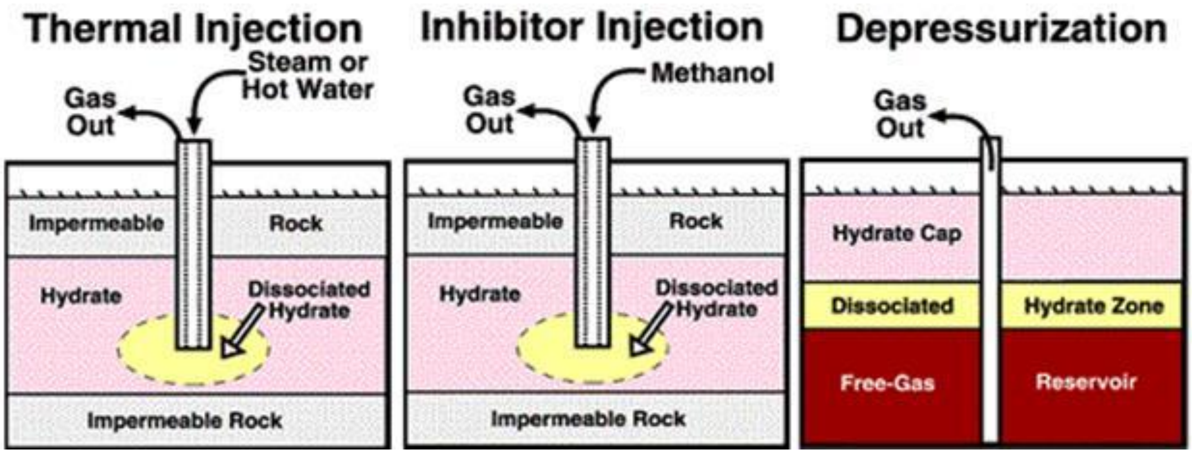

Figure 14 Production schemes (Thermal injection, Inhibitor injection and Depressurization) (T. J. Collett 2009)

In Figure 14 thermal injection, inhibitor injection and depressurization are shown.

5.2. Thermal Stimulation

The thermal stimulation scheme includes:

- Steam injection,
- Hot liquid injection,
- Fire sweeping,
- Direct heating (using microwaves etc.).

Thermal stimulation has its advantages and disadvantages. The main advantage is the fact that the process of dissociation is fast and effective while the disadvantage is the cost of introducing the heat into a reservoir. Introducing heat into the reservoir faces challenges such as losing most of the heat in sediments and through the equipment. These factors are extremely important for calculating the price and energy efficiency ratio.

There are numerical and experimental studies that are conducted in order to recognize the relationship between hydrate dissociation and thermal stimulation. Feng has attempted to combine production methods for producing gas from gas hydrates. Thermal stimulation and depressurization were used simultaneously to produce a considerable amount of gas from hydrate reservoirs. Gas was produced with dual wells while injecting hot water during depressurization. (Feng 2015) Wang suggested that a high hot water injection rate decreases energy efficiency. (Wang 2013) Comparable conclusions were also made in the study conducted by Zhao. (J. C. Zhao 2012) Kawamura conducted a study on producing gas from hydrates using steam injection, and according to this study, 44% of total gas was produced, this study was conducted in a lab on the hydrate formed inside the core with a 5 cm diameter and a 50 cm length. (Kawamura 2007)

5.3. Depressurization

In the process of producing free water or gas the pressure in the hydrate is reduced below the equilibrium pressure. When the pressure starts decreasing it causing the hydrate to decomposes until the vapor pressure is accomplished again, the temperature is now lower than before the pressure started decreasing. The main issue with this method is the fact that the process is very slow. It is more cost-effective since with depressurization there is no need to introduce heat into the reservoir. Although there is no additional heat input, disadvantages of the depressurization method are low gas production rates, high amounts of water production, the risk of hydrate reformation due to fast cooling, and the risk of geomechanical failures (Y. M. Konno 2010). With the decrease of the pressure, the gas production rate and cumulative gas production increases. (X. S. Li 2011) According to Yang et al., under rapid depressurization, the hydrate dissociation is slower and gas production is decreased. A

lthough some studies said that increasing production is affected by the heat coming from ice, the self-preservation can cause plugging to the pores. The self-preservation of gas hydrates is defined as a very slow decomposition of gas hydrates when the external pressure drops below the three-phase equilibrium pressure of the gas hydrate system at sub-zero temperature (below -3 or -2°C), and as a result, a thin film of ice emerges on the surface of the gas hydrate. (Chuvilin 2011)

According to the numerical study done by Huang et al 2016, it is not possible for depressurization to occur when the permeability of the reservoir has a value higher than 2 Darcy and the saturation of the gas hydrate is above 70%. The gas produced from gas hydrates can be divided into stages.

The first stage produces free gas and water (if any), resulting in the reduction of pressure, and dissociation of hydrates begin. It is not possible to produce water or gas if the permeability is low than 10 mD if depressurization method is going to take place. The depressurization method also causes a high amount of water production because water is released after hydrate dissociation. It is usually expected that the water produced from gas hydrate reservoirs is freshwater and may be released into the marine environment. (Max, Exploration and Production of Oceanic Natural Gas Hydrate 2016)

5.4. Inhibitor Injection

When injecting inhibitors, the pressure and temperature equilibrium shift. The most common inhibitor used is methanol, but ethylene, ethylene glycols, calcium chloride, and salt are also used. The goal of inhibitor injection in gas hydrate reservoirs is to shift the hydrate equilibrium line upward. Using only thermal stimulation does not yield very good results. The location of the reservoir could be an issue due to the fact that large amounts of energy could be lost in the rocks surrounding. Even so, thermal stimulation is less efficient in comparison to other methods. In addition, compared to other production methods such as depressurization and thermal inhibition, this method is not much preferred by scientists because it is very expensive and environmentally stressful. (G. C. Moridis 2013) The main use of inhibitors is to avoid the formation of gas hydrates in pipelines while transporting the gas.

5.5. CO_2 Injection

Injection of CO_2, or a mixture of CO_2 and N_2 can be considered as new technique used for production from gas hydrate reservoirs. This replacement is called CO_2-CH_4 swapping or replacement. (Kazunari Ohgaki 1996) This method can be used for production of methane and for sequestration of CO2, while geomechanical stability is not disturbed. This is proved in study conducted by Hyodo (M. L. Hyodo 2014) where he conducted experiments before and after swapping the molecules CO_2 and CH_4, and results were indicating that reservoir remained stable after forming a new CH_4-CO_2 hydrate layer. In the study conducted by Liu *et al*. (Liu 2015) similar results were obtained. Injection of CO_2 still is not investigated enough, and there is no precise information's about recovery rate of CH_4, percentage of CO_2 storage and stability of this mixture. There are several experiments conducted in the laboratories from which different results are obtained.

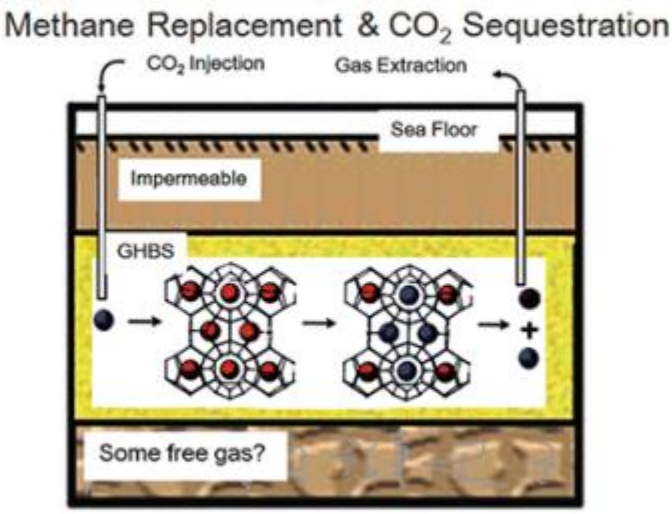

Figure 15 Methane replacement and CO2 Sequestration (Rajnish Kumar 2017)

In the study conducted by Zhao et al. injection of CO_2 in methane reservoir is described in two steps. First step was very short and it describes replacement of methane with carbon dioxide as surface replacement process between CO_2 and layer of hydrate while creating a layer of mixed CH_4-CO_2 hydrate.

Replacement in high pressure cell have been described by McGrail et al. (P. M. Mark White 2009) from which it is concluded that the rate of replacement for the first 200 min is fast.
Methane and carbon dioxide have different thermodynamic stability, and that is the reason why CO_2 is replacing the CH_4 in the cages of hydrates. According to Geng *et al*. (Geng CY 2009), the mixed CO_2-CH_4 hydrate formed after the replacement is the most stable hydrate compared to pure CO_2 and pure CH_4 hydrate. This is because the cages are filled perfectly in the mixed CO_2-CH_4 hydrate. The replacement of CH_4 by CO_2 as guest molecule in the gas hydrate structure is also has been proposed as a more elegant production technology with respect to greenhouse gas policies. (Christian Deusner 2012)

Injection of CO_2/N_2 mixture was tested in the Ignik Sikumi Gas Hydrate Field. During the first 13 days mixture of these gases ($6000m^3$) was injected in the reservoir, after which for the period of 2 days gas was produced using depressurization method.
In order to increase the effectiveness of CO_2 injection and to avoid the CO_2 injection problem at high pressures, 77 % N_2 and 23 % CO_2 mixture injection to gas hydrates was suggested by University of Bergen and it was proven experimentally and also in Ignik Sikumi field pilot project. (D. Schoderbek 2011)

6. HYDRATE PRODUCTION IN PERMAFROST

Huge volumes of methane hydrate are found in permafrost zones in the Arctic, it is estimated that about 500 to 1 200 000 Tcf (1.4 x 10^{13} to 3.4 x 10^{16} m^3) of methane hydrates are buried in the permafrost regions in the Arctic. (Lowrie 1996) Areas where gas hydrate can be found in permafrost are West Siberian, the Mackenzie Delta of Canadian Arctic, and the Northern Alaska.

Fields in the permafrost region where production activities are conducted are listed below:

- Mallik Field, Canada,
- Messoyokha Field, Russia,
- Alaska North Slope, USA.

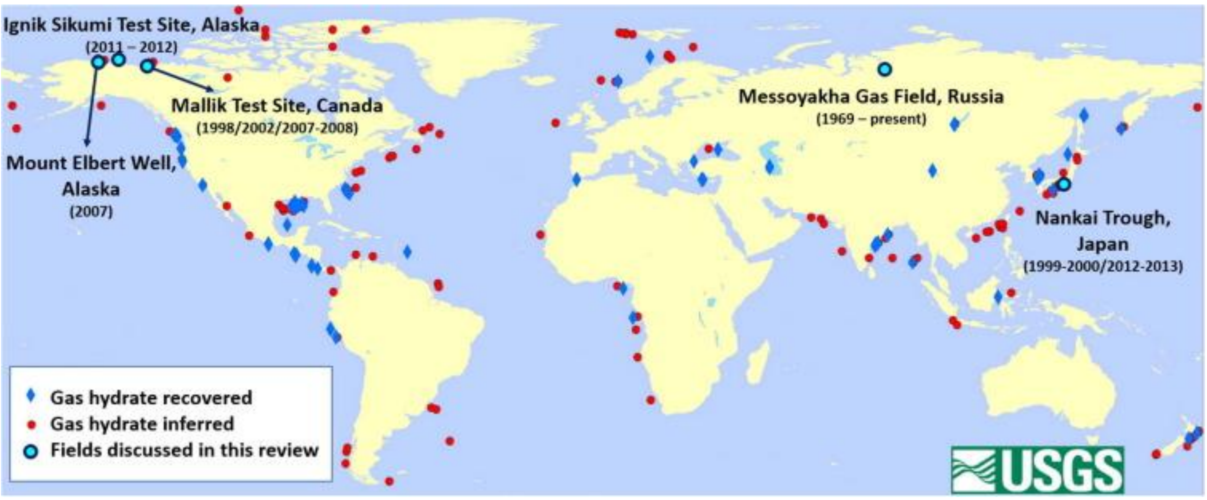

Figure 16 Locations of sites (Zheng Rong Chonga 2016)

6.1. Mallik

The Mallik Field is located in Mackenzie Delta of Canada. This site is an example of hydrate production in permafrost. In this field, three tests were conducted. Testing projects took place in 1998, 2002 and 2007-2008. In 1998, the Mallik 2L-38 research well was drilled. The purpose of this well was to evaluate the geologic controls on the occurrence of gas hydrate and for the first time acquire specialized core and well data needed to characterize the reservoir properties of a hydrate-bearing reservoir system. (Dallimore 1999) Because this project was successful, it opens a path for two new projects.

Mallik 2002 research well program was the first field study which includes actual production of gas from gas hydrate reservoirs. After that, one more study was conducted in 2007-2008.

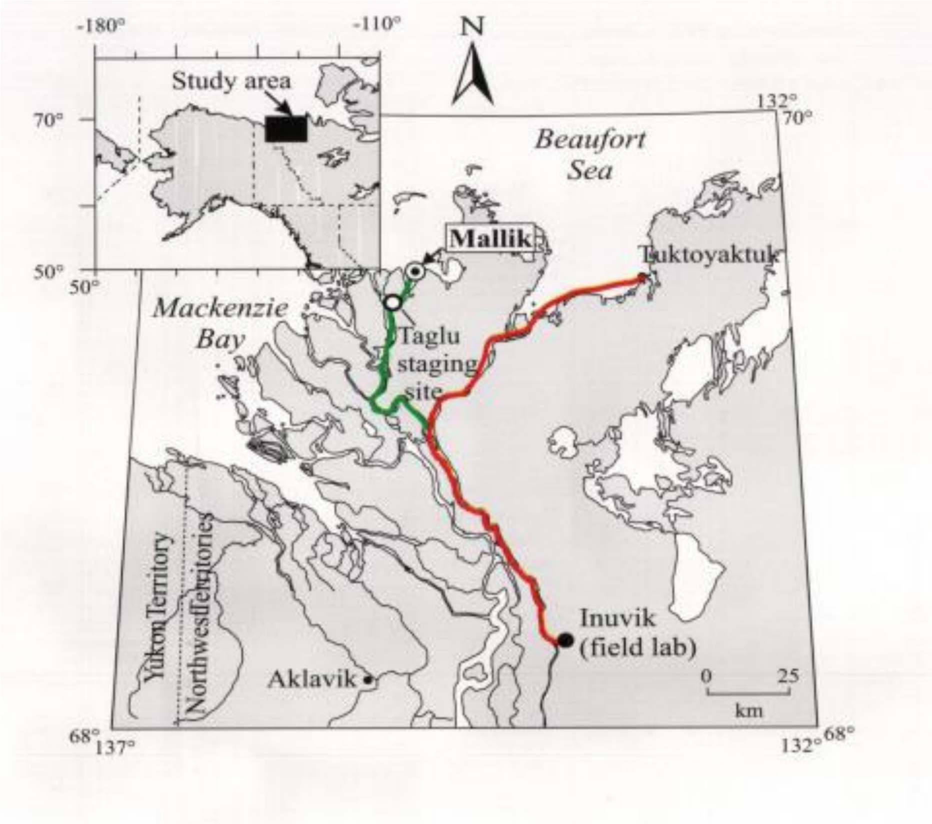

Figure 17 Location of the Mallik site

6.1.1. Background of the Mallik 2002

Gas Hydrate Research Well Program applied to Mallik 2002 site was to heat and depressurize *in situ* gas hydrate-bearing reservoirs. In order to produce critical gas hydrate reservoir data, and to use simulators for predicting the behavior of the gas hydrate reservoir when thermal stimulation and depressurization are applied, in 2002 at Mallik several production tests were conducted. The Mallik 2002 well provided the first scientifically documented evidence that gas could be produced from hydrates. (E. Dendy Sloan 2008) In 1998 at the Mallik site well 2L-38 provided data such as core and well-logs that confirm the existence of hydrates from 900 to 1100 m with *in situ* porosities of 35% and hydrate concentrations often above 80% of the pore volume. (E. Dendy Sloan 2008)

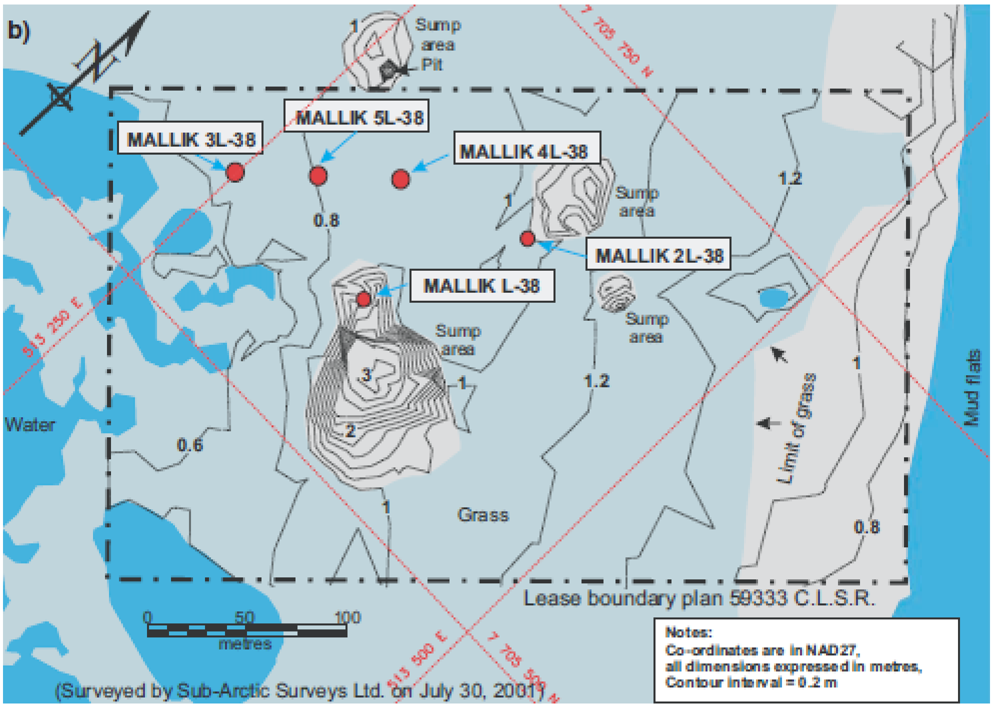

Figure 18 Location of the wells

Japanese National Hydrate Program in 2002 united with the Canadian Geological Survey to prove Mallik site in order to have evidence that gas hydrates could be produced. The drilling program started in December 2001 and it was finished in March 2002. Two observation wells (3L-38 and 4L-38) were drilled to 1188 m depth, coplanar with the 5L-38 main well, drilled to 1166 m. (E. Dendy Sloan 2008) Well logs were obtained from 885 to 1151 m in 5L-38. (Timothy S. Collett 2005) Three successful pressure stimulation tests were conducted. The thermal stimulation test was applied on a 13 m reservoir interval. (T. S. S.H. Hancock, Overview of thermal-stimulation production-test results for the JAPEX/JNOC/GSC et al. Mallik 5L-38 gas hydrate production research well 2005)

Three zones of gas hydrates were recognized:

- Zone A,
- Zone B,
- Zone C.

In total 110 m were observed in all three zones. The purposes of the Mallik 2002 drilling program were to conduct the production from gas hydrates and to develop model that will be used for forecasting the future production.

The first zone was Zone A from 892 to 930 m. The sediments of this zone were sand with the porosity of 32-38% where hydrates were occupying the larger pores of sediment.

Permeability of the sand where there are no hydrates was from 100 to 1000 mD, while in the zones where hydrates were present permeability was 0.1 mD. High saturation can be obtained in this region, it can reach the value of 80%.

The depth of Zone B is from 942 to 993 m, consisting of silt and sand, with porosity from 30 to 40%. In this zone, hydrates were occupying from 40 to 80% of the pore volume. In the zones without hydrates permeability was 1mD, while hydrates were 0.01 to 0.1 mD.

The last zone with a depth of 1070 to 1107 m in Zone C, which is consisted of silt with a porosity between 30% and 40% and saturation of hydrates between 80% and 90% of the pore volume. Permeability in silt was less than 0.1 mD.

6.1.2. Drilling parameters of the wells in Mallik Field

As it is previously said Drilling program started in December 2001 and it was completed in January 2002. Mallik 3L-38, 4L-38, and 5L-38 wells were drilled to be used for production tests. Distributed temperature survey cable and fiber-optic cable connected to the casing from outside were used. The cable was used to record temperatures of sediments and hydrate formation, the purpose of this was to find out under which temperature conditions gas hydrates will be stable. In January 2002 drilling of another well used for observation started. Gas released from the drilled sediments and hydrate layers was separated from re-circulated drilling mud and automatically analyzed for 12 different gases using three different analytical instruments.[5]

Drilling of the Mallik 5L-38, the main well, started on January 25, 2002. Drill cuttings were sampled every 10 m, samples for biogeochemistry were collected and mud gas sampling was continued as with the earlier hole. After a while, a coring operation was started at 886 m until the depth of 1166 m, and it was completed in 6 days with 48 lengths of core recovered. Open-hole logging was used successfully.

[5] https://netl.doe.gov/node/7489

For drilling mud was used lecithin-water, whose density is near 1082 kg/m^3 in order to maintain stability of wellbore in gas hydrate and permafrost sections. There were no difficulties with keeping the temperature of drilling mud close to the temperatures of gas hydrate interval in the permafrost area.

Temperature between 0 and 650 m in some depths is below 0°C, which is proving the permafrost area. In the permafrost region, the increase in the temperature of the drilling fluid in some locations caused faster drilling. The slow rate of penetration between 0 and 650 m was due to the drilling of frozen permafrost sediments. (Ş. Merey, Evaluation of drilling parameters in gas hydrate exploration wells 2019)

The temperature in Mallik 3L-48 and 4L-48 is changing from 0°C to 4°C below 400 m, while in Mallik 5L-38 temperature is all the time near to freezing points. Below 400 m in Mallik 3L-38 and 4L-38 rate of penetration has been increased, while the weight on the bit has been decreased from 600 m until 800 m.

The concentration of CH_4 with mud logging analysis was recorded for all wells. It can be seen that the concentration of CH_4 in drilling mud is increasing below 800 m. This is a proof that gas hydrates are located in these sediments. In this area the rate of penetration is also decreased, even though the weight on the bit is increased. The density of drilling fluid decreased in Mallik 4L-38 and 5L-38, while in Mallik 3L-48 it has been increased. When Mallik 5L-38 is observed, it can be seen that resistivity below 800 m is high, and this is a confirmation of a high concentration of CH_4 in the drilling mud, not only in 5L-48 well but in all wells due to gas hydrate existence. There is no change in the borehole diameter of the Mallik 5L-48 in the gas hydrate section, which can be seen from the caliper log. If the selection of rpm, drilling fluid type is selected properly, this increases possibility for success of drilling operations. (Figure 21)

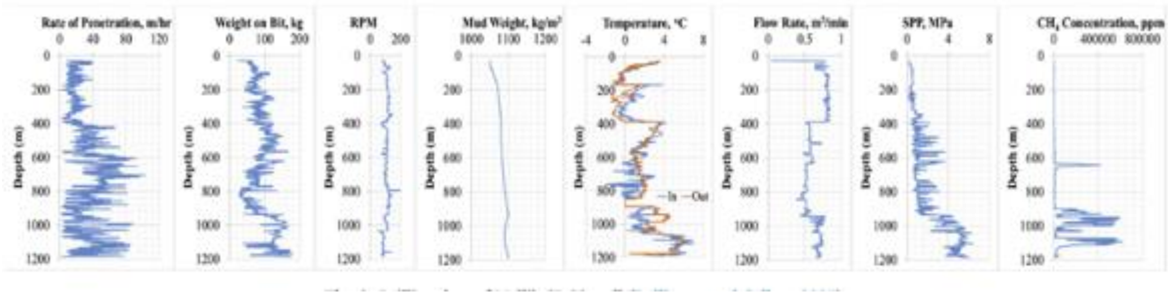

Figure 19 Drilling data of Mallik 3L-38 well (Ş. Merey, Evaluation of drilling parameters in gas hydrate exploration wells 2019)

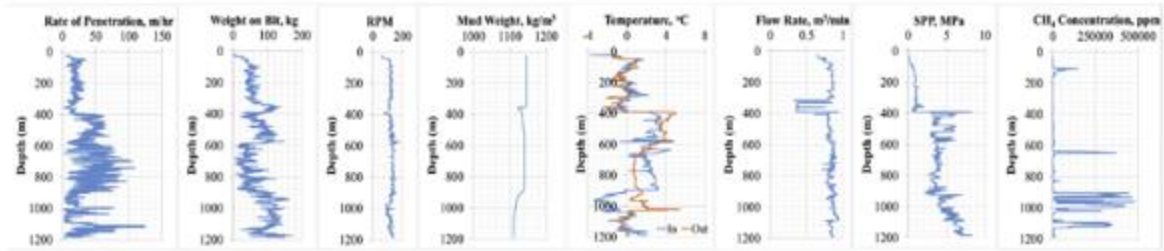

Figure 20 Drilling data of Mallik 4L-38 well (Ş. Merey, Evaluation of drilling parameters in gas hydrate exploration wells 2019)

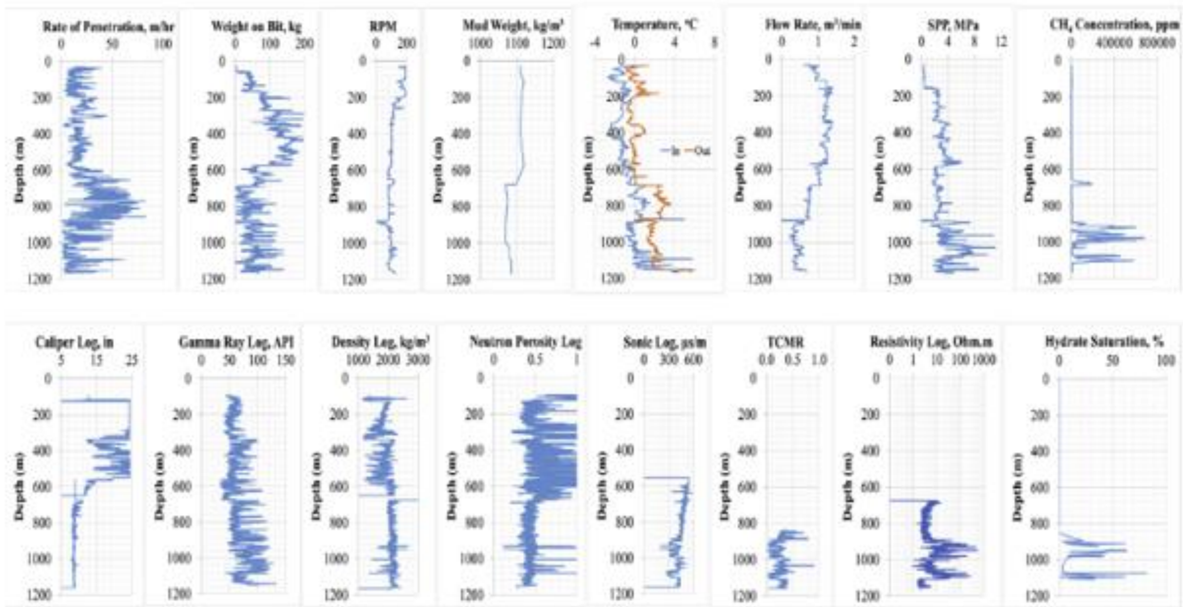

Figure 21 Drilling and log data of Mallik 5L-38 well (Ş. Merey, Evaluation of drilling parameters in gas hydrate exploration wells 2019)

If we compare the data from Figure 19 and Figure 20, from which drilling data of Mallik 3L-38 and 4L-38 can be seen, it can be concluded that there is a huge similarity between these two wells, and the reason is that these wells are close to each other and the lithology is pretty much the same.

Drilling in the area of hydrate zones, such as the Mallik site could be very risky because there are many complications that can occur during this operation. Formation of new gas hydrates inside the well and plugging perforation or unexpected dissociation can affect stability of the well. However, the wells drilled in the Mallik site were successful, and it is shown that dissociation didn't happen immediately so it didn't affect the stability.

Most of the problems were similar to those happening in conventional reservoirs. During drilling in this type of reservoirs, focus should be on drilling fluid selection in order to keep the formation stable.

6.1.3. Pressure stimulation tests in the 5L-38 well

Three MDT tests (Modular Formation Dynamics Tester) were conducted successfully in the Mallik 5L-38 well. After these tests, the most important information that has been known as a proof of hydrates from the response of the reservoir to pressure simulation and geomechanical/geothermal measurements at the pressure production interval. To illustrate the hydrate dissociation pressure response, consider the evidence of hydrates from one pressure stimulation test (MDT-2) at 1090 m depth in hydrate Zone C. (Figure 22)

In MDT-2, before perforations were done, all wells were sealed at the top and the bottom. In the first 8h three pressure simulations were performed (E. Dendy Sloan 2008):

- During a period of 30 min, first, for 8 min. gas was removed in order to reduce the pressure, then, during a period of 25 min, hydrates were dissociated and the pressure increased.
- Equally, in 1hour and 20 min the pressure was decreased for 37 min, and hydrates which have been dissociated restored the pressure in the next 69 min. Pressure could be modeled from reservoir permeability indications, in the range from 0.001 to 0.1 mD.

- Few moments before the 3h mark, the pressure was decreased for 16 min, and hydrates which have been dissociated reloaded the pressure in the next 190 min, until around 6 h and 25 min.

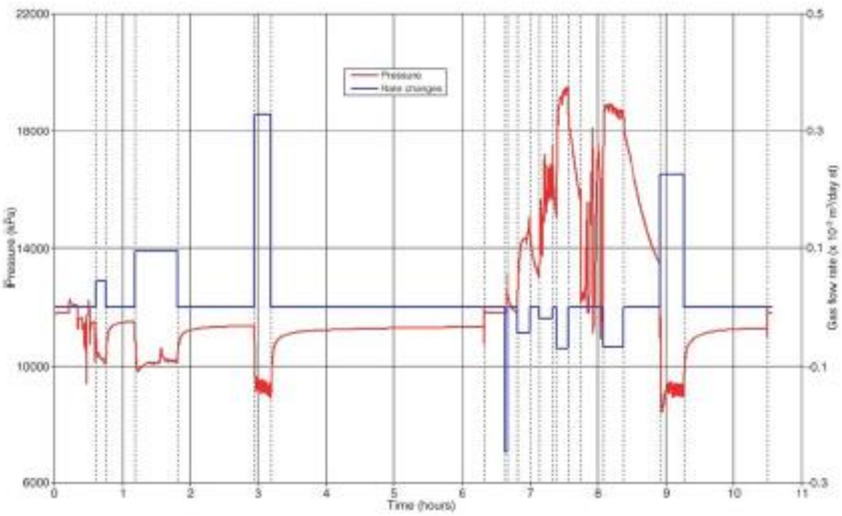

Figure 22 Mallik 2002 pressure stimulation test 2 at 1090 m, showing the initial three flow and shut-in sequences, 3 fractures sequences, and a final flow and shut-in sequence (T. S. S.H. Hancock, Overview of thermal-stimulation production-test results for the JAPEX/JNOC/GSC et al. Mallik 5L-38 gas hydrate production research well 2005)

After 7h until 8h, in the reservoir well fluids were pumped in order to cause microfractures. Ultimately, a few moments before 9h in Figure 22, the interval flowed for 21 min, and the pressure rebuilt over the next 76 min, to determine the permeability increase due to the previous microfractures. (E. Dendy Sloan 2008)

6.1.4. The Thermal stimulation test in Mallik 5L-38

At the Mallik 5L-38 gas hydrate well the thermal-stimulation test was conducted where the objective of the test was to detect the dissociation of a gas hydrate interval where the temperature was above the stability point, while the pressure was kept constant. The results of this test could be used for calibration of numerical-simulation models to determine the in situ kinetic and thermodynamic properties of the gas hydrate. (Tohru Satoh 2005). Zone A was used for the thermal stimulation test. Well flow blockers were installed above the 907m and below the 920m.

This interval consisted of sandstone with 70 to 80% saturation with gas hydrates, with a conglomerate layer from 913 to 915 m with gas saturation of 50%. Shale was an upper boundary of the thermal-test zone with a thickness of two meters, while the lower boundary was shale with one-meter thickness. The test interval was perforated from 907 to 920 m. DST was used to observe the perforation event through thermal and mechanical effects. The temperature increased along the perforations which can be seen from Figure 23.

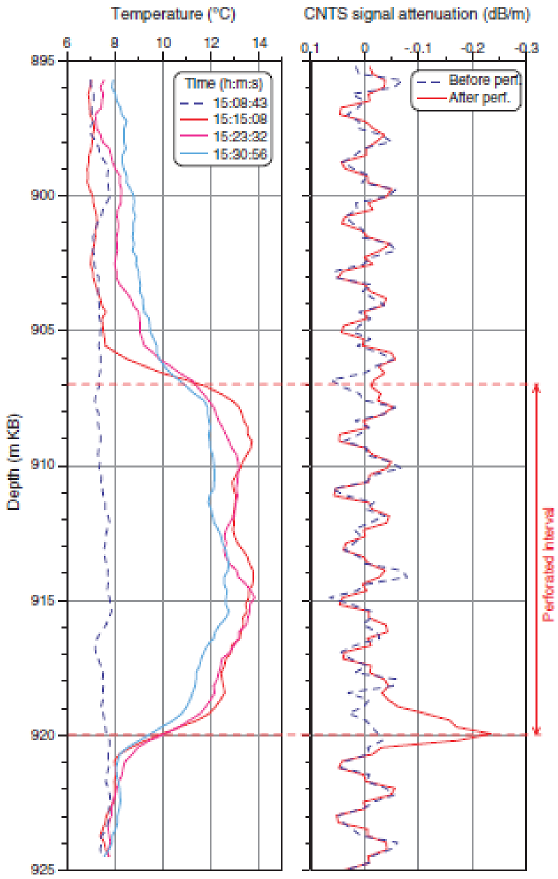

Figure 23 Distributed temperature sensor (DTS) response during perforation, JAPEX/JNOC/GSC et al.Mallik 5L-38 gas hydrate production research well.

The increased attenuation at the top and bottom of the perforated interval is attributed to mechanical stress, which was exerted on the DTS sensor cable as a result of the instantaneous pressure pulse associated with perforating. On the basis of the observed changes, the DTS depths could be correlated with the log and core depths for the well. (Timothy S. Collett 2005) A small amount of gas hydrate was dissociated due to the thermal pulse of the perforation, but free gas was not detected at the surface. There was no fluid loss or gain in the period between perforation and the thermal test.

6.1.4.1. Surface facility operation

For stimulation of this gas hydrate interval, the closed-loop process was used (Figure 23). The brine was heated and from the wellhead was injected down a circulating string. It was circulating through the perforation and it was returned to the surface with produced gas. At the surface, separators were used to separate produce gas from the fluid.

Therefore, gas was measured, while circulating fluids were transferred into an atmospheric tank and treated in order to be used for another cycle. During the thermal test (123.65 hours), the well was circulated approximately 630 times, and the entire fluid volume was circulated approximately 53 times. (T. S. S.H. Hancock, Overview of thermal-stimulation production-test results for the JAPEX/JNOC/GSC et al. Mallik 5L-38 gas hydrate production research well 2005)

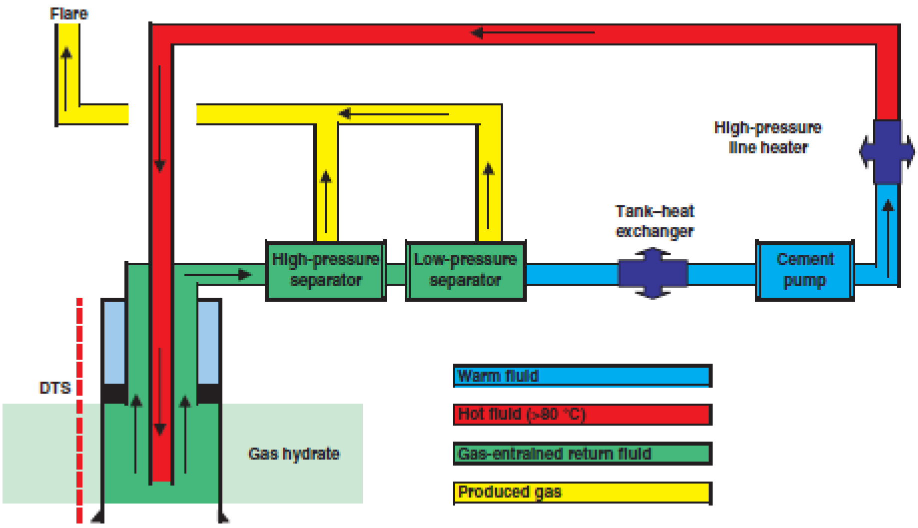

Figure 23 Schematic diagram of the thermal-test process, JAPEX/JNOC/GSC et al. Mallik 5L-38 gas hydrate production research well (T. S. S.H. Hancock, Overview of thermal-stimulation production-test results for the JAPEX/JNOC/GSC et al. Mallik 5L-38 gas hydrate production research well 2005)

6.1.4.2. Circulation rates, pressures and temperatures

From Figure 24 surface injection and surface return temperature can be observed, and surface volume and circulation rate as well. The start of the circulation is time zero. (Timothy S. Collett 2005) The difference between surface-return temperature with the injection temperature was 10°C, a heat loss expected due to the use of non-insulated tubing strings. Gas was detected at the surface after 2h. At 20h circulation system was shut down, and restored at 22h. The surface temperature dropped 10°C due to the power failure and was again restored around 66h. Around 90h, the surface temperature was decreased in order to reduce the liquid in the gas lines. A significant temperature drop happened at 103h because of an electrical system problem. The surface volume inventory was differing from ±5 m^3. Surface-injection pressures were generally in the 13,000 to 14,000 kPa range.

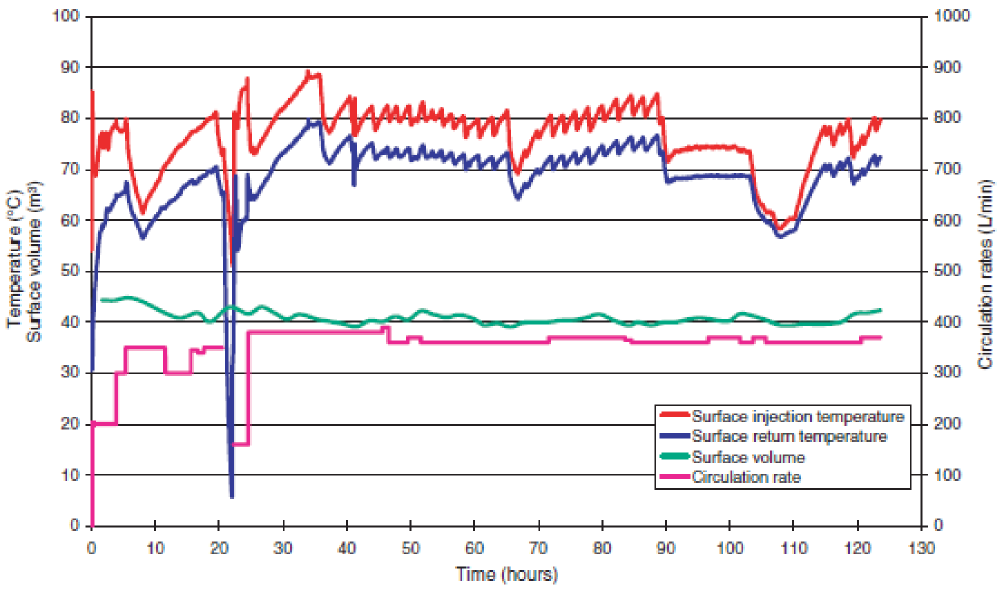

Figure 24 Surface temperatures, surface volume, and circulation rate during thermal stimulation of the JAPEX/JNOC/GSC et al. Mallik 5L-38 gas hydrate production research well (T. S. S.H. Hancock, Overview of thermal-stimulation production-test results for the JAPEX/JNOC/GSC et al. Mallik 5L-38 gas hydrate production research well 2005)

6.1.4.3. Surface gas production

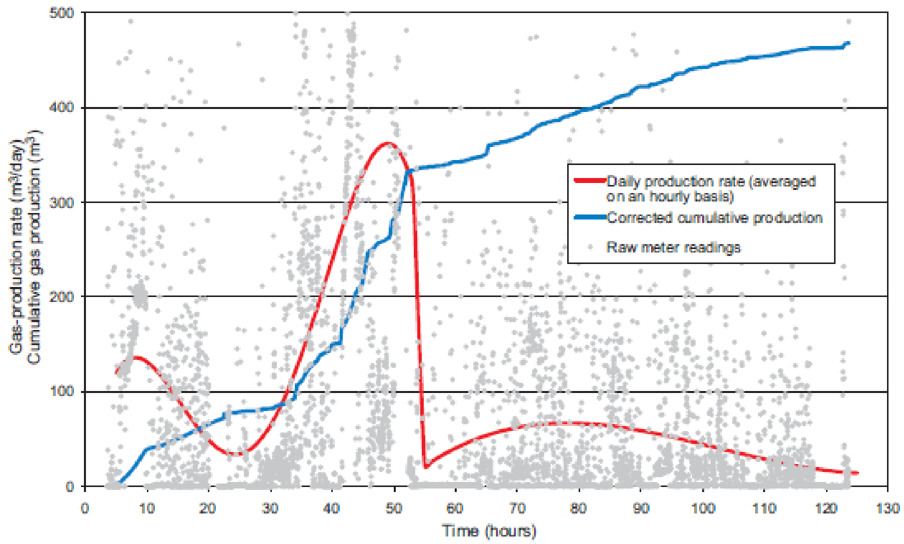

Figure 25 Gas production during thermal stimulation of the JAPEX/JNOC/GSC et al. Mallik 5L-38 gas hydrate production research well. (T. S. S.H. Hancock, Overview of thermal-stimulation production-test results for the JAPEX/JNOC/GSC et al. Mallik 5L-38 gas hydrate production research well 2005)

During the thermal-stimulation, gas rates were measured with the mass-flow meters at one-minute intervals. In Figure 25, average gas production versus time and cumulative gas production can be seen. If daily production rate is observed it can be noticed that there are three production peaks, around 10h, 45h and 80h. At the end of the thermal-stimulation test, the cumulative gas production was 468m^3. (Timothy S. Collett 2005) In order to stabilize the well, circulation has been stopped and well was left to cool.

6.1.4.4. Fluid samples

The mass spectrometer, a gas chromatograph, and a radon detector were used to analyze the produced gas during the thermal-stimulation at the Mallik site in the 5L-38 well. The gas which has been sampled and was predominant was methane.

Samples were collected as follows (Timothy S. Collett 2005):

- 26 samples of gas were pressurized (500 cm^3) from the high-pressure separator,
- 94 samples of gas were pressurized (75 cm^3) from the high-pressure separator, after which were sampled in atmospheric containers in order to conduct isotope analyses,
- In order to conduct the analysis for the potassium and chloride concentrations, 99 samples were collected,
- In order to conduct the analysis of chemical tracer, 36 sample pairs of circulation fluid were collected,
- In the end 2 samples of solids/mud were collected from the high-pressure separator.

6.1.5. Modeling gas production from hydrates

In order to forecast long-term production for Mallik 2002, several scientists developed models that were used to fit actual production data. There are three models that are developed:

- Moridis et al. 2005 model (George J. Moridis n.d.)
- Kurihara et al. 2005 model (Masanori Kurihara 2005)
- Hong and Pooladi-Darvish 2005 model (Pooladi-Darvish 2005)

Moridis et al.) developed a model for the thermal test. The name of the model was LBNL (Lawrence Berkeley National Laboratory). Kurihara et al. developed a model for thermal-stimulation and pressure-stimulation tests, the model is also called JOE (Japan Oil Engineering Co., Ltd.). Hong and Pooladi-Darvish model were used for production prediction.

In the LBNL model for the thermal test, it is shown that heat-transfer-limited hydrate dissociation rather than the kinetics of hydrate dissociation. The progress of the thermal wave to the hydrate interface was limited by a low hydrate thermal conductivity, so that hydrate kinetics were insignificant. (E. Dendy Sloan 2008)

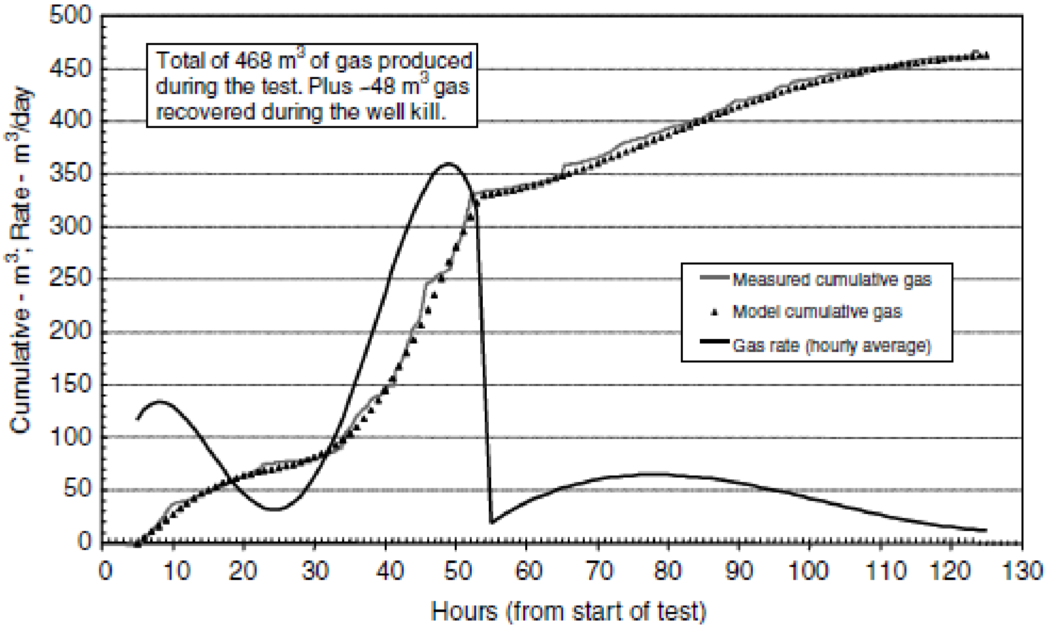

Figure 26 Mallik 5L-38 gas production on the thermal test. (T. S. S.H. Hancock, Overview of thermal-stimulation production-test results for the JAPEX/JNOC/GSC et al. Mallik 5L-38 gas hydrate production research well 2005)

Five zones were investigated, properties of the zones were: porosity 28%, permeability 20mD, the specific heat of the rocks 800 J/kg ^{o}C and specific heat of the hydrate was 1600 J/kg ^{o}C.

The numerical codes used for production prediction were TOUGH2 general-purpose simulator for multi-component, multiphase fluid and heat flow and transport in the subsurface with the EOSHYDR2 module. (G. J. Moridis 2007) EOSHYDR2 can model the non-isothermal methane release, phase behavior and flow under conditions typical of methane-hydrate deposits (i.e., in the permafrost and deep ocean sediments) by solving the coupled equations of mass and heat balance. (George J. Moridis n.d.)

Moridis et al., concluded that production from Zone 1 is possible with depressurization, from Zone 2 is also possible with depressurization but with producing a huge amount of water, in Zone 3 thermal stimulation yields measurable amounts of dissociated gas.

Kurihara et al., summarized in Figure 27 gas production for 5 days and for 10 years. Four methods are applied: hot-water circulation, depressurization, combined depressurization, and hot-water circulation and partial hot water injection. During the five-day period, by these methods respectively gas production volumes were predicted 463, 1728, 3489 and 4510 m^3. It can be seen that only a small amount of gas can be produced using the hot-water circulation if five days and 10 years tests are observed.

Using the partial hot-water injection the highest amount of produced gas (2.42 x 10^6 m^3 at SC) can be reached over ten years. However, depressurization does appear to be a favorable production mechanism, comparing favorably to hot water circulation with reduced bottom hole pressure, or partial hot water injection. (E. Dendy Sloan 2008)

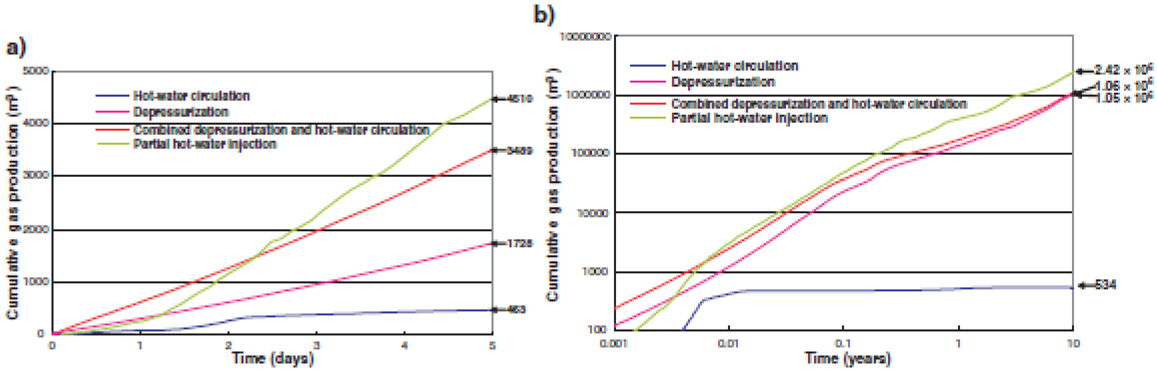

Figure 27 Predictions of long-term gas-production performance, from the JAPEX/JNOC/GSC et al. Mallik 5L-38 gas hydrate production research well, of four prediction methods for a) five days, b) ten years (Masanori Kurihara 2005)

Hong and Pooladi-Darvish developed a numerical model for studying the potential of depressurization method for gas production from gas hydrate reservoirs. Their results indicated that a huge amount of gas can be produced with this method if gas-rate is adjusted so that the gas from hydrate decomposition would sustain the reservoir pressure and allow further production.

6.1.6. Conclusion

In Mallik site three tests were conducted. Three zones of hydrate layers were observed and two different production methods were applied. Both, pressure stimulation and thermal stimulation were conducted using 5L-38 well drilled in 2002. Zone A was used for the thermal stimulation test which was long 123,65h, while Zone C was used for pressure stimulation test, long 11h. Cumulative production after thermal stimulation measured at surface was 468m3. As a primary goal, to verify existence of hydrates and to prove possibility of producing gas from this type of reservoirs, it is succeeded. But currently, production from gas hydrate reservoirs cannot be comparable with conventional gas production.

6.2. Messoyakha

Messoyakha Gas Field is located in Siberian permafrost, Russia. Production on this field started in 1970, and it was the first discovered gas hydrate field. Messoyakha consists of a free gas zone and layer of hydrate above it, while under the free gas zone, an aquifer is located. This is the only field where long-term production takes place in an area of gas hydrate reservoirs. More than 60 wells have been drilled in this field. There hasn't been enough information in the literature about the exact percentage of reservoir portion filled with hydrates. Initial hydrate saturation is described to be about 20%. (Makogon 2005)

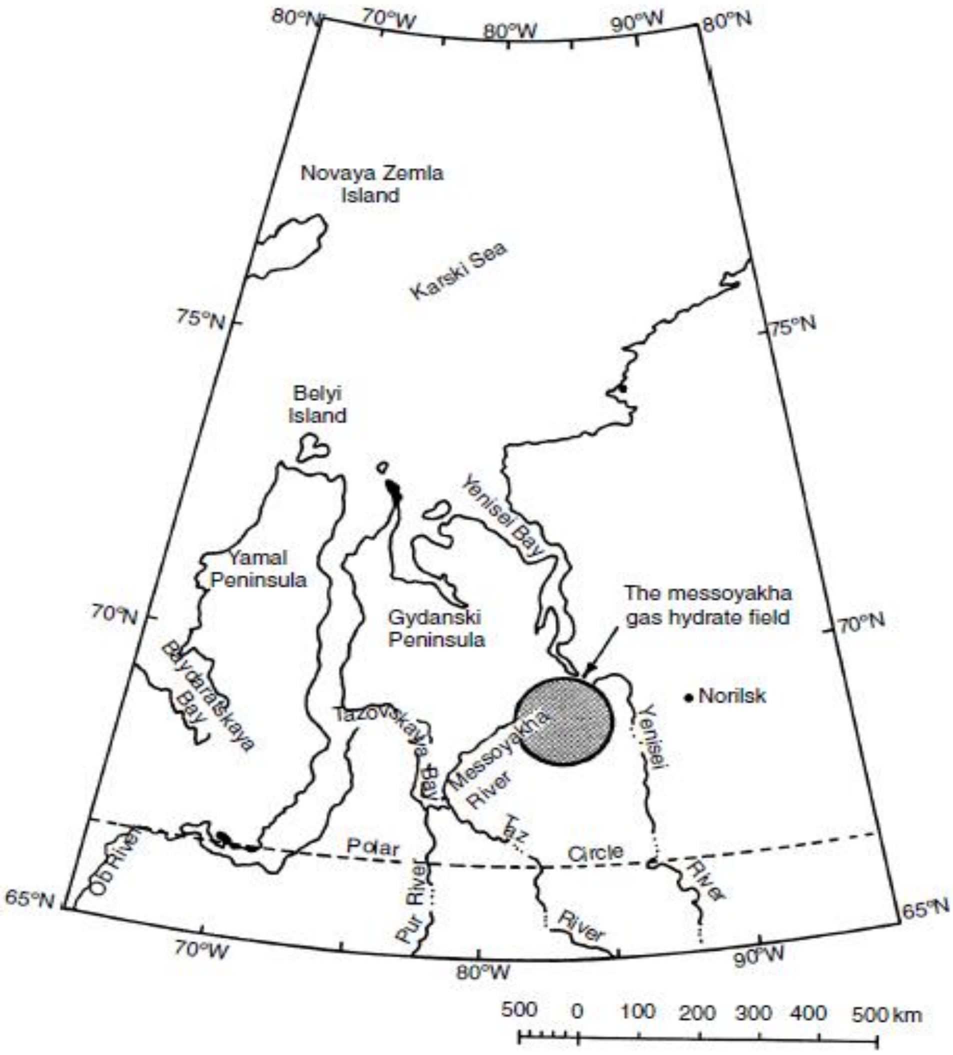

Figure 28 Location of the Messoyakha Gas Field (E. Dendy Sloan 2008)

6.2.1. Background of Messoyakha

A cross-sectional schematic of Messoyakha is shown in Figure 28, from which also can be seen that the reservoir is located in an anticlinal structural trap. The thickness of the permafrost zone is 420-480m. In a sandstone formation Dolgan, producing intervals are located. Above the sandstone, there is a layer of the shale, but the sandstone is also interbedded with shale steaks. The gas can be found both in the free and in a hydrate state. Messoyakha gas field is described as a hydrate capped gas reservoir, i.e. the upper portion of the reservoir contains gas in hydrate state and the lower portion of the reservoir contains free gas. Area of the pay zone of the Messoyakha field is 12,5km, thickness 84m, average porosity 25%, average water saturation 40%, initial reservoir pressure 7,8MPa and temperature of 285K.

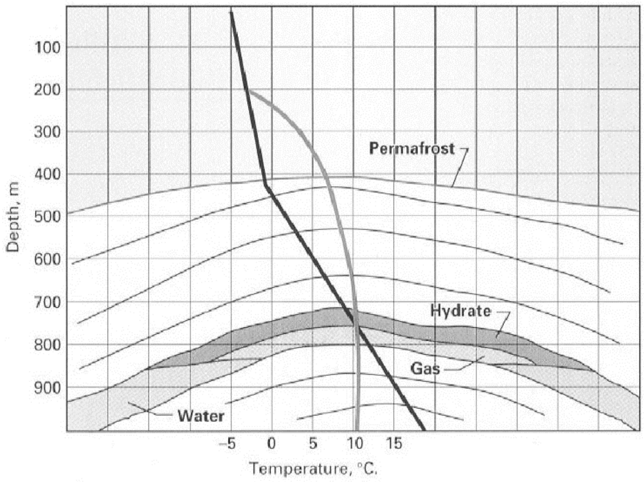

Figure 29 Cross-section of Messoyakha Gas Field (Makogon 2005)

The scientists involved in studying hydrates claim that the Messoyakha field contains gas hydrates due to initial pressure and temperature of the reservoir (P = 7.7MPa, t = 8 to 12°C or P=1128 psi, t=46-54 F) that are within the gas formation window. (Makogon 2005)

The development of the Messoyakha can be divided into five periods. From the Figure 30, it can be seen that for the 35 years of production pressure decreased from 7.7MPa to 6MPa. During the first period, from the beginning of production until 1971, pressure decreased because of the high rates of gas production. In the next period, the process of hydrate decomposition started occurring until 1975.

In the third period, until 1977, the pressure remained constant which was the consequence of decomposition of hydrates, volume of gas which was released from gas hydrates replaced already produced volumes. After that, the field was shut in for three years. Decomposition during this time continued to occur, and reservoir pressure increased to 6MPa. Later, from 1982, production was very low compared to the previous times, and it did not exceed 400x10^6 m^3/year. The gas volume produced from the reservoir approximately corresponded to the volume of hydrate gas entering due to dissociation of hydrates. (Y.F.Makogon 2013)

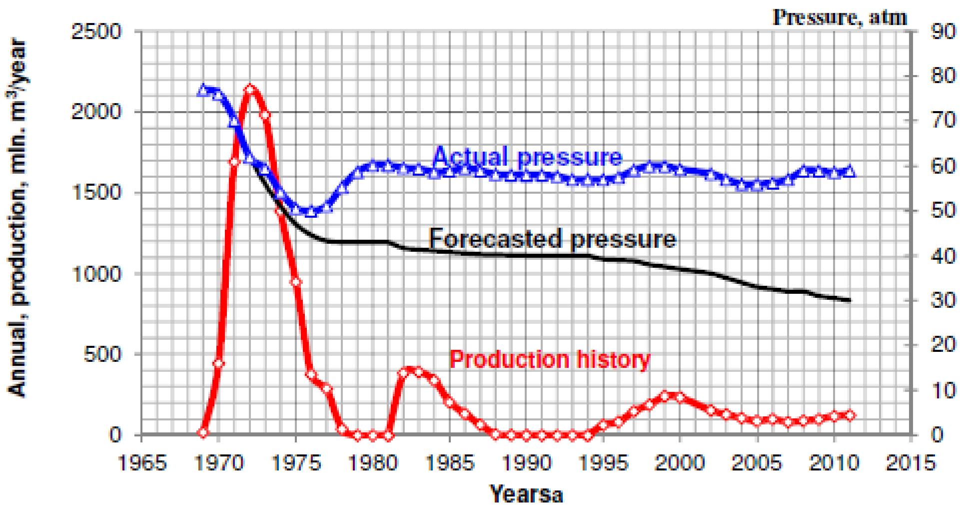

Figure 30 Reservoir pressure response due to production from Messoyakha reservoir (Y.F.Makogon 2013)

6.2.2. Production

As it is mentioned, 60 wells have been drilled in this field. Production has been obtained from a depth interval between 720 m and 820 m. The upper part of the reservoir, thick approximately 40m, is located in the methane hydrate stability zone. Wells are perforated in the hydrate area and the area of the free gas. Production from the free gas zone was significantly higher than from hydrate section. Gas hydrate occurrence was proven for the first-time during production tests conducted in the upper part of the reservoir, where low gas rates were achieved. (Table 6 and Table 7)

Table 6 Inflow Performance of The Messoyakha Wells from The Top Section of The Reservoir (F. Makogon 1997)

Well number	**Test interval**	**Fluid**	**Production rate**		
	Depth (m)		Gas rate 10^3 (m3/day)		Water (m3/day)
1	826-837	Gas + water	28,3	-	-
5	810-820	Water + gas	Weak inflow	-	50
6	832-838	gas	3,2	-	-
117	843-851	water	-	-	-
121	815-826	Gas + water	15,8	26,2	-
123	830-843 845-854		8,6	-	-

Table 7 Well Productivity Comparison of Wells Completed in the Free-Gas and Gas Hydrate Zones (F. Makogon 1997)

Well number	**Absolute depth**	**Distance to the perforations**	**Open flow potential**
121	-716-727	64	26
109	-748-794	6	133
150	-741-793	-6	413
159	-779-795	-29	626
131	-771-793	-59	1000

The same scenario occurred after depressurization, where the wells perforated in the lower zone of the free gas zone were producing normally, while during depressurization in the hydrate zone, dissociation of the hydrates happened, which caused the decrease in temperature in the surrounding area and the water and gas created new hydrates near the well, which caused plugging of perforations. Chemicals such as methanol and calcium chloride were used in the wells perforated in hydrate zones. By using this type of stimulation, hydrates created near the wells were melted.

Table 8 Productivity Increase After Methanol Treatment in the Well #133 and 142 (F. Makogon 1997)

	Before treatment		**After treatment**	
	Draw-down pressure (atm)	Production rate 103 (m3/day)	Draw-down pressure (atm)	Production rate 103 (m3/day)
133	3,5	25	0,4	50
	7	50	0,8	100
	14	100	1,1	150
	19	150	1,5	200
	22	200	2	250
142	8	5	0,4	50
	13	10	0,5	100
	19,5	25	0,7	150
	25	50	1	200
	30	100	1,4	300
	33	150		

6.2.3. Modeling gas production from hydrates

One of the simulators used for production prediction of the Messoyakha field is the TOUGH+HYDRATE numerical simulator developed at Lawrence Berkeley National Laboratory in the USA, by Moridis 2005. TOUGH+HYDRATE is used for simulation of the behavior of hydrate-bearing porous media. This simulator can be used for modeling non-isothermal gas release by hydrate dissociation, heat transfer in porous media, stimulation methods such as depressurization, thermal injection, injection of inhibitors and their combinations, it can track released gas by dissociation.

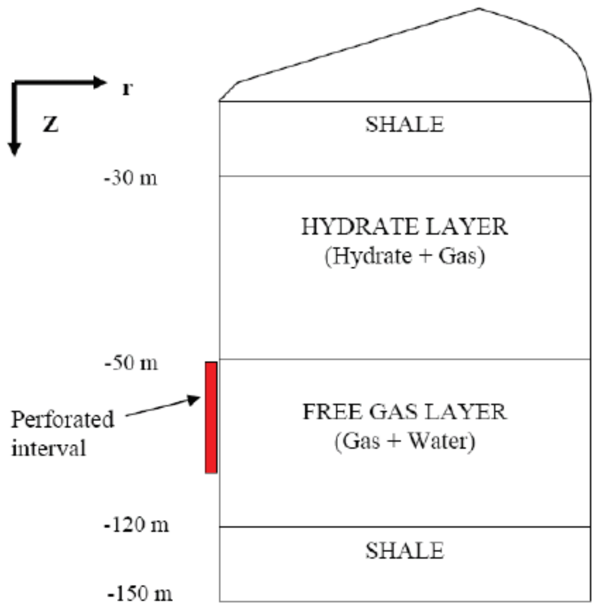

Figure 31 Representative geometry of Messoyakha Reservoir (Tarun Grover 2008)

Class of hydrate reservoir was defined in order to set-up a model in this numerical simulator, where Messoyakha is described as a Class 1 hydrate reservoir because the hydrate layer consists of gas and hydrate underlain by free gas and water layer. This class of hydrate reservoir is known as the most desirable because at the same time gas can be produced by conventional methods, while the dissociation of hydrates will keep reservoir pressure constant for a longer time. Messoyakha was modeled as a 2-D radial cross-sectional model. To analyze the primary results, the base model was set, which was based on previous simulation models of hydrates. Also, some assumptions like zero salinity and Initial pressure at the hydrate-gas interface (7.9MPa) were taken into consideration. (Moridis and Kowalsky, 2005) introduced the concept of “Volume replenishment Ratio (VRR)” for production from Class 1 hydrate reservoirs, where:

$$\text{VRR} = \frac{\text{Cumulative gas released in the reservoir by hydrate dissociation}}{\text{Cumulative gas produced}}$$

Properties used in the simulator were: Thickness, porosity, gas production rate, initial hydrate saturation, initial gas saturation, water saturation, irreducible water saturation, absolute permeability, relative permeability model (Modified Stone's first three-phase model) and Capillary pressure Model (Van Genutchen function).

Equation 7 Modified Stone's first three-phase model

$$k_{ra} = \min\left\{\left[\frac{S_a - S_{ira}}{1 - S_{ira}}\right]^n, 1\right\}$$
$$k_{rG} = \min\left\{\left[\frac{S_G - S_{irG}}{1 - S_{ira}}\right]^n, 1\right\}$$

Equation 8 Van Genutchen function

$$P_{cap} = -P_0\left[\left(S^*\right)^{-1/\lambda} - 1\right]^{-\lambda} \text{ with restriction } -P_{max} \le P_{cap} \le 0$$
$$S^* = \left[\frac{S_a - S_{ira}}{S_{mxa} - S_{ira}}\right]$$

Several sensitivity analyses were conducted, such as Sensitivity to hydrate layer permeability, Sensitivity to absolute permeability in the free gas layer and Sensitivity to well completion interval. The average pressure in the free gas layer (FGL) is plotted as a function of time, and it is increasing when the well is shut off. The hydrates experience the higher-pressure differential caused by a higher depletion rate in the free gas zone as compared to that in the hydrate zone. This is very similar to the pressure behavior observed at the Messoyakha field. Figure 32 shows the pressure rising at the time of the shut-in of the well. (Tarun Grover 2008)

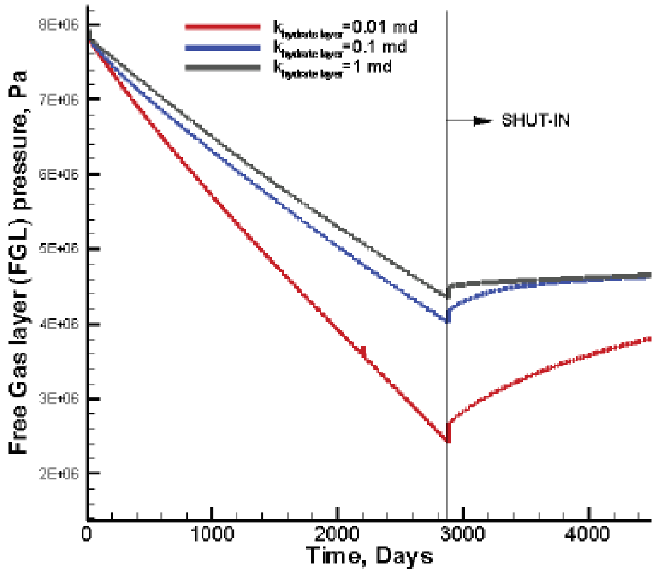

Figure 32 Sensitivity to hydrate layer permeability (Tarun Grover 2008)

Grover et al. 2008 concluded:

- The pressure increases in the reservoir due to continued hydrate dissociation is an important phenomenon.
- Water drive in a hydrate capped gas reservoir is not beneficial for producing gas from hydrates.
- If the perforations are deep inside the hydrate zone as compared to that in the free gas zone, they can give rise to high-pressure drops.
- In a hydrate capped gas reservoir, the permeability of the free gas zone becomes a limiting factor if the perforations are located near the hydrate-gas interface.
- The ultimate aim of producing from a hydrate capped gas reservoir should be such that the gas release rate of hydrate dissociation in the reservoir should be as close as possible to the well production rate.

Makagon and Omelchenko 2013 conducted a study that uses four models of the Messoyakha field structure and examines them using CMG STARS and IMEX software packages. These software packages were used to calculate gas production from a hydrate-bearing formation. It has been previously shown that the STARS simulator can be used to model hydrate decomposition. The distribution of reservoir properties is created within a 3D geological grid. The assumption that the Messoyakha field is a volumetric gas reservoir was taken. The aim was to match pressures with production rates in history. Actual gas production and results created by the model are shown in Figure 33:

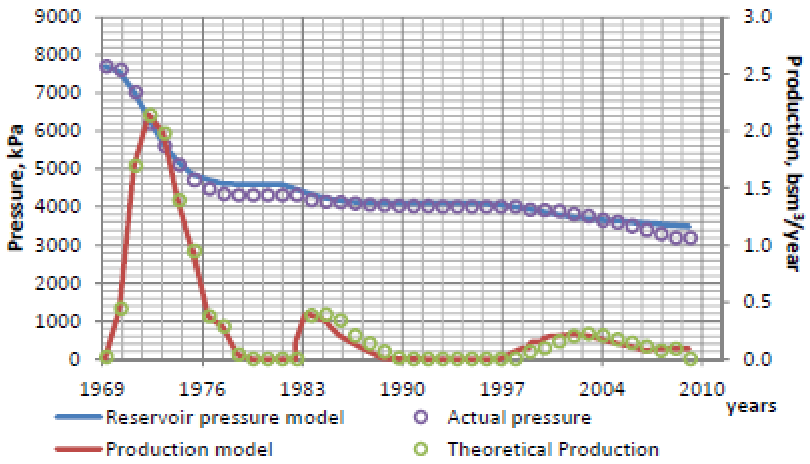

Figure 33 Actual field data compared with the results obtained by the model (Y.F.Makogon 2013)

As can be seen from the figure above, matching the model with actual reservoir pressure was good, this model can be used for further study of pressure support mechanisms.

Different solution scenarios were used in this study (Makagon and Omelchenko, 20013) such as application of gas injection wells for pressure support, application of simultaneous water and gas injection for pressure support and application of a no isothermal simulator for the pressure support.

6.2.4. Conclusion

As it is already said, Messoyakha gas field is only field of gas hydrates where long-term production was conducted. In the first years of production amount of gas reached maximum, after which from 1982, production was very low compared to the previous times, and it did not exceed $400x10^6$ m^3/year. Since, free gas zone was located above gas hydrate layers, gas was produced from both zones. Higher amount of gas was produced from free gas zone, while during producing from hydrate zone using depressurization method problems of creating hydrates near wellbore appeared. In order to solve the problem, inhibitor injection was applied. This problem could be possible in other gas hydrate fields in permafrost zones and combination of inhibitor injection with depressurization can be good solution, but it will for sure increase cost of production.

6.3. Alaska North Slope

Evidence for the occurrence of gas hydrates comes from the analysis of cores and downhole logs from an industry test well and two government-sponsored gas hydrate test wells: The Mount Elbert, and Iġnik Sikumi wells. (T. S. Collett 2019) Mount Elbert Gas hydrate site is located in the north of Alaska, in the Milne Point Field near the Prudhoe Bay oil field. In December 2018, drilling operations finally confirmed the presence of two high-quality reservoirs saturated with gas hydrates. (T. S. Collett 2019) The Mount Elbert site became the first gas-hydrate prospect on the Alaska North Slope investigated mainly from seismic analyses and nearby downhole geophysical data. (Lee 2011) This site is made up of coarse-grained sand, which is permeable and with adequate porosity for hydrates to form. The depth of the reservoir is in the zone where pore pressure is suitable for creating hydrates and the thermal gradient does not exceed the value that will interrupt stability.

Coring, logging, and formation pressure tests were applied in the Mount Elbert Test Well, and the first data collection on the geologic controls on the occurrence of gas hydrates in northern Alaska was provided from it.

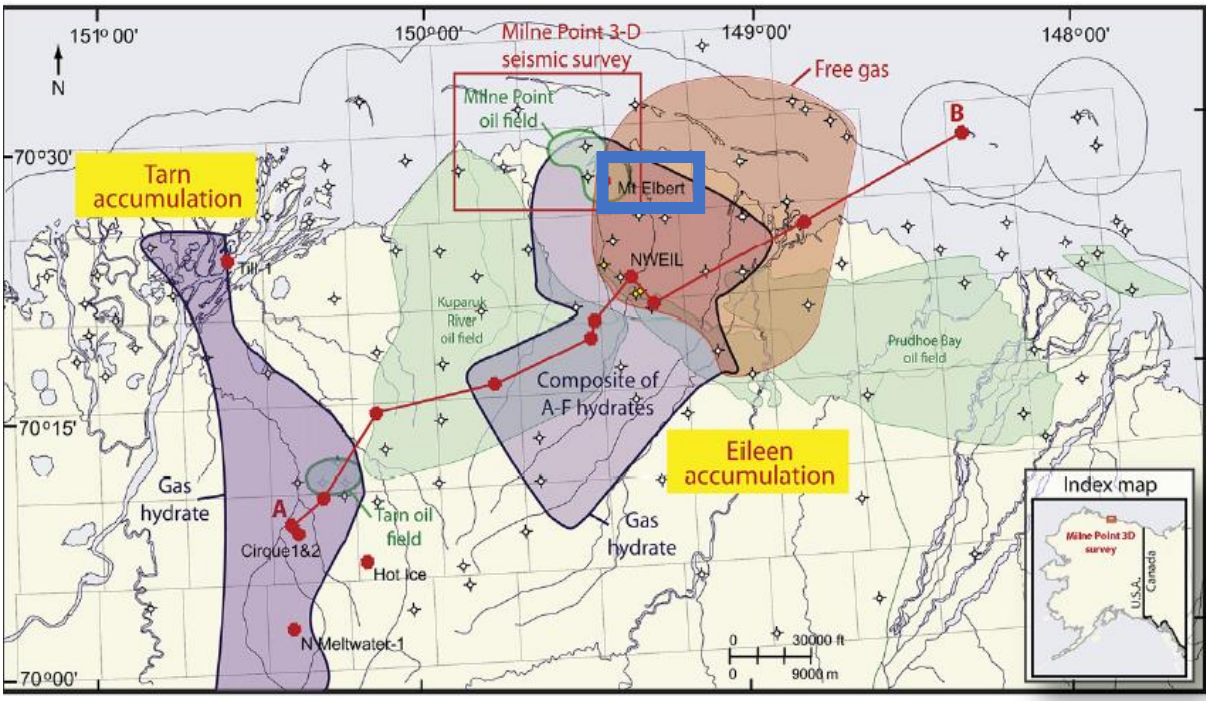

Figure 34 Map of the Eileen and Tarn gas hydrate accumulations and Mount Elbert gas hydrate research well (T. Collett 1992)

The Mount Elbert project acquired a comprehensive set of advanced well surveys, more than 130 m of the core, and MDT (Modular Formation Dynamic Tester) style formation test data. (Hunter 2004) Building on laboratory studies dealing with CH_4 hydrate CO_2 exchange technology, ConocoPhillips and the DOE entered into a cooperative research agreement in 2008 with the goal to develop a multi-year field trial to investigate CO_2 injectivity and the exchange potential of CO_2 with CH_4 in a hydrate-bearing reservoir on the ANS (D. F. Schoderbek 2013). For the investigation of the injection of CO_2 Ignik Sikumi Test Well was used, in the site where downhole log from other wells was available. From the logs, it was indicated that Eileen gas hydrate accumulation was extended in the area where Ignik Sikumi well was drilled.

6.3.1. Discussion of drilling parameters of Mount Elbert and Ignik Sikumi wells

Mount Elbert Test Well was drilled in 2008, in the permafrost region which is 594 m thick. The well was drilled for exploration purposes. The lithology of this region consisted of alternating gravel, sand and clay layers. The target zones were mainly highly saturated sand layers with gas hydrates in the depths of 614–628m and 649–666m. (Ş. Merey, Evaluation of drilling parameters in gas hydrate exploration wells 2019) From the Caliper log it can be seen that well diameter is increasing in the zone from 0 m until 600 m. The reason for this could be because the temperature of water-based drilling mud was not close to the temperature of permafrost sediments and it caused melting of ice. Observing rate of penetration, average ROP until the depth of 600 m was approximately around 25 m/h, while below 600 m increases to 50 m/hr. Below the depth of 594 m, oil-based drilling mud was used in order to avoid hydrate formation inside the wellbore. ROP has decreased again because the saturation of the hydrate section was near 80%, after which with a decrease of saturation, ROP has again reached a high value.

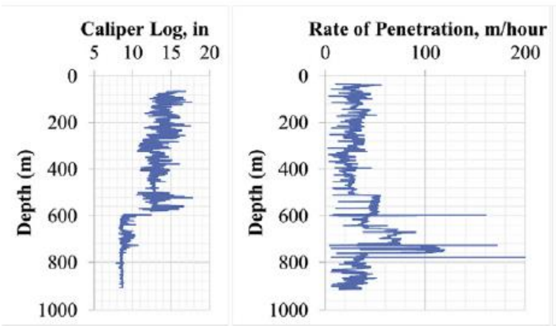

Figure 35 Drilling and log data of Mount Elbert #1 (Ş. Merey, Evaluation of drilling parameters in gas hydrate exploration wells 2019)

Ignik Sikumi Test Well was drilled in order to be used for production purposes. The aim was to apply the production test for the CH_4-CO_2/N_2 replacement method. The thickness of the permafrost was more than 250 m. Lithology consisted of sand and alternating clay layers. The depth of the gas hydrate interval was from 525 m to 740 m. From the caliper log, it can be seen that there are no important changes in the wellbore diameter, and that means that the temperature of drilling mud was close to the temperature of hydrate formation, and oil-base mud was used in order to avoid hydrate formation inside the wellbore.

Average ROP until 500 m is approximately 30 m/hr, after which it increases and reaches a value of 80 m/hr, and after reaching hydrate formation it decreases again. As can be seen, the saturation of hydrates below 600m was around 80%. A variation of saturation is because there is a layer of clay between the sand formations.

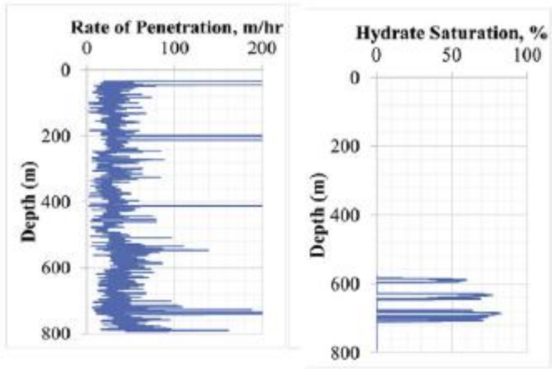

Figure 36 Drilling and log data of Ignik Sikumi #1 (Ş. Merey, Evaluation of drilling parameters in gas hydrate exploration wells 2019)

6.3.2. Production

The aim of the study conducted on the North Slope of Alaska was to evaluate CO_2/CH_4 exchange. Methane production methodology is observed during the exchange of CO_2 with CH_4 molecules in situ, while methane was released for production. After that, production with depressurization was applied. The production testing started in January 2012. Nitrogen injection, and a combination of N_2 and CO_2 into the methane hydrate reservoir was planned. For the testing purposes, the Ignik Sikumi Test Well was used, whose depth was 792 m. CO_2-N_2 mixture was injected during a period of 13 days. Injection of mixed CO_2/N_2 gas at Ignik Sikumi #1 was completed on February 28. Upon completion of the injection, the well was shut-in and surface equipment was re-configured for flow back and drawdown testing.

Production proceeded in these phases:

- jet pumping above methane hydrate-stability pressure,
- jet pumping near methane hydrate-stability pressure,
- jet pumping below methane hydrate-stability pressure.

Jet pumping is a tried and tested technology that is utilized in many well configurations to create artificial lift, which raises liquids from low-pressure conditions in reservoirs or formations. The principals engaged are simple and related to the Venturi effect. With this principle, system fluid pressure is converted into a jet stream of high energy. This creates a low-pressure condition at the pump intake.

After injecting the mixture, the well produced for 37 days, where gas production rates were exceeding 175,000 ft^3/day (4,955 m^3/day). One of the most notable scientific accomplishments of the trial was the identification of a specific mixture of N_2/CO_2 gas that prevented the formation of secondary CO_2 hydrate in the reservoir, which in turn allowed for the injection of CO_2 into the reservoir being tested.

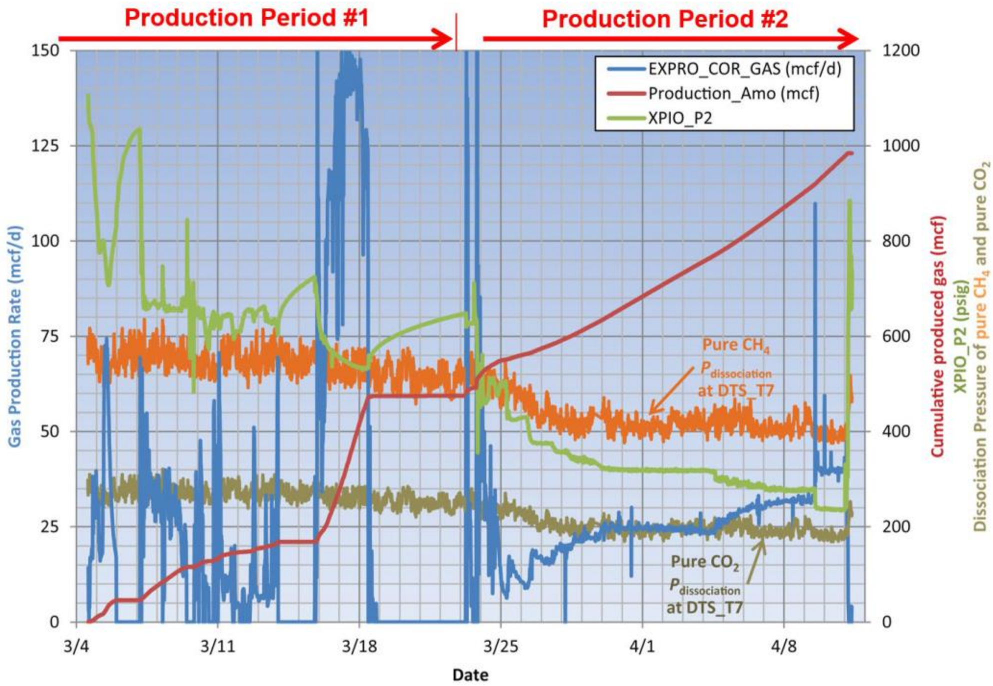

Figure 37 Results of the Iġnik Sikumi field production test (T. S. Collett 2019)

In the Figure 37, wellbore pressure can be observed, which is presented with the green line. The production gas rate is represented with the blue line, while the red line represents cumulative gas production. Two production periods can be observed from this figure. During the first period, wellbore pressure is above calculated pressure-temperature phase boundary for pure CH_4 hydrate which is shown with the orange line. While in the second period wellbore pressure is below this boundary, but it is still above the calculated pressure-temperature phase boundary for pure CO_2 hydrate presented with the dark green line.

The Iġnik Sikumi test successfully demonstrated that CO_2 could be injected into a water-bearing reservoir under conditions that would usually form secondary CO_2 hydrates, CH_4 was then produced from the reservoir, and N_2/CO_2 exchange technology was shown to be technically feasible. (D. F. Schoderbek 2013)

According to the ConocoPhillips Gas Hydrate Production Test Final Technical Report, approximately 70% of injected nitrogen and 40% of the injected carbon dioxide was recovered during the production period. A total amount of 24,211,000 cubic meters of methane was produced over the total production period.

A CO_2 /N_2 mixture was injected into a hydrate-bearing zone where water was present, and interaction between these gases and methane occurred. In order to achieve effective production of gas, the conditions inside the wellbore must be observed and controlled, such as temperature, presence of solids and the level of water.

6.3.3. Modeling gas production from hydrates

Garapati et all. 2013 developed a model for carbon dioxide and nitrogen injection into a methane gas hydrate reservoir. (Nagasree Garapati 2013) For simulating gas hydrate behavior HydrateResSim (HRS) was used. For the purposes of this research, the code has been modified in order to be applicable to the gas mixtures. By modifying HydrateResSim, the new software was developed and it is called Mix3HydrateResSim. The difference between these two is that the new software has the ability to model a mixture consisting of methane, carbon dioxide, and nitrogen. History matching was conducted for the Ignik Sakumi Test Well, where an exchange of methane with molecules of carbon dioxide was done.

The results of this study indicated that during production using gas exchange by huff and puff method (Cyclic process in which a well is injected with a recovery enhancement fluid and, after a soak period, the well is put back on production) a significant amount of water was produced, while the produced gas comes from the hydrates created and dissociated in the wellbore. Therefore, it recommends using injection and production simultaneously.

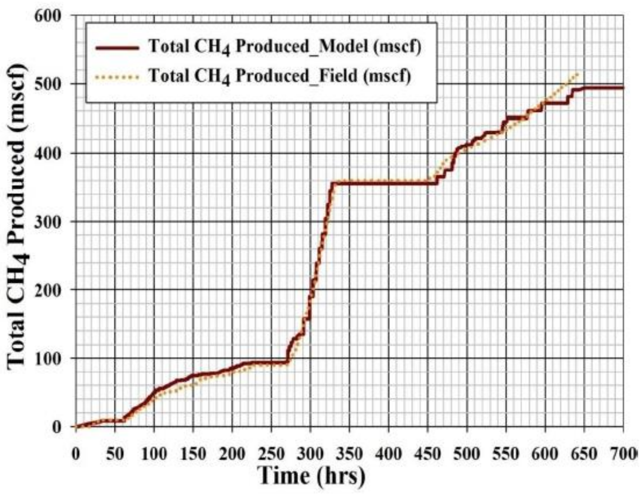

Figure 38 Cumulative volumes of CH4 gas during the production period (Nagasree Garapati 2013)

6.3.4. Conclusion

Two sites were investigated on the Alaska North Slope. The Mount Elbert site was first gas-hydrate prospect in this area, and it is investigated using seismic analysis and geophysical data, while the Ignik Sikumi gas hydrate site was used for production. Method used in Ignik Sikumi is unique and represent the new method of production which can achieve good results in similar reservoirs. Injection of CO_2 was used, but in combination with N_2, and N_2/CO_2 exchange technology was shown to be technically feasible. In order to increase the effectiveness of CO_2 injection and to avoid the CO_2 injection problem at high pressures, 77 % N_2 and 23 % CO_2 mixture injection Afterwards, depressurization was used. Benefits of this method are also that CO_2 usage as medium for recovery could be stored in the reservoir, which is contributing to environmental sustainability.

7. OFFSHORE GAS HYDRATES

7.1. Nankai Trough

Eastern Nankai Trough is located beneath the Pacific Ocean off the southeast coast of Japan. Bottom-simulating reflectors in the Nankai and in other offshore areas began to be reported after 1982. (F. S. Colwell 2004) The first attempt of production project in this area was developed in 2013, after which the second one was conducted in 2017, using two wells and applying depressurization. This area is important for investigating seismicity consistent with the tectonic movement. Beside this, it became also famous for the geological investigations of gas hydrates. Nankai Trough itself contains around 0.42 to 4.2*1012 m^3 of methane within hydrated sediments, as it is estimated by Krason.

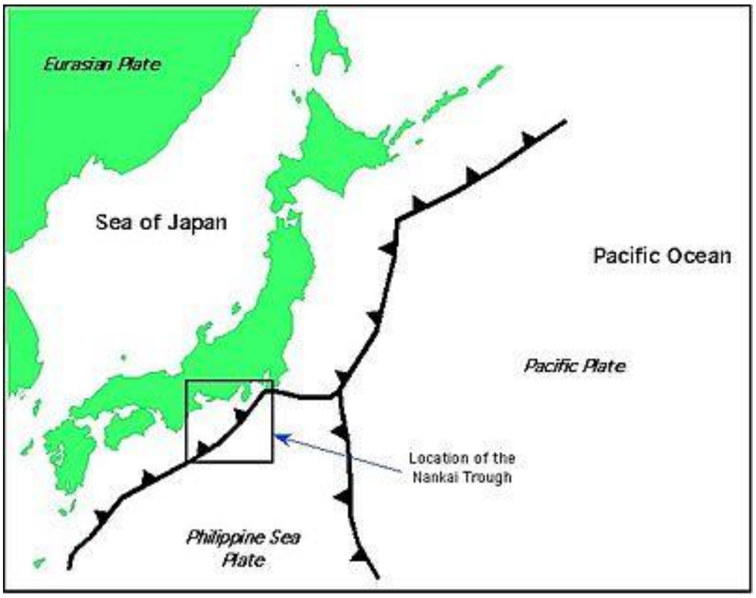

Figure 39 Location of Nankai Trough (Nankai Trough 2009)

Bottom simulating reflectors (BSRs), indicate free gas which often lies above hydrate-bearing strata, throughout the Nankai Trough. Slope sediments are mainly composed of fine-grained materials with low reflectivity. (F. S. Colwell 2004)

In the 1980s, several coring operations were conducted in order to detect presence of hydrates in this area. These operations were part of Leg 87 of the Deep-sea Drilling Project. In 1990s another coring operations were conducted as a part of Leg 131 of the Ocean Drilling Program, where hydrates were detected in the cores. Coring was conducted in the site 808, seven holes were drilled, and sample of hydrate was found in one of them. After 10 years, in 2000, drilling of seven new holes as a part of Leg 190 of Ocean Drilling Program was conducted.

JNOC (Japan National Oil Corporation) initiated a Special Research Program: Methane Hydrate Research and Development Program in cooperation with 10 private companies, with a long-term vision of producing methane gas from an offshore well that tapped a methane hydrate reservoir. (Masutani 2017)

7.1.1. Production on the Daini–Atsumi Knoll

First offshore production test site on the Daini–Atsumi Knoll

Daini–Atsumi Knoll is located in the Eastern Nankai Trough, in Japan. First offshore production test site was conducted in 2012. One production and two monitoring wells were drilled. Before drilling a well, 2D and 3D seismic surveys were conducted. During 1996, 2001 and 2002, seismic data were acquired, and more than ten prospective methane hydrate zones were found. The amount of methane in hydrates there is estimated to 1.1 trilion cubic meter. Daini–Astumi Knoll was selected as the test site for the first offshore production, which was performed from 2012 to 2013. In the Figure 40 location of the test site (northern flank of the Daini Atsumi Knoll) with a bathymetry map and the extent of the methane hydrate concentration zone (indicated by the pink solid line) is shown.

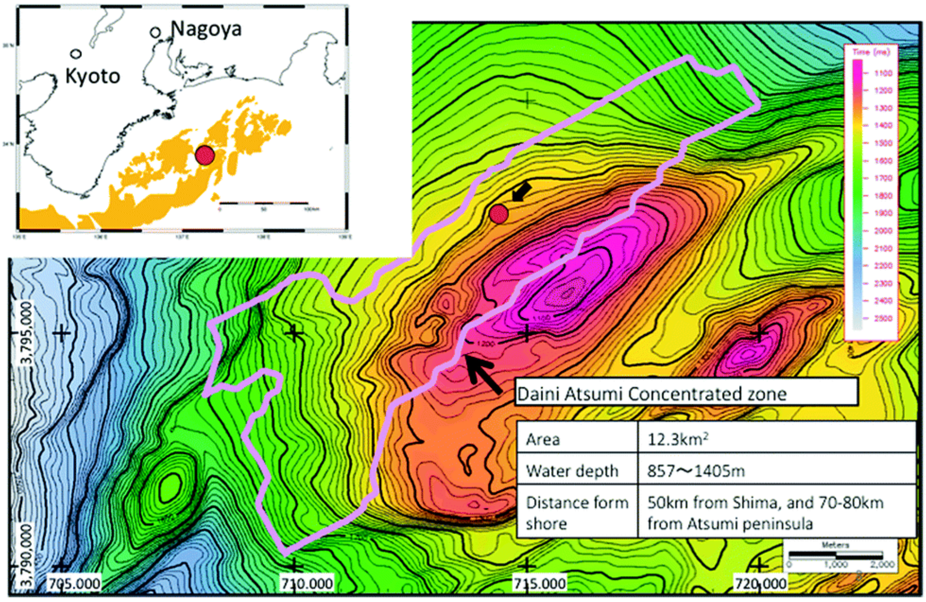

Figure 40 Area of the Daini–Astumi Knoll (K. Yamamoto 2019)

The goal of the production test conducted in Daini–Astumi Knoll was to understand dissociation of methane hydrates in in-situ conditions, and to use depressurization method in order to prove that commercial gas production can be achieved with this method from offshore methane hydrate reservoirs. As it is already mentioned, during 2012 one production well (AT1-P), two monitoring wells (AT1-MC and MT1) and one coring well (AT1-C) were drilled.

The production well was located 5-7 meters deeper than monitoring wells. The coring well was located northeast regarding the location of monitoring wells.

LWD (Logging while drilling) and WL (Wireline-logging) were conducted in monitoring well AT1-MC in order to estimate properties of reservoir. Coring was also conducted, and results were compared with results from geophysical logging data. In AT1-MC well, obtained resistivity was 1.5Ωm, and it was increased above 100Ωm in the methane hydrate concentrated zone, and these results were confirmed with logging. Lithology confirmed that methane hydrate zone has 60 m of gross thickness and a net thickness of approximately 40 m, while the silt-dominant formation just above the methane hydrate zone was more than 20-m thick; this is expected to be a seal formation. (K. Yamamoto 2019)

According to Suzuki et al., 2015 the total porosity is 40%–50% and it is calculated from density log. Saturation of hydrate in the upper sandy layer was 50%–80%, while in muddy layers located between sand layers was 0%–10%. (K. Yamamoto 2019)

Depressurization operation and gas/water production

This was the worlds' first attempt to produce gas from offshore hydrate reservoirs in early 2013 in the Daini Atsumi Knoll. The test concluded with 119 000 m3 (under ambient conditions) of methane gas production during six days of depressurization operation through a borehole drilled at 1000 m water depth. (K. Yamamoto 2019)

In order to perform production test, the hole was drilled. Sand-control devices were installed. Equipment which was used for production was set in the hole, including ESP (Electrical submersible pump), gas-liquid separator, and sensors for pressure and temperature. ESP pump was used for production, while the gas and water were already separated via downhole gas-liquid separators, reaching the surface with a different flow line.

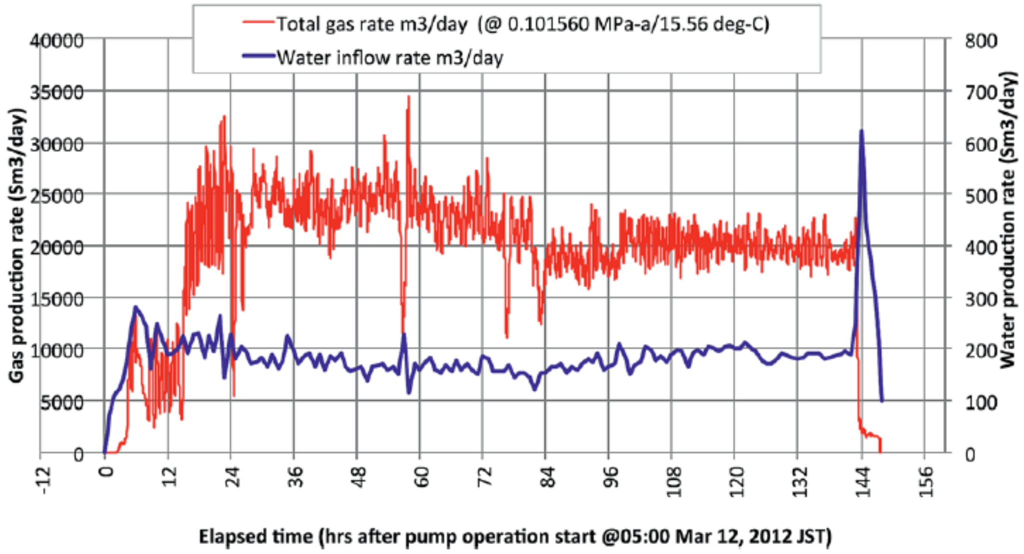

Figure 41 Gas and water rate during production test (K. Yamamoto 2019)

During the time of production, which can be seen from the Figure 41, flow rates were pretty much stable, gas rate was 20000 m3/day, while water rate was 200m3/day. It was not possible to maintain depressurization while ESP was still operating, due to the high production with the pump, which was leading to high water influx from the reservoir. And that was the reason to quit operation. In order to stabilize well, seawater was injected and pressure was returned to initial state. Therefore, plug and abandonment operation was conducted.

The second offshore production of methane hydrate in the Nankai Trough

In April of 2017, a second offshore production of methane hydrate in the Daini–Atsumi Knoll was conducted. Location of the wells were near the first production site, and two wells for producing and two for monitoring (AT1-P2, AT1-P3, AT1-MT2, and AT1-MT3) were used. Production method was depressurization. Hydrate layer, thick 70-80 m, was located 300m below the seafloor. In Figure 42 wellhead locations of 2013 and 2017 production test boreholes are shown. The deviated well paths of the wells drilled in 2013 are shown as black lines, however, the 2017 holes were drilled almost vertically using rotary steerable tools. (K. Yamamoto 2019)

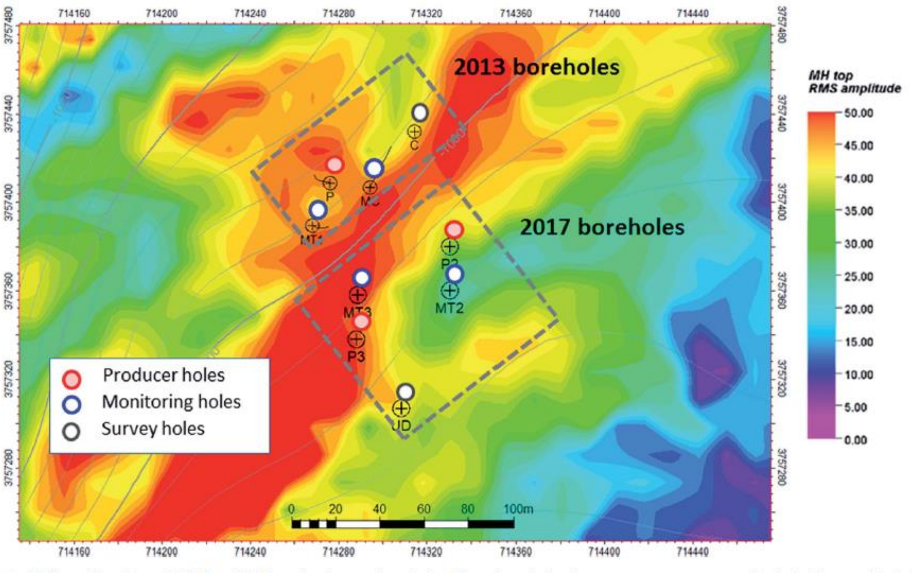

Figure 42 Location of wells used for production in 2013. And 2017. (K. Yamamoto 2019)

Formation tops in the boreholes were a couple of meters shallower in comparison with test in 2013. In monitoring wells (AT1-MT2 and AT1-MT3) pressure and temperature sensors were set. Producer wells were AT1-P2 and AT1-P3, and their location were determined so that the influence between them would be minimized. LWD was used in order to collect the data from the wells. The operation in the first borehole (AT1-P3) continued for 12 days with a stable drawdown of around 7.5 MPa and 41 000 m^3 of methane gas being produced despite intermittent sand-production events. The operation of the other borehole (AT1-P2) followed, with a total of 24 days of flow and 222 500 m^3 of methane gas being produced without sand problems. (K. Yamamoto 2019)

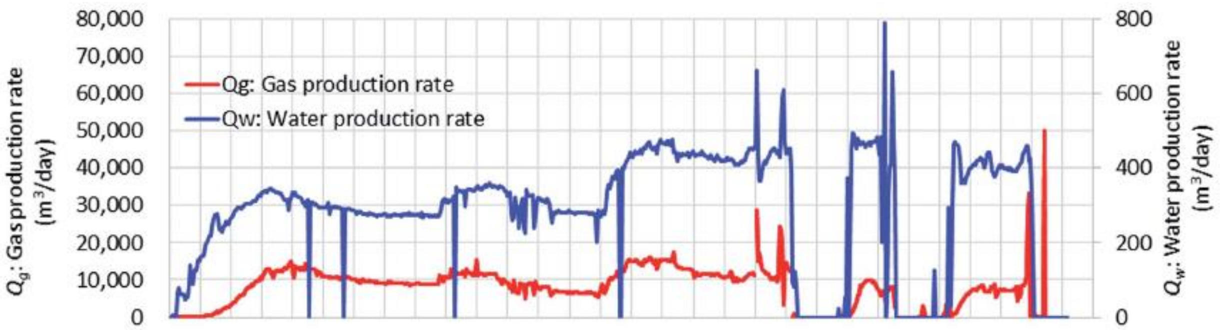

Figure 43 Gas and water production rates during production test (K. Yamamoto 2019)

7.1.2. Numerical Study on Eastern Nankai Trough gas Hydrate Production Test

Mingliang et al. (Mingliang Zhou 2014) conducted study to simulate 50 days of production on Eastern Nankai Trough. In this study methane hydrate model developed in Cambridge was used as a basis. Numerical simulator used was CMHGS (Cambridge Methane Hydrate Geomechanics Simulator).

Input parameters needed for simulations were methane hydrate critical state (MHCS) in order to describe mechanical behavior of hydrate and sediments. The tests were conducted for the different depths and later compared with actual production data in order to verify the model.

To make model simpler, an assumption that hydrates exists only in sand rich layer was taken into consideration. Method used for dissociation of hydrates was depressurization. Different scenarios were used, listed below (Figure 44):

- Scenario A: First five days pressure was reduced linearly and the rest 45 days was kept constant.
- Scenario Bi: First three days pressure was reduced linearly to 7MPa, then wait for one day, then reduction of pressure to 5MPa for one day, again waiting one day, then reduction of pressure to 3MPa, and finally pressure is kept constant until 50th day.
- Scenario Bii: First three days pressure was reduced linearly to 7MPa, then 10 days of waiting, then reducing pressure to 5MPa, wait again 10 days, then reduction of pressure to 3MPa, and finally pressure is kept constant until 50th day.

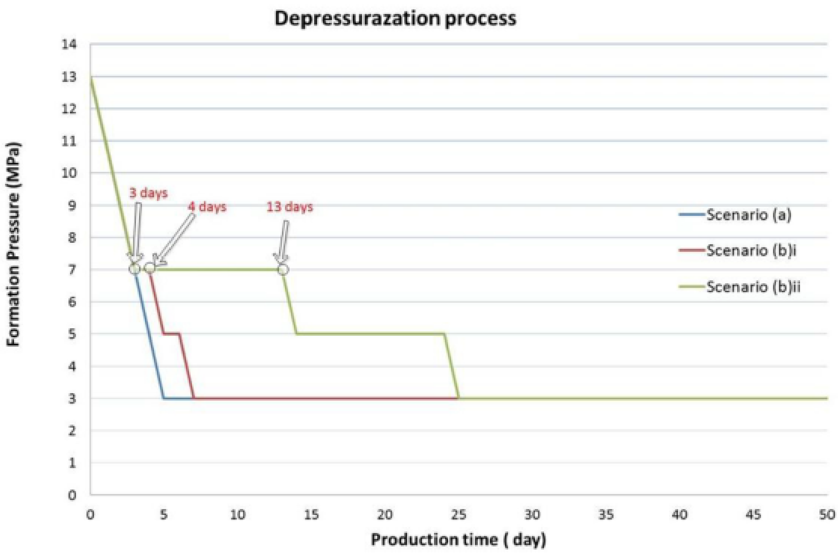

Figure 44 Depressurization in different scenarios (Mingliang Zhou 2014)

In Figure 45Figure 44 production of gas and water using different scenarios of depressurization is presented, where the same scenarios are applied in both axisymmetric and plane strain model. Axisymmetric model produces more gas than the plane strain model which is due to the volumetric effect of the axisymmetric model. Whereas the plane-strain model only has unit width, hence the production amount is limited. (Mingliang Zhou 2014) Same could be concluded observing water production.

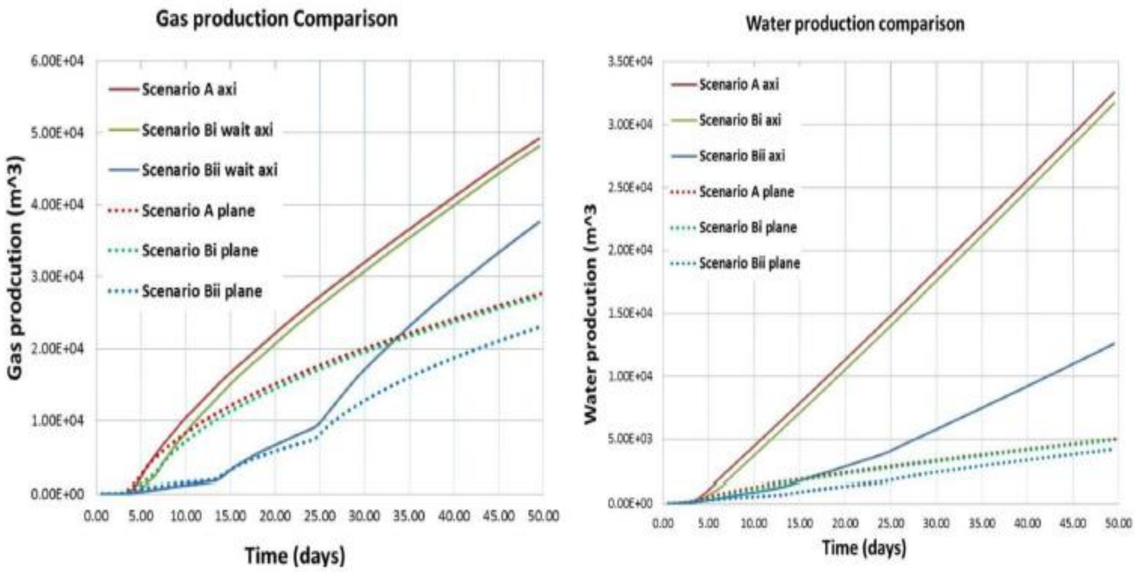

Figure 45 Gas production and water production comparison *(Mingliang Zhou 2014)*

If these scenarios of depressurization are compared, it can be said that that less of gas and water was produced using scenario Bii. This could happen due to the delayed depressurization, where 10 days was waiting period during this process. Also, it could be noted that production of gas will be similar using any scenario.

Figure 46 illustrates the two model geometries considered in this simulation: the axisymmetric case (left) and the plane-strain case (right). The seabed was assumed to be 1000m below the surface. These geometric models consider a typical condition found in Eastern Nankai Trough, Japan. In order to take inclination of the subsea ground surface into account, the plane-strain case was conducted with 10 degrees of inclination. Both geometries were simulated to simplify the real site three-dimensional problem to 2D models.

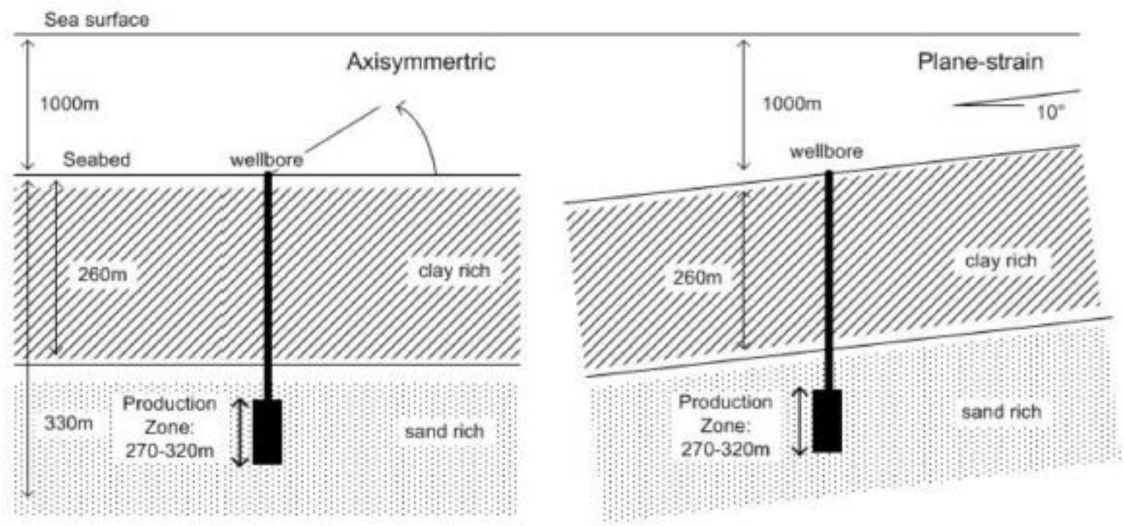

Figure 46 Numerical simulation model geometry (Mingliang Zhou 2014)

7.1.3. Conclusion

In Nankai Trough two offshore production tests were applied in Daini–Atsumi Knoll area. Method used for production in both cases was depressurization. The aim of this study was to prove that production from offshore gas hydrates is commercial using this method for production. Gas rate was 20000 m^3/day during first production test, which lasted 6 days. Problem was increased water influx and production were stopped. During second production test total gas produced from one borehole was 41 000 m^3 during period of 12 days, and from the second borehole 222 500 m^3 during 24 days. Possible solution in order to stop fast increasing water rate is to limit production, since ESP was used and this parameter can be controlled.

8. CONCLUSION

The aim of this master thesis was to make an overview of gas hydrates and gas hydrate reservoirs. In order to do it, real gas hydrate fields with available and real production data were used as an example, where different production methods were applied and several simulation studies were conducted. Focus was on fields located in permafrost, such as Mallik (Canada), Messoyakha (Russia) and Alaska North Slope (USA). Also, Nankai Trough (Japan) was presented as an example of offshore production of gas hydrates.

Depressurization, as a production method, was used in most of them, thermal stimulation was applied in Mallik, while in Alaska North Slope and Messoyakha depressurization was used in combination with inhibitor injection. It can be concluded that depressurization can give good results, especially if additional method such inhibitor injection is also applied. Problems such as re-formation of hydrate near wellbore during production can be solved using inhibitors. Certainly, this will increase the cost of production itself. Possibility for producing gas from gas hydrate reservoirs in permafrost is higher than offshore, due to the fact that offshore reservoirs are located deeper, but methods developed producing from permafrost zones should be also considered to be applied for offshore reservoirs.

There are many examples of a possible gas hydrate reservoirs in the world, nevertheless production tests were not applied in many of them due to the feasibility and cost-effectiveness of the final results. Even though this type of reservoirs are estimates as a possible source of energy, currently gas production from gas hydrate reservoirs does not contribute to global gas production from conventional sources. Certainly, this energy source should not be neglected in the future, production from conventional reservoirs will not always be the best option and developing new production methods which will be more profitable is always possible.

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