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Economic Analysis of a Marine Gas Hydrate Operation from the sea floor and its sediments

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Economic Analysis of a Marine Gas Hydrate Operation from the sea floor and its sediments
The Case of Hydrate Bearing Sediments in the Atwater Valley

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Executive Summary

Natural gas is an important energy source. Recently the world-wide consumption is rapidly increasing due to the growing demand caused by industrial growth and also by shifting to cleaner energy source driven environmental concerns. To satisfy demand also in the future, it is necessary to look for alternatives sources of supply of energy.

An alternative could be the gas production from Natural Gas Hydrates (NGH), which are ice-like crystalline compounds that form from water and gas at low temperature and high pressure. NGH are found in subsurface either near the surface in arctic regions or in deep water marine environments. The estimated volume of NGH with respect to energy contains twice the amount of currently recoverable world-wide fossil fuels. IHC Merwede (IHC) is interested in the potential of deep sea mining of NGH.

This defines the research question: ***"Is deep sea mining of gas hydrates from the sea floor and sediments feasible from a technological and economic perspective?"***

An extensive review of literature on NGH-deposits shows that they exist globally but occur predominantly around the edge of the continents in marginal marine basins and some in permafrost regions. The occurrence of hydrates depends on the temperature, pressure and the kind of gas. Depressurization, thermal- and chemical stimulation are three possible dissociation mechanisms for the production of hydrocarbon gases from NGH.

For further research the Atwater Valley in the Gulf of Mexico was chosen based on the high potential and available information about this site. This research was necessary to verify the technological and economic perspective of mining marine natural gas hydrates.

The main conclusions concerning the ***technological*** *perspective were identified:*

Deep sea mining of gas hydrate bearing sediments (GHBS) is possible from a technological point of view. However, for a reliable feasibility study on potential mining operations of GHBS more research into geological data needs to be done. Nevertheless, this study shows that existing know-how and equipment for deep-sea mining could be used to excavate GHBS. Thereby, future investigations should focus on the intermediate transport of the excavated sediment to a separation unit. Even though several technologies are available to remove liquids and solids from gases there are no operational plants to process GHBS. Compressed Natural Gas seems to be the best way to transport the gas from the mining site to its market.

The main conclusions concerning the ***economic*** *perspective were identified as:*

The project's economic viability of the base case is negative. A sensitivity analysis (a relative change of +/- 30% on the input variables) shows that the economic viability remains always negative. This is mainly caused by the high operating- and capital expenditures. Especially the CAPEX on the initial phase of the operation is high. The revenues are not high enough to offset these expenses.

To make the mining economically attractive, the required gas price has to be almost ten times the current gas price of 4.2 US$/mmBtu.

Nevertheless this thesis provides insight into the various aspects of the recovery of natural gas from GHBS operated from a vessel. Based on the conclusions of this research it is ***recommended*** *to:*

Do detailed research into: geotechnical properties of GHBS such as compressive-, tensile- and cohesive strength; the behaviour of NGH during extraction and vertical transportation; the environmental impact of physical mining of marine gas hydrates; the processing of GHBS; the producable reserves from NGH-deposits; and technological innovations to lower OPEX and CAPEX.

The developed cash flow model for NGH-operations allows evaluating the financial parameters. Further research and development is recommended to optimise the model for other deep sea mining operations.

Preface

This report is the result of my thesis project for the Master of Science degree of Resource Engineering, at Delft University of Technology. The project was carried out at MTI Holland B.V., the Research and Development section of IHC Merwede B.V.

First of all I would like to thank Henk van Muijen for giving me the opportunity to do my thesis at MTI Holland B.V. Additionaly, within MTI, I would like to thank Paul Vercruijsse and Jan Willem van Bloois for sharing their knowledge and expertise with me.

At Delft University of Technology I would like to thank Hans de Ruiter for being chairman of the committee, for his enthusiasm and support during my mining engineering study. Susanne Rudolph (Petroleum Engineering) is acknowledged for her interest, knowledge and cooperative approach to this gas hydrate related project.

I also would like to thank everyone who helped me in the final phase on this project for their "helicopter view" and for reading and commenting my report. Last, but not least, I would like to thank my family for their support throughout my studies and in life.

Romboud Harskamp

May 20th, 2010

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List of Abbreviations

AV	Atwater Valley
BSR	Bottom Simulating Reflectors
CAPEX	Capital Expenditures
CNG	Compressed Natural Gas
CO_2	Carbon dioxide
EEZ	Economic Exclusive Zone
EIS	Environmental Impact Statements
EPA	Environmental Protection Agency
FPSO	Floating, Production, Storage and Offloading Vessel
GH	Gas Hydrate(s)
GHBS	Gas Hydrate Bearing Sediment(s)
GHSZ	Gas Hydrate Stability Zone
GOM	Gulf of Mexico
GtC	Gas to Commodity
GtL	Gas to Liquids
GtW	Gas to Wire
HRT	Hydrate Recovery Tool
IRR	Internal Rate of Return
ISA	International Seabed Authority
kg	kilogram
kPa	kilo pascal
lb	Pound
LNG	Liquified Natural Gas
m	metre
mbsf	Metres below sea floor
(mm)Btu	(million) British thermal unit (1 mmBtu = 28.26 m^3)
(mm)scf	(million) standard cubic feet
MMS	Minerals Management Service
MSV	Mining Support Vessel
NGH	Natural Gas Hydrate(s)
NOAA	National Oceanic and Atmospheric Administration
NPDES	National Pollutant Discharge Elimination System
NPV	Net Present Value
OCS	Outer Continental Shelf
OPEX	Operational Expenditures
PNG	Pipeline Natural Gas
ppt	parts per thousand
STP [a]	Standard Conditon for Temperature (20 °C) and Pressure (100 kPa ≈ 1 bar)
USGS	United States Geological Survey
VRM	Vertical Riser Mechanism

[a] According to United States Environmental Protection Agency (EPA)

1. Introduction

Natural Gas Hydrates (NGH) are crystalline solids composed of water and gas, in which the 'guest' gas molecules are trapped in water cavities(host) surrounded by hydrogen-bonded water molecules (Sloan, et al., 2008). NGH can be formed when a guest molecule is combined with water at low temperatures and high pressures.
Of particular industrial interest are the gas hydrates, hydrocarbon gases. These NGH-deposits can be found in two different settings in which the thermodynamic conditions are suitable for their existence: onshore in permafrost regions and offshore in marine sediments. The estimated volume of NGH with respect to the energy contains twice the amount of currently recoverable world-wide fossil fuels (Sloan, et al., 2008). Some of these hydrates are situated at or near the sea floor in gas hydrate bearing sediments.
Due to the considerable size of this potential resource, even if only a fraction of the natural gas in hydrates can be proven technically and economically recoverable, the production of NGHs could become a part of the world's energy portfolio as a supply of natural gas to global markets.

1.1. Thesis scope

IHC Merwede (IHC) is interested in the technology to extract and transport natural gas hydrates for commercial purposes. IHC have gained significant experience in dredging and near shore marine mining over the years. At the moment IHC is busy to expand this experience towards the extraction of minerals from other deposits, such as natural gas hydrate deposits. There are differences between NGH-deposits and its dredging operations versus near shore mining operations. These are:

- Dimensions and geotechnical properties of the resource
- Sensitivity to hyperbaric effects (which can be attributed to greater water depth and/or overburden)
- Environmental conditions; and
- Distance to shore

1.1.1. Thesis Goal and Objectives

The goal of this thesis is to make a contribution to the knowledge and understanding of presence of natural gas hydrate deposits and the requirements for successful extraction of deposits.

The main research question is:

"Is deep sea mining of gas hydrates from the sea floor and sediments feasible from a technological and economic perspective?"

To answer this question the following thesis objectives are to be defined:

- Summarize the knowledge of natural gas hydrates and the potential with respect to the recovery and supply to the market place.
- Gain better understanding of extraction, transportation and processing that are suitable for gas hydrate deposits.

To reach these objectives the following specified tasks were set:
- Research what kind of marine Natural Gas Hydrate deposits exist globally.
- Analyse the conditions and properties of these deposits focusing on:
    - Types of Natural Gas Hydrates
        - Structures
        - Geography
        - Classification
    - Location of hydrates
    - Extension of resources
    - Geotechnical properties
    - Environmental conditions
    - Types of commodities that occur in these deposits and their values

Several NGH-deposits seem to be very promising resources in the supply of natural gas. Based on preliminary qualitative analysis of three different seabed gas hydrate deposits it was decided to do a more in-depth investigation into one of these deposits.
From a mining technology perspective the following topics were investigated using a standard mine planning process as a guideline:
- Identify constraints for successful NGH extraction, processing, transportation and markets.
- Determine the feasibility to extract these gas hydrate bearing sediments.
- Analyse and define the economic potential for extraction for one specific deposit:
    - Breakage technology / extraction method respecting the environment and properties.
    - Feasible method of vertical transportation from the seabed deposit to the surface support vessel.
    - An overview of suitable techniques for further processing and transportation.
    - Economic analysis to assess the economic viability
- Propose further avenues of research and/or investigation.

1.2. Method of Approach

The basics of an extensive literature review on geology of Natural Gas Hydrate deposits provided insight in their properties and conditions.

Secondly a pre-feasibility study was developed for a specific NGH-deposit in the Atwater Valley, Gulf of Mexico. The requirements to extract the Gas Hydrate Bearing Sediments were based on additional literature reviews, different types of communication (interviews, brainstorm session and e-mails) with supervisors and experts. Additionally, a base case scenario model was created. The focus of this pre-feasibility study is on an analysis to assess the economic viability.

1.2.1. Prefeasibility Study Layout

The concept study is usually the start of a mining operation, which goes through several phases, after initial exploration has deemed a deposit as a promising resource (Figure 1-1). In appendix A another way of looking at Mine Planning process steps is presented (according Slagmolen, 2009). That presentation of the process highlights the iterative characteristics which mean that results obtained at an earlier stage sometimes have to be altered due to constraints at a later stage. This way a system can be optimised.

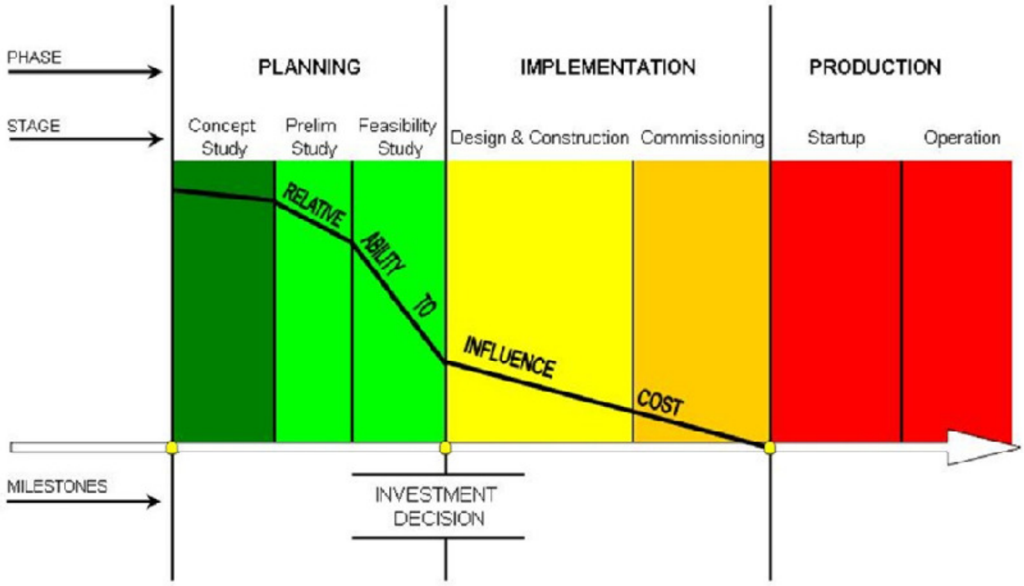


Figure 1-1 Mine planning process (modified from Hustrulid and Kuchta (2006))

The following description of a preliminary or pre-feasibility study is from Hustrulid and Kuchta (2006).

A preliminary study is an intermediate-level exercise, normally not suitable for an investment decision. It has the objectives of determining whether the project concept justifies a detailed analysis by a feasibility study, and whether any aspects of the project are critical to its viability and necessitate in-depth investigation. A preliminary study should be viewed as an intermediate stage between a relatively inexpensive conceptual study and a relatively expensive feasibility study. Some studies are done by a two or three-man teams that have access to consultants in various fields others may be multi-group efforts.

The preliminary study is based on critical sections like (Hustrulid, et al., 2006):

- Aim
- Technical concept
- Findings
- Ore quantity and grade
- Mining and production schedule
- Capital cost estimate
- Operating cost estimate
- Revenue estimate
- Taxes and financing
- Cash flow tables

The degree of detail depends on the quality of information.

2. Marine Natural Gas Hydrate deposits

2.1. Introduction

Natural gas hydrates (NGH) are ice crystalline compounds which are formed by association of molecules of water (host) and natural gas (guest). Typical natural gas molecules include methane, ethane, propane, and carbon dioxide.
Their formation and dissociation is described by the general equation

$$\underset{\text{(Methane)}}{G} + \underset{\text{(Water or Ice)}}{N_H H_2O} \Leftrightarrow \underset{\text{(Hydrate)}}{G * N_H H_2O} \tag{2.1}$$

Where N_H is the hydration number and G is a hydrate-forming gas. NGHs in geological systems contain $G=CH_4$ as their main gas ingredient. The hydrate formation reaction is an exothermic process which means it generates heat. The dissociation of gas hydrates is an endothermic process (like ice), which means it absorbs heat. The formation of NGH depends on pressure, temperature, gas composition and presence of inhibitors (i.e. salts). Natural Gas Hydrates are found in two distinct types of settings: permafrost in arctic regions and in deepwater marine sediments. In the past, NGH were seen as negative obstacles because of the formation of hydrates in pipelines. However researchers discovered that certain chemicals could be injected into the pipelines to prevent forming of hydrates (Makogon, 1997).

The global quantity of hydrate-bound methane is estimated to be (3-5) x 10^{15} m^3 (Milkov, 2004). The characterization of NGH-deposits involves collection and interpretation of geo-mechanical, geophysical, sedimentological and thermal data. It is important to analyse the properties of hydrate bearing sediments with respect to the gas production and geo-mechanical instabilities related to hydrates.
One cubic metre of methane hydrate can encapsulate up to 160 m^3 methane at standard temperature and pressure.

Where is Natural Gas Hydrate found?
Natural gas hydrates (NGH) occur predominantly around the edge of the continents and in marginal marine basins, like the Black Sea and Gulf of Mexico, and in some permafrost regions, as shown in the Figure 2-1. The white dots are the recovered NGH samples, while the black dots are the inferred NGH occurrence based on: bottom simulating reflection (BSR) and well logs. This map was created in 2007, but still shows the basic pattern of world-wide NGH distribution.

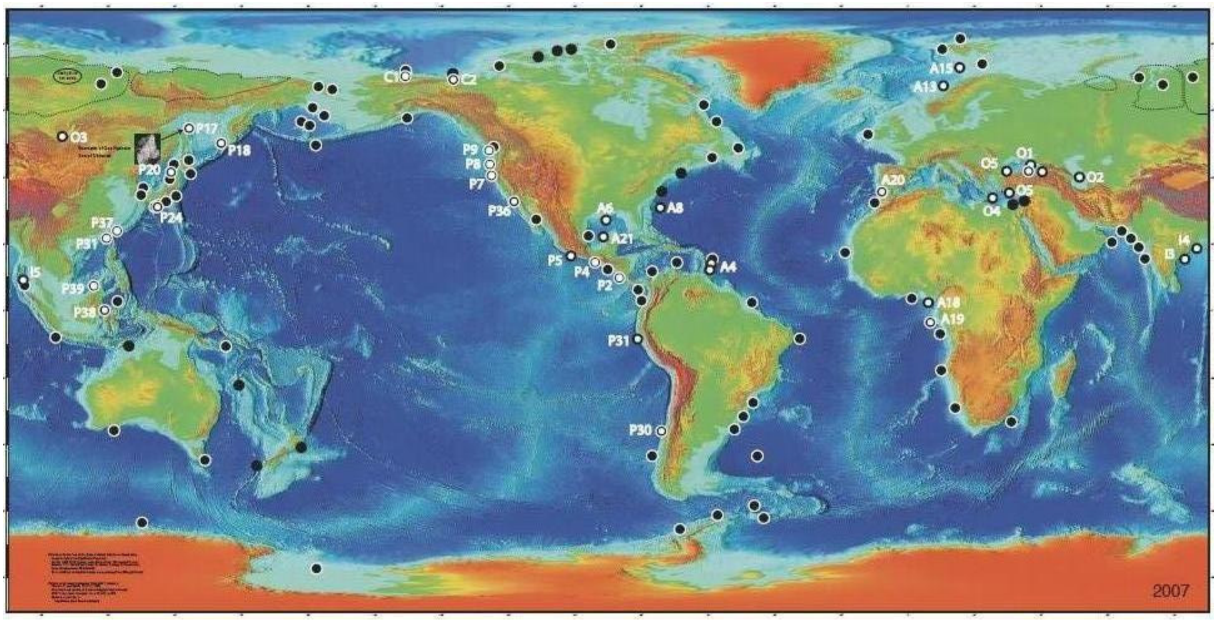


Figure 2-1 A global inventory of Natural Gas Hydrate occurrence (Kvenvolden, et al., 2008)

2.2. The division of the oceans

The division of the oceans is done on several levels: political, geological, biological, economical and several others. For this study the focus will be on the economic value of marine deposits, but it is essential to understand the political and geological division as well to make a good economic assessment of the marine deposits.

Marine sediments
Chester (2003) divided the sea floor into three major topological regions: the continental margins, the ocean-basin floor and the mid-ocean ridge system. An extensive description of the processes of these regions is not required for this project. A summary of legislative classification as well as the various supply processes of elements to the ocean floor is given in the next sub-paragraphs.

Legislation
The International Seabed Authority (ISA) is an autonomous international organisation established under the 1982 United Nations (UN) Convention on the Law of the Sea. This convention and the 1994 agreement relate to the implementation of part XI of the UN convention on the Law of the Sea. It defined the geographical borders and the rights of coastal nations to the adjacent ocean and ocean floor (ISA, 2009). The ISA is the organisation that oversees the adherence to the convention by the international community and divides the ocean into four areas Figure 2-2:

- State / Territorial Sea (within 3 nautical miles of the coast);
- Continental Shelf (up to the continental slope)
- Economic Exclusive Zone (EEZ, within 200 nautical miles of the coast);
- The International Area (the area, outside the EEZ)

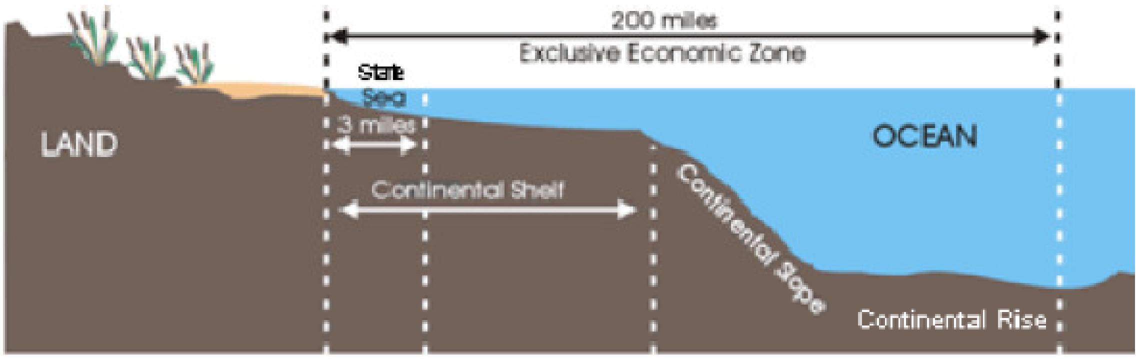


Figure 2-2 Continetnal shelf and slope (EIA, 2005)

The tendency for NGH to accumulate at continental margins means that much of it falls within the EEZ of coastal nations (shown in Figure 2-1), many of which are not presently energy producers. Thus if gas hydrate proves to be a viable energy source, its presence in the EEZ of many nations will change global energy distribution and its economics (Max, et al., 2006).

The ISA focuses strongly on the impact of deep seabed mining. It has produced several legal statements that intent to guide these activities in a safe and responsible manner. The Code for Environmental Management of Marine Mining (CEMMM) is one of these. This has been created by the International Marine Minerals Society (IMMS). The operating guidelines are proven benchmarks by which a mining company can set its environmental program for a marine exploration or extraction site.
Marine mining companies adopting this environmental code commit themselves to the following principles (IMMS, 2009):

- To observe the laws and policies and respect the aspirations of sovereign states and their regional sub-divisions, and of international law, as appropriate to underwater Mineral developments.
- To apply best practical procedures for environmental and resource protection, considering future activities and developments within the area that might be affected.
- To consider environmental implications and observe the precautionary principle from initiating a project through all stages from exploration through development and operations, including waste disposal, to eventual closure and post-closure monitoring.
- To liaise with stakeholders and facilitate community partnerships on environmental matters throughout the project's life cycle.
- To maintain an environmental quality review program and deliver on commitments.
- To report publicly on environmental performance and implementation of the Code.

Within the EEZ legislation depends on the individual countries. Exploration and mining activities can be regulated by several different sets of legislation. Another critical issue is that vessels can be sailing under the flag of a different country than the country linked to EEZ and therefore might be affected by two different sets of legislation.

2.3. Properties of Natural Gas Hydrate

2.3.1. Structures

All common NGHs belong to one of the three hydrate structures, cubic structure I (sI), cubic structure II (sII) or hexagonal structure H (sH). These crystal structures are shown in Figure 2-3.

Cubic structure I (sI) is formed with guest molecules, such as methane, ethane, carbon dioxide and hydrogen sulphide. The guest molecules have diameters between 0.4 – 0.6 nm and are predominate in the earth's natural environment. Structure II (sII) is formed with larger guest molecules with diameters between 0.6 – 0.7 nm. There are hydrated molecules (Ar, Kr, O_2 and N_2) with smaller diameters (< 0.4 nm) that form structure II as single guests. Hexagonal structure H (sH) may occur in either environments with larger molecules (0.8 – 0.9 nm), but sH gas hydrates can also form in combination with smaller molecules (i.e. methane, hydrogen sulphide, or nitrogen). For example $5^{12}6^4$ indicates a water cage composed of 12 pentagonal and four hexagonal faces. The exponents indicate the number of cage types. Structure I unit crystal is composed of two 5^{12} cages, six $5^{12}6^2$ cages and 46 water molecules. Structure II unit crystal is composed of sixteen 5^{12} cages, eight $5^{12}6^4$ cages and 136 water molecules. Structure H consists of; three 5^{12} cages, two $4^35^66^3$ cages, one $5^{12}6^8$ and 34 water molecules. The properties are tabulated in Appendix B.

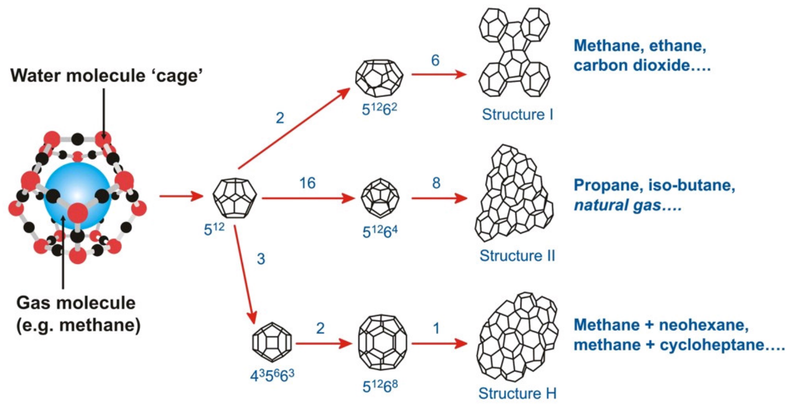


Figure 2-3 The common hydrate structures(Heriot-Watt-University, 2010)

Pure methane (CH_4) and ethane (C_2H_6) form structure I hydrates. If a hydrocarbon gas is larger than ethane (like propane, butane), structure II hydrates are formed. Structure H hydrates occur with larger gas molecules such as butane (i.e. isopentane), but they also accommodate smaller molecules (C_1-C_4).

2.3.2. Density

The density of gas hydrates can vary from 0.8 to 1.2 g/cm^3. Table 2-1 shows the densities of some pure hydrates at 0°C and standard pressure (0.1 MPa). The densities of hydrocarbon hydrates are similar to that of ice, while the densities of other hydrates are denser. E.g., the density of methane hydrates is 0.913 g/cm^3, which is less than the density of water or ice. However, there are some uncertainties about the density, because not all cavities are occupied.

Table 2-1 Densities of some hydrates at 0 °C (Carroll, 2009)

	Hydrate Type	Density [g/cm³]
Methane	I	0.913
Ethane	I	0.967
Propane	II	0.899
Isobutane	II	0.934
CO2	I	1.107
H2S	I	1.046
Ice	-	0.917
Water	-	1.000

2.3.3. Enthalpy of fusion

The 'enthalpy of fusion' or 'heat of formation' could be a useful property, because it could give information about the energy that is required to melt a hydrate. Table 2-2 shows the 'enthalpy of fusion' for different hydrates.

Table 2-2 Enthalpies of fusion for different gas hydrates (Carroll, 2009)

	Hydrate Type	Enthalpy of Fusion [kJ/g]	Enthalpy of Fusion [kJ/mol]	Enthalpy of Fusion [Btu/lb]
Methane	I	3.06	54.2	1320
Ethane	I	3.70	71.8	1590
Propane	II	6.64	129.2	2850
Isobutane	II	6.58	133.2	2830
Ice	-	0.333	6.01	143

2.3.4. Comparison of properties of hydrates and ice

Mechanical properties of hydrates are in general comparable to those of ice. In Table 2-3 a summary of microscopic and macroscopic properties for ice and hydrate structure I and II are listed.

Table 2-3 Comparison of properties of ice and hydrates (Sloan, et al., 2008)

Property	Ice	Structure I	Structure II
Structure and dynamics			
Crystallographic unit cell space group	$P6_3/mmc$	Pm3n	Fd3m
No. of H_2O molecules	4	46	136
Lattice parameters at 273 K (Å)	$a = 4.52$, $c = 7.36$	12.0	17.3
Dielectric constant at 273 K	94	~58	~58
Far infrared spectrum	Peak at 229.3 cm^{-1}	Peak at 229.3 cm^{-1}	with others
H_2O reorientation time at 273 K (μs)	21	~10	~10
H_2O diffusion jump time (μs)	2.7	>200	>200
Mechanical properties			
Isothermal Young's modulus at 268 K (10^9 Pa)	9.5	8.4^{est}	8.2^{est}
Poisson's ratio	0.3301^a	0.31403^a	0.31119^e
Bulk modulus (GPa)	8.8; 9.097^a	5.6; 8.762^a	8.482^a
Shear modulus (GPa)	3.9; 3.488^a	2.4; 3.574^a	3.6663^a
Compressional velocity, V_p (m/s)	3870.1^a	$3778^{a,b}$	3821.8^a
Shear velocity, V_S (m/s)	1949^a	1963.6	2001.14^b
Velocity ratio (comp/shear)	1.99	1.92	1.91
Thermal properties			
Linear thermal expansion at 200 K (K^{-1})	56×10^{-6}	77×10^{-6}	52×10^{-6}
Thermal conductivity ($Wm^{-1} K^{-1}$)	2.23	0.49 ± 0.02;	0.51 ± 0.02
at 263 K	2.18 ± 0.01^c	0.51 ± 0.01^c 0.587^d	0.50 ± 0.01^c
Adiabatic bulk compression at 273 K (GPa)	12	14^{est}	14^{est}
Heat capacity ($Jkg^{-1} K^{-1}$)	1700 ± 200^c	2080	2130 ± 40^c
Refractive index (632.8 nm, −3°C)	1.3082^e	1.346^e	1.350^e
Density (g/cm^3)	0.91^f	0.94 also see Example 5.2	1.291^g

* *Note:* Unless indicated, values are from Davidson (1983), Davidson et al. (1986b) and Ripmeester et al. (1994).

[a] Helgerud et al. (2002) at 253–268 K, 22.4–32.8 MPa (ice, Ih), 258–288 K, 27.6–62.1 MPa (CH_4,sI), 258–288 K, 30.5–91.6 MPa (CH_4–C_2H_6, sII).

[b] Helgerud et al. (2003) at 258–288 K, 26.6–62.1 MPa.

[c] Waite et al. (2005) at 248–268 K (ice Ih), 253–288 K (CH_4, sI), 248–265.5 K (THF, sII).

[d] Huang and Fan (2004) for CH_4, sI.

[e] Bylov and Rasmussen (1997).

[f] Fractional occupancy (calculated from a theoretical model) in small (S) and large (L) cavities: sI = CH_4: 0.87 (S) and CH_4: 0.973 (L); sII = CH_4: 0.672 (S), 0.057 (L); C_2H_6: 0.096 (L) only; C_3H_8: 0.84 (L) only.

[g] Calculated for 2,2-dimethylpentane 5(Xe,H_2S)·34H_2O (Udachin et al., 1997b); est = estimated.

2.4. Controls of hydrate stability

Pressure, temperature, gas composition and presence of inhibitors influence on the stability of natural gas hydrates. Figure 2-4 shows the equilibrium curve (in red line). The equilibrium curve shifts to the right (blue line in Figure 2-4) when heavier hydrocarbons, along with methane participate in hydrate formation. The equilibrium curve shifts to the left (green line) with increasing concentration of hydrate inhibitors (such as; salts and alcohols).

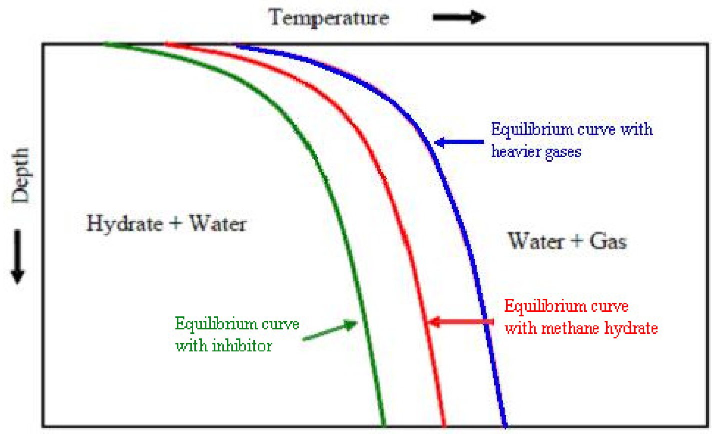


Figure 2-4 Methane hydrate equilibrium curve (modified from Grover, 2008)

2.5. Gas hydrate stability zone

Hydrates occur in two different regions: in continental polar regions and in marine sediments. In marine sediments the hydrates are found in water depths greater than 200 to 600 metres. The occurrence of hydrates depends on the temperature and pressure on the seafloor and the gas composition. Figure 2-5 illustrates typical marine hydrate deposits of depth-temperature zones in which NGH are stable. The phase boundary is actually the equilibrium curve and the arched region is the Gas Hydrate Stability Zone (GHSZ) and it means that according to the temperature –pressure window natural gas hydrate 'could' be present. If hydrates are formed in the GHSZ it will be stable in this part.

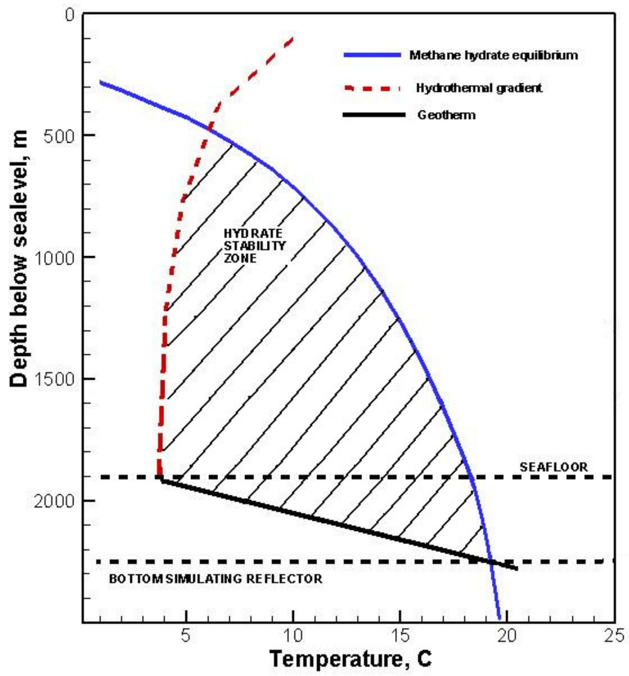


Figure 2-5 Hydrate stability zone in an Oceanic Hydrate formation (Grover, 2008)

2.6. Origin of methane in gas hydrates

Of the two sources of methane (biogenic or thermogenic) in NGH the biogenic one is the most common (Sloan, et al., 2008). *Biogenic* methane is generated by bacterial interaction with buried organic matter in an anoxic environment. The methane that is formed comes from shallow depths and travels a relatively short distance. *Thermogenic* methane is generated by cracking of high hydrocarbons at greater depths. The methane comes from either oil or natural gas deposits.

2.7. Dissociation mechanism

The transformation of solid hydrate to water and gas is referred to as 'dissociation'. This term describes the process by which a chemical combination, such as hydrate, becomes unstable and breaks up into its component constituents through the application of either pressure release or temperature increase, or both (Max, et al., 2006).

$$\text{Dissociation: Methane Hydrate} \rightarrow \text{Water}_{\text{Liquid}} + \text{Methane}_{\text{Gas}}$$

The dissociation of gas hydrate is fairly slow even during the transfer out of the gas hydrate stability zone. While hydrate formation produces heat, hydrate dissociation requires energy in order to break the crystal structure of the hydrate and release the gas. One of the reasons for this slow transformation is the endothermic process of gas hydrate dissociation. It absorbs heat when it dissociates and results in diminishment of the rate of dissociation. This phenomenon has been referred to as 'self preservation' (Max, et al., 2006).During some research projects the drilled samples of gas hydrate often survive the trip from the sea floor to the surface.

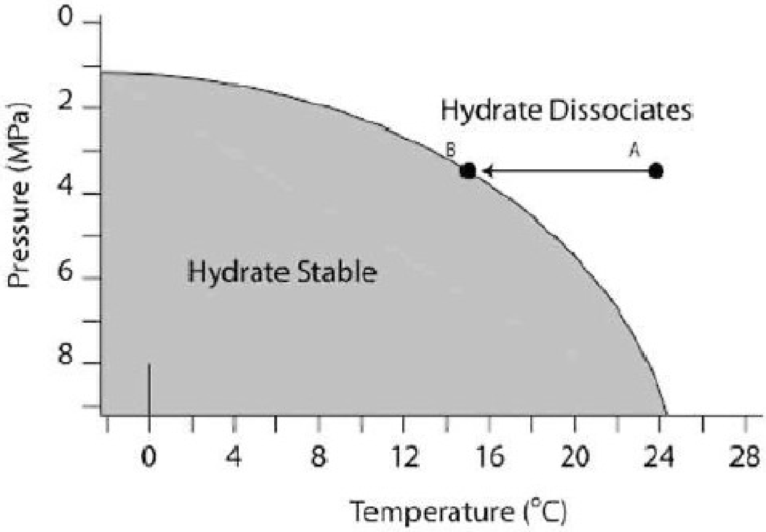


Figure 2-6 Representative diagram of the pressure-temperature stability relationship for hydrate. Point A: T-P conditions at which hydrate is not stable. Point B: Equilibrium conditions at the same pressure found at point A. (Max, et al., 2006)

Figure 2-6 shows the temperature-pressure relationship that can be used as a generalization for all hydrocarbon hydrates. The grey shaded area shows the conditions at which hydrates are stable. The region on the other side of the phase boundary (black line) represents conditions where hydrates are not stable.

There are different mechanisms for the production of methane from gas hydrates, which are:

- Depressurization
- Thermal stimulation
- Inhibitors (chemical stimulation)

Figure 2-7 shows the different mechanisms of hydrate dissociation. *Depressurization* means that methane gas is extracted by reducing the pressure inside the riser by reducing the specific gravity or amount of the drilling mud, causing the methane hydrate to decompose.
Thermal stimulation means that the gas is extracted by circulating hot water or steam down through the well to the hydrate bearing layer, causing the NGH to decompose. This method was used during the Mallik (onshore at Canada's Mackenzie Delta) production test, which resulted in the extraction of significant amounts of methane gas.
The last one is a *chemical injection* (such as salts or solvents) to shift the equilibrium curve so that hydrates are dissociated at already lower temperature and higher pressure.

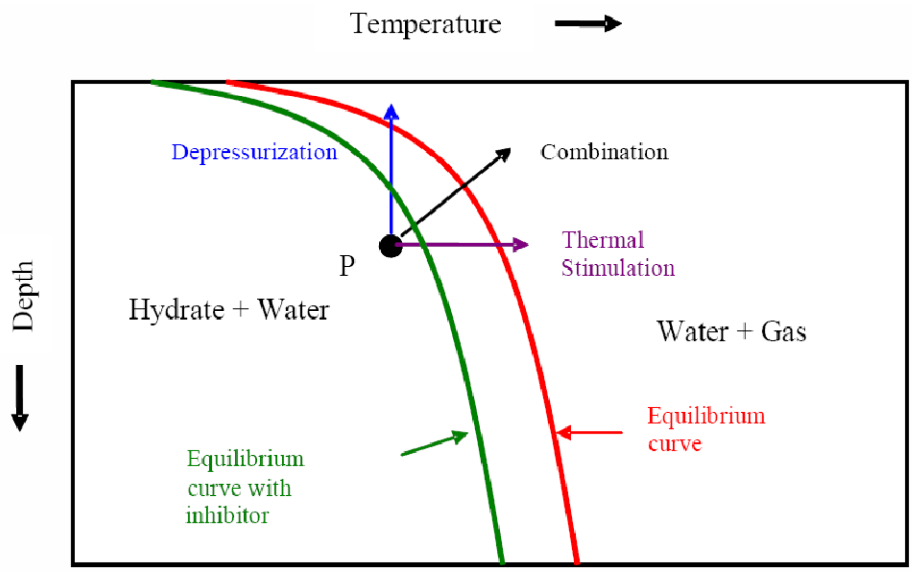


Figure 2-7 Mechanisms of hydrate dissociation (Grover, 2008)

2.8. Classification of hydrate deposits

The accumulation of natural gas hydrate (NGH) is defined as occurrence of NGH in sediments with respect to a stratigraphic capture and/or geological structure. If there are several GH accumulations within a basin they are considered as a GH 'province'.
There are three types of GH accumulations (Milkov, et al., 2002); structural-, stratigraphic- and combination accumulations. The accumulations are distinguished based on the fluid migration and GH concentration within the Gas Hydrate Stability Zone (GHSZ).
Structural accumulations occur where mud volcanoes, fault systems and other geological structures, such as salt diapirs facilitate rapid fluid transport from the underlying layers into the GHSZ. These accumulations occur world-wide. Most of them tend to be located on convergent margins (Figure 2-1).
Stratigraphic accumulations occur in relatively permeable strata from bacterial gas which is generated in situ or slowly supplied from great depth. It is also possible to have a combination of the previously described accumulations.

Structural accumulations
Structural GH accumulations occur in different tectonic settings and water depths. They occur in advective high fluid flux settings (Xu, et al., 1999). Based on sampling and observation of outcropping gas hydrate on the seafloor, it was concluded that these accumulations have many common features (Milkov, et al., 2002). Gas vents (with hydrocarbon gas) from the sea floor to the sea, and chemosynthetic communities are common. Gas hydrates largely occur as plates, pellets and nodules in relatively shallow sediments. In these accumulations the gas hydrate concentration is relatively high. This is caused by the highly permeable fractured routes which allowed rapid transport of gas from great depth.
Gas hydrates (sI & sII) crystallize from gas of thermogenic, bacterial and mixed origin. Of all the hydrocarbon gases, methane is the dominant gas in GH. However other hydrocarbons may also be significantly present in structure II gas hydrates. Gas hydrates coexisting with oil exist in prolific oil provinces.

Figure 2-8 shows gas hydrate accumulations that are localized around active faults and crates of mud volcanoes.

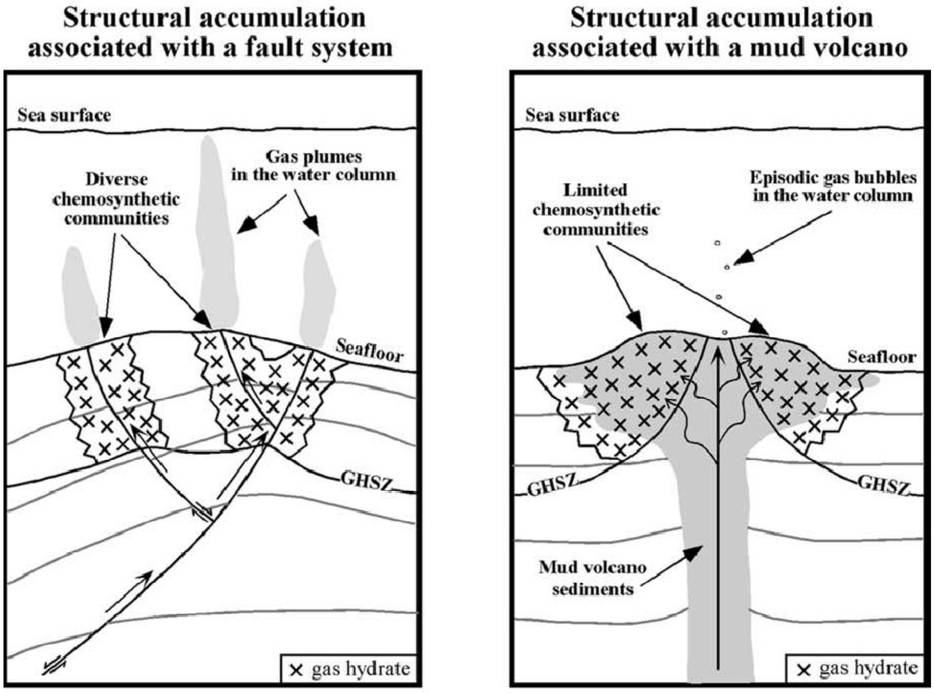


Figure 2-8 Two types of Structural accumulations. Arrows show fluid migration. Not to scale. (Milkov, et al., 2002)

Xu et al. (1999) suggested that the layers of gas hydrate (in the GHSZ) are to be thick because of the high fluid flux rate. The origin of these accumulations can be divided into four groups:

1. Geologic:
    a. Thick sedimentary cover (8-22km), mainly composed of terrigenous sediment;
    b. The presence of plastic shale layers in the subsurface;
    c. A rock density inversion;
    d. The occurrence of gas accumulations in the deep subsurface;
    e. Abnormally high formation pressure.
2. Tectonic:
    a. The rapid subsidence of the sedimentary cover due to the high sediment accumulation rate or by overriding thrust sheets;
    b. The occurrence of diapiric or anticlinal folds;
    c. The occurrence of faults;
    d. Lateral tectonic compression
    e. Seismic activity;
    f. Isostatic processes.
3. Geochemical:
    a. Petroleum generation in the deep subsurface;
    b. The dehydration of clay minerals
4. Hydrogeological, i.e. fluid flow along fracture zones.

These reasons have often been examined together with the mechanisms of their formation. Examination of published seismic profiles has shown that all structural accumulations are formed by two basic mechanisms.
The first mechanism is the formation of a structural accumulation directly on the top of a sea-floor-piercing shale diapir as a consequence of fluid migration along the body of the diapir (case B on Figure 2-9). The second (and more common) mechanism is the formation of structural accumulations as a result of the rise of gas and fluidized mud along faults and fractures (case D1 and D2, Figure 2-9). In this case, sediments with a high fluid content reach the sea floor and form a structural accumulation associated with a fault system or a mud volcano.

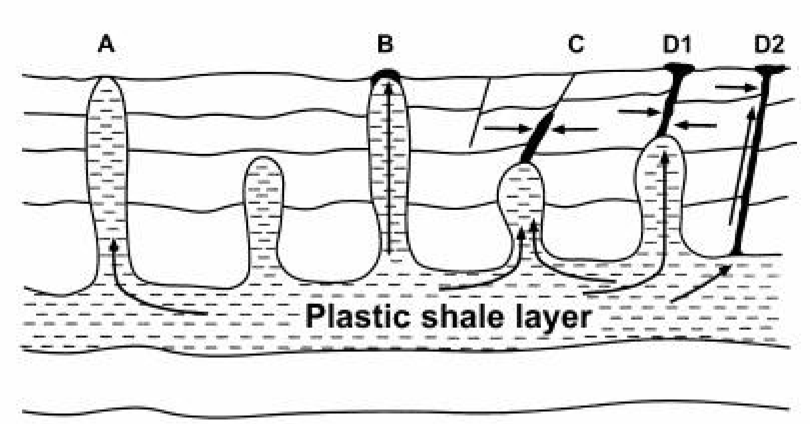


Figure 2-9 Submarine structural accumulations (SA) formed by two basic mechanisms. (A) seafloor-piercing shale diapir without a SA; (B) a SA formed on top of a seafloor-piercing shale diapir; (C) a seafloor seepage; (D1, D2) SAs formed due to the rise of fluidized sediments along faults. Arrows show the migration paths of fluids (Milkov, 2005)**.**

The thickness of the GHSZ will be higher with the presence of heavy hydrocarbon gases (Milkov, et al., 2000). Salinity of pore water has a retard influence on the stability of gas hydrate (Sloan, 1998). Bottom simulating reflectors (BSRs) are not common, because the accumulations are vertically piled and these accumulations do not seal much gas below the gas hydrate layer in contrast with the stratigraphic accumulations (Milkov, et al., 2000). Another reason why BSRs are not common is the disturbed base of the GHSZ which does not parallel the seafloor.

Stratigraphic accumulations
Stratigraphic GH accumulations occur in diffusion dominated- or advective low fluid flux settings (Xu, et al., 1999). The occurrence of these accumulations are in relatively permeable strata (Figure 2-10; a).
The crystallization of the gas hydrate goes smoothly and it occurs mainly as small crystals in pore space. But research showed that it occurs as plate crystals and nodules as well. GH tends to be widely disseminated through the GHSZ and the concentration of GH is relatively low. GHs crystallises mainly as structure I from bacterial methane. Methane is slowly supplied from the depth or is generated in situ. GH occurs in grained sediments with large pore space which facilitated gas migration into this region. This all together makes nucleation of GH possible. Furthermore, GH appears in layers near the base of the GHSZ. Most of the gas hydrate concentrations are likely to occur in low flux advective settings (Xu, et al., 1999).

These accumulations are mostly (but not always) detected with the help of Bottom Simulating Reflectors (BSR), when free gas is present below the GHSZ (Laherrere, 2000).

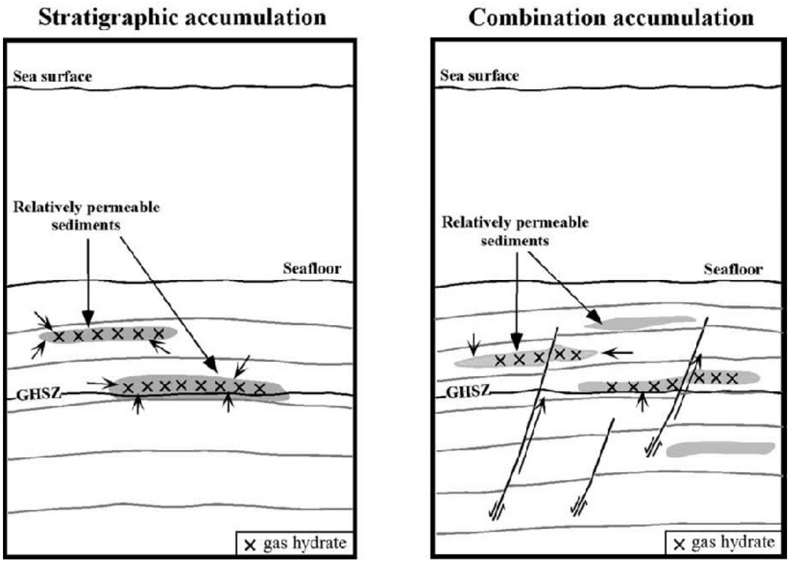


Figure 2-10 Stratigraphic- (a) and combination (b) accumulations. Arrows show fluid migration. Not to scale.(Milkov, et al., 2002)

Combination accumulations

The last type of accumulation is a combination of the previously described accumulations. It occurs in relatively permeable strata, but in contrast with the stratigraphic accumulations, the gas is rapidly supplied from the depth in the section. This happens with the help of faults or salt diapirs (Figure 2-10; b). The fluid flows into the GHSZ goes through shallow faults and into active mud volcanoes. The formation of GH occurs in the relatively permeable sediments.

Conclusion

The stratigraphic- and combination accumulations are currently especially interesting as they can be extracted with (modified) techniques from the petroleum and gas industry. The structural accumulations on the seafloor are far more difficult to extract with the conventional extraction methods from the gas/petroleum industry. These accumulations are best extracted by using techniques more similar to those in mining. In the light of the project the focus will be on the feasibility of the structural accumulations.

2.9. Detection methods

2.9.1. Seismic techniques

Gas hydrate bearing sediments (GHBS) with an underlying free gas reservoir show a Bottom simulating reflection (BSR). This reflection marks the interface between the sediments (GHBS) and the free gas zone. However, not all gas hydrate deposits exist with free gas zones below the gas hydrate bearing sediments. This detection method cannot be applied if there is no free gas below the GHBS.

2.9.2. Coring techniques

Core samplings have been done by various scientific expeditions either onshore or offshore. The main challenge with core sampling is to collect the hydrate bearing cores with little or no change from the reservoir, because with decreasing pressure and/or increasing temperature gas hydrates will dissociate. In the past researchers collected the hydrate bearing sediments in cores but the gas hydrate molecules could not be maintained when the cores were brought to the surface without dissociation. To overcome this hydrate dissociation new tools for collecting hydrates at in situ conditions needed to be developed. During a scientific program (Shipboard Scientific Party, 2003), researchers succeeded to extract the hydrate bearing cores with a certain amount of hydrates in the cores. They used new technology such as 'Pressure Core Sampler (PCS) and 'Hydrate Autoclave Coring Equipment (HYACE).

2.9.3. Well logging

Well logging is used to estimate the concentration of NGH in the sediments. This is based on the unique acoustic properties and the electrical resistivity (Shipboard Scientific Party, 2003).

2.10. Shape of gas hydrates in sediment

In sediments, gas hydrates can occur as small crystals in pore space (disseminated), plates, nodules, veins or as massive fillings (see Table 2-4 and Figure 2-11).
There are some factors that influence the geometries of hydrates in sediments:

- Attendance of faults in the sedimentary layers (Milkov, et al., 2002).
- Flux of migrating gases. The amount of gas travelling through an arbitrarily defined plane in a given period of time. For example, massive hydrate layers occur for high gas fluxes.
- Geo-mechanical stress in the sediments.

In general, disseminated hydrates are found in coarser-grained sediments; veins and layers are found in finer grained sediments.

Table 2-4 Description of gas hydrate in porous sediments (Shipboard Scientific Party, 1996)

Geometry	Description
Layer	Tabular gas hydrate that transects the core conformable to bedding. Its apparent thickness is typically of the order of a few centimetres
Lens	A hydrate layer or other feature with tapering margin
Vein	Tabular gas hydrate feature that transects the core at an angle to the bedding. Its apparent thickness is of the order of a few centimetres
Veinlet	Thin, tabular gas hydrate ~1 mm thick or less, commonly present adjacent to veins or layers and oriented in mutually orthogonal directions
Nodular	Spherical to oblate features typically 1-5 cm in diameter
Disseminated	Hydrate grains less than 3 mm distributed throughout the sediment matrix
Massive	The presence of hydrate in core greater than ~10 cm in thickness and with less than 25% intercalated cement

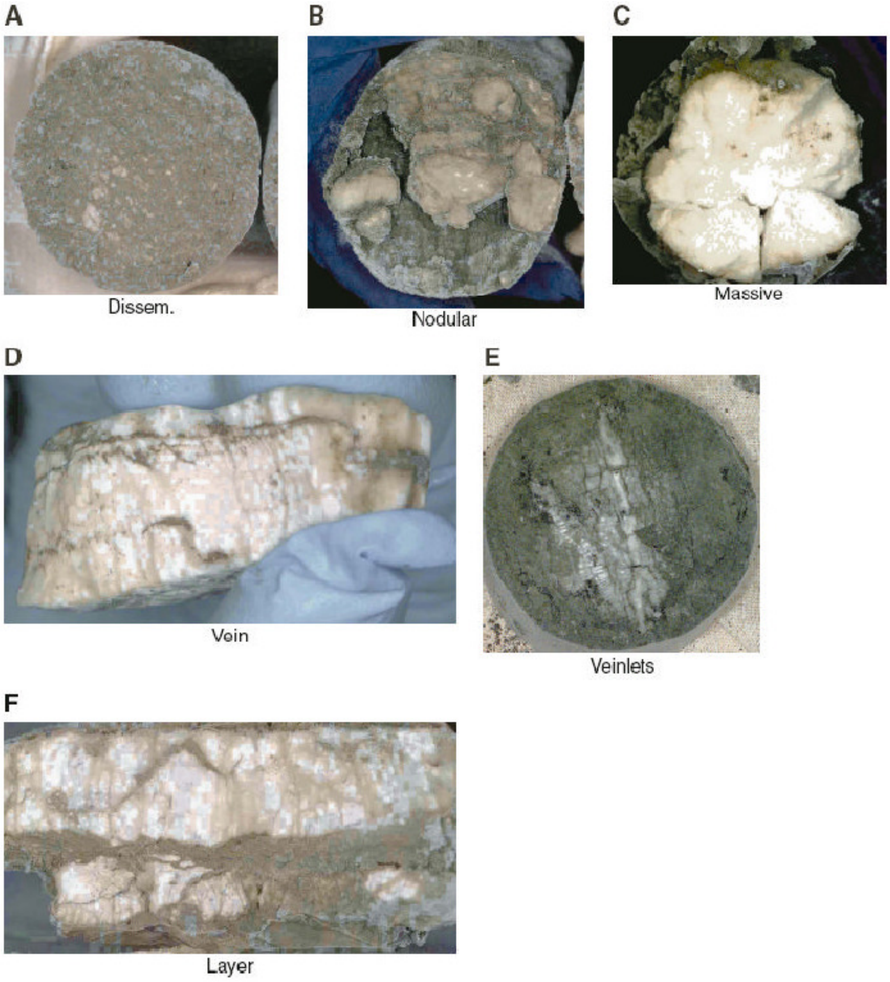


Figure 2-11 Different types of geometries of gas hydrates (Shipboard Scientific Party, 1996)

3. Actual examples of gas hydrate resource on the sea floor

3.1. Preliminary qualitative analysis of different gas hydrate deposits world-wide

Milkov and Sassen (2002) made a qualitative analysis of different hydrate accumulations. It is proposed that the U.S. Geological Survey (USGS) resource/reserve classification scheme for minerals be applied for natural gas hydrate (NGH) accumulations and provinces (Figure 3-1). There are two main criteria for this classification:

- Geological assurance of NGH occurrence (vertical); and
- Economic feasibility of NGH recovery (horizontal).

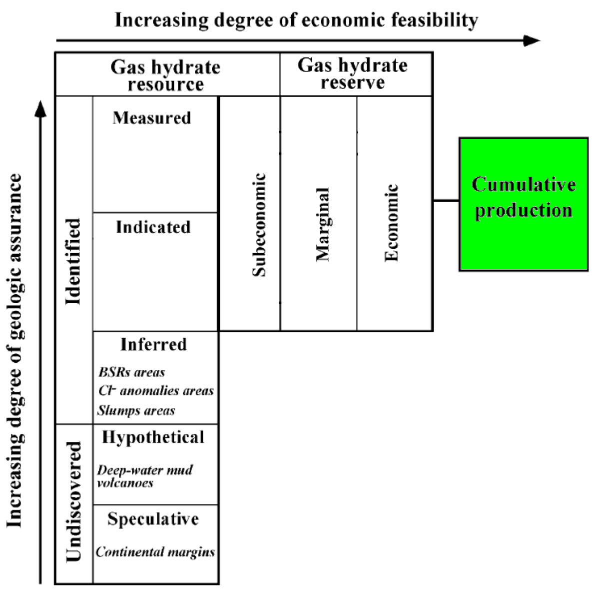


Figure 3-1 Scheme of Resource vs Reserve classification for natural gas hydrates. (modified from Milkov and Sassen (2002))

Geological assurance

Table 3-1 shows a description of different categories. *Undiscovered NGH resources* are deposits which could have a hydrate resource but it is not proven. This category is subdivided into two categories; (1) speculative NGH resources and (2) Hypothetical NGH resources.

Another main category is *Identified NGH resources*. Certain characteristics (location, quantity and other characteristics) are known or estimated with the help of different detection methods: geological, geochemical and geophysical. Identified resources are subdivided into three categories; (1) Inferred-, (2) Indicated-, and (3) Measured resources.

Table 3-1 Geological assurance of undiscovered and identified resources(Milkov, et al., 2002)

Identified	*Measured*: NGH resources in which the volume of hydrate bounded gas is defined by drill holes and cores. The content of hydrate-bearing sediment is estimated by detailed sampling.
	Indicated: include NGH deposits that have been sampled by drilling, coring or by research of a submersible. The volume of a resource is not known, because of too few data whereby it was impossible to give an accurate estimation of resources.
	Inferred: include identified NGH deposits which have not been directly sampled by coring or drilling. The evidence of NGHs were found with the help of different detection methods (e.g. BSRs)
Undiscovered	*Hypothetical*: include undiscovered NGH deposits that are similar known NGH deposits. These accumulations should have similar geological features. The estimated resource is hypothetical because it is an analogy between sampled hydrate-bearing mud volcanoes and other geologically similar features.
	Speculative: include undiscovered NGH deposits that could be present at favourable conditions (i.e. organic matter) and geological settings (continental margins), but no evidence for NGH has been found so far.

There are some natural gas hydrate (NGH) resources that are characterized by the highest degree (measured natural gas hydrate resources) of geological assurance and may be subjected to an economic analysis.

Economic feasibility

If a resource falls in an 'indicated' or 'measured' geological assurance it is interesting to do an economic feasibility study. The feasibility is subdivided into three categories that are based on the increasing degree of recovery.

- Sub-economic NGH resource } Natural gas hydrate resource
- Marginal NGH reserve
- Economic NGH reserve } Natural gas hydrate reserve

Sub-economic resources are NGH accumulations for which, based on the market condition of the time, production is not economically valid. But the production might become economically justified if the projected feasible market condition and the conditions for the investment environment improve.

Marginal Reserves are accumulations that are close to the current market conditions, but they may not be economically valid yet. However these reserves would be producible if the economic and/or technological factors change.

Economic reserves are accumulations where gas hydrate recovery is profitable under the defined investment assumptions. Technological, economical and geological factors affect the viability of gas hydrate extraction.
More detailed quantitative economic analysis is necessary to determine if a reserve is profitable for gas hydrate productions. The next sections list the qualitative analyses of three different NGH deposits of structural accumulations.

3.1.1. Hydrate Ridge (Oregon, USA)

The Hydrate Ridge is a widespread area (375 km^2) with a high concentration (20 – 60%) of gas in the gas-hydrate bearing sediment at water depths of 700 – 1000m. The volume of this resource has not yet been estimated. Nevertheless, the expected volume is similar to reserves of a large or giant gas field (10^{11} m^3). Figure 3-2 shows the bathymetry of the Hydrate Ridge.

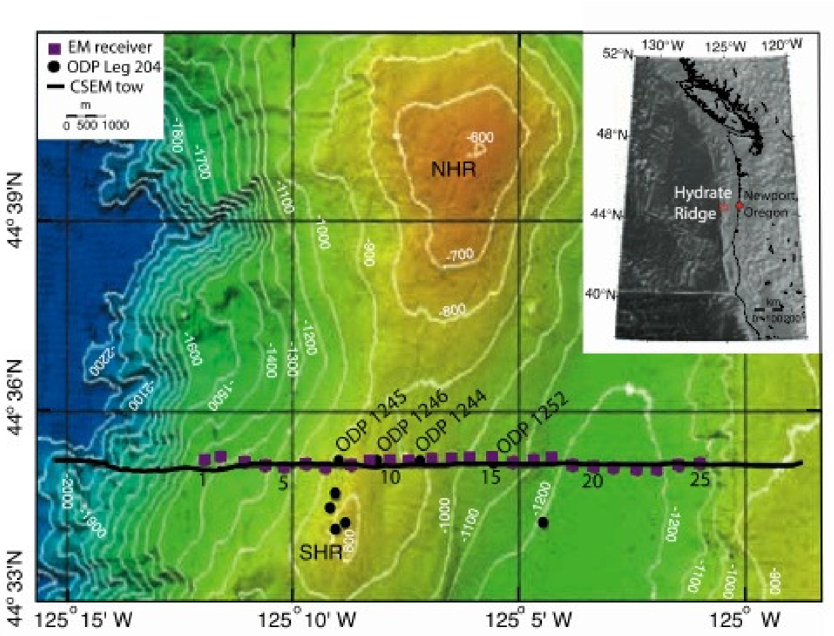


Figure 3-2 Hydrate Ridge bathymetry map (Hydrate Ridge Experiment, 2004)

Development costs and production costs should be relatively low because NGHs occur near the seafloor (0 – 200m) at a relatively shallow water depth (700 – 1000m). The economic perspective of Hydrate Ridge is high. However, there is no infrastructure (petroleum and/or gas pipelines) in this region. This results in a significant investment if the extraction of gas (hydrate) is realized. Another aspect is the high concentrations (10%) of hydrogen sulphide which requires advanced technologies to ensure safe recovery and transportation. These factors make the Hydrate Ridge a marginal reserve whereby more detailed analysis is needed before further development.

3.1.2. Haakon Mosby Mud Volcano (Norway)

This accumulation is well studied (27 cores within 1.8 km^2) and is situated at a water depth of 1250 – 1260 metres in the Barents Sea (Figure 3-3). The subsurface depth of gas hydrate occurrence is 0 – 160m. The areal extent is small and the gas hydrate stability zone is shallow. These conditions make this resource insignificant. The volume of the Haakon Mosby Mud Volcano (HMMV) is comparable to a small conventional gas field. The development costs are relatively high and there are no gas and/or petroleum pipelines nearby. This implies that the HMMV is a sub-economic NGH resource.

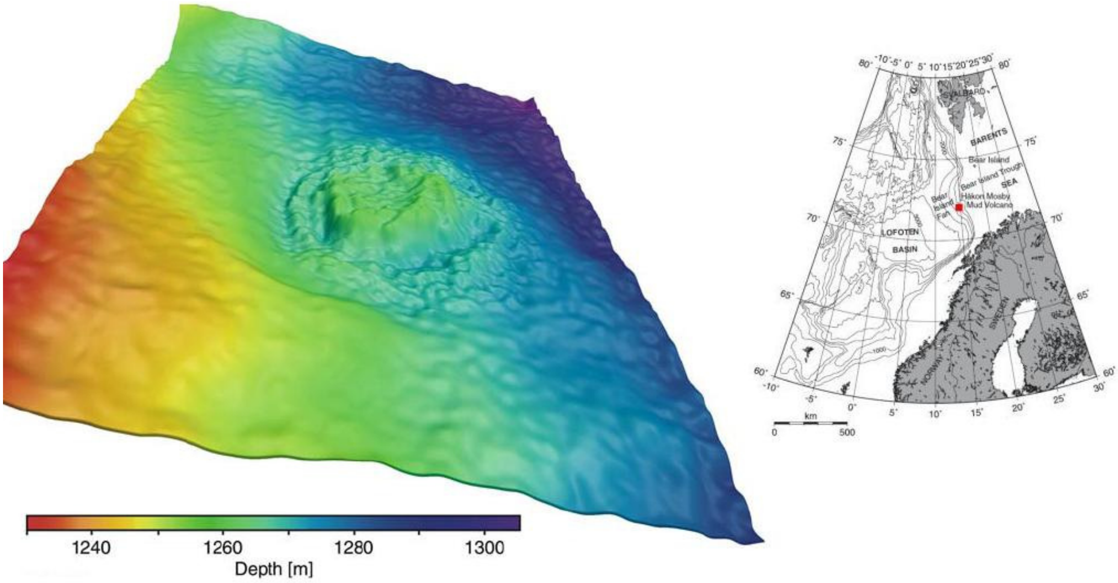


Figure 3-3 A 3-D perspective view of the Haakon Mosby Mud Volcano area. The view direction is from north and a vertical exaggeration of 20 (Beyer, et al., 2005).

3.1.3. Gulf of Mexico (USA)

Two types (structural and stratigraphic) of accumulations occur in the Gulf of Mexico (GOM). Figure 3-4 illustrates the occurrence of gas hydrate sites. Only the structural accumulation is discussed in this report. The stratigraphic accumulations are found at relatively high subsurface depth and are thus not relevant for this study. The structural accumulations occur in shallow sediments with high fracture porosity and permeability.
The NGH concentration (average 20-30%, up to 100%) and the resource volume (8-11 x 10^{12} m^3) for these structural accumulations are high to significant. Nonetheless the average resource density over the GOM is not high (4-5 x 10^8 m^3/km^2), but is suggested to be much greater in some areas (Milkov and Sassen, 2001b) with high NGH concentrations. Development costs could be low because these reservoirs are located at shallow water depths (440 -2500 m) and are near or on the sea floor (0-1900 m).

The costs of gas transportation could be low due to existing petroleum/gas infrastructure. The structural natural gas hydrate accumulations in the GOM are suspected to have a high economical potential because of both favourable factors. The accumulations are scaled as marginal or economic reserves, but still a more detailed economic analysis is needed to assure the profitability of the NGH recovery.

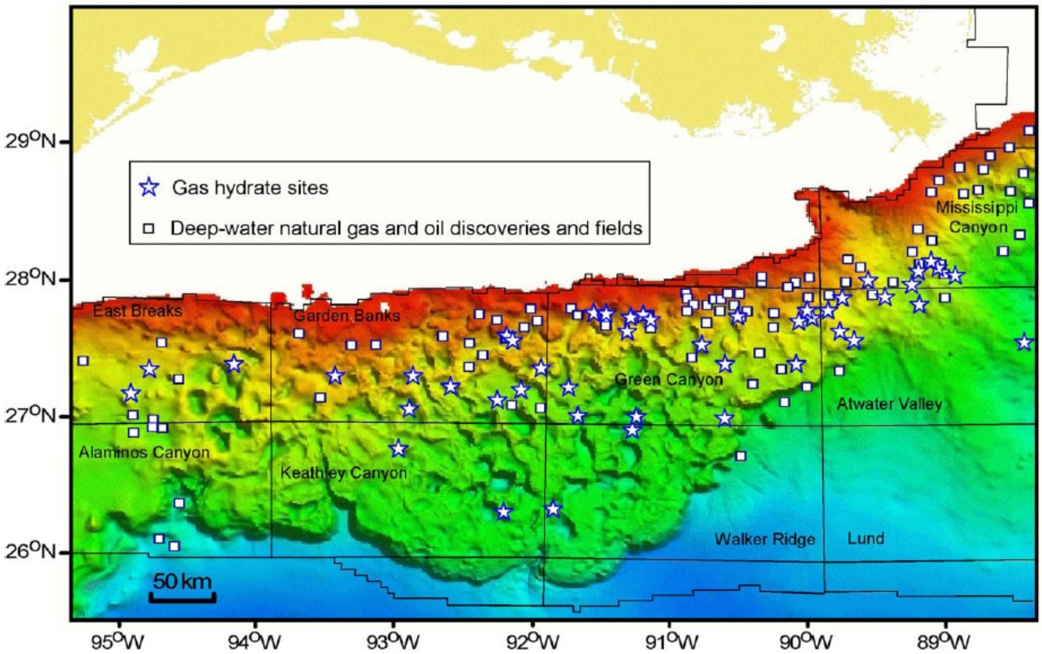


Figure 3-4 Bathymetry Gulf of Mexico (Milkov, 2003)

Individual structural accumulations in the Gulf of Mexico

Milkov and Sassen (2003) estimate the volume of hydrate-bound gas at 7 sites (lease block):

- Green Canyon (GC): 184/185, 234/235 and 204
- Garden Bank (GB): 388
- Mississippi Canyon (MC): 798/842 and 852/853
- Atwater Valley (AV) : 425

The resources in individual NGH accumulations are comparable (by volume) with the reserves in very small to major conventional gas fields.

Various geologic, technologic, and economic factors affect the economic potential of these accumulations. Table 3-2 is a summary of these investigated NGH accumulations.

Table 3-2 Geological characteristics of individual gas hydrate accumulations in the Gulf of Mexico (Milkov, et al., 2003)

Characteristic	GC 184/185	GC 234/235	GB 388	MC 798/842	GC 204	MC 852/853	AV 425
Water depth [m]	500-650	500-670	650-750	807-820	850-1000	1080-1120	1920-1940
Area [km^2]	0.45	0.61	3.2	0.27	26.13	1.94	5.65
Depth of gas hydrate occurrence [mbsf]	0-390	0-400	0-495	0-580	0-640	0-780	0-380
Observed gas hydrate concentration in sediments [vol%]	5-20 (up to 90)	5-90	<15	<15	>30	>30 (up to 100)	>30
Resource [x 10^8 m^3; tcf]	4.9-15.9; 0.017-0.056	18.4-36.8; 0.065-0.13	31.2-237; 0.11-0.84	4.7-14; 0.017-0.050	251-1260; 0.9-4.5	114-227; 0.4-0.8	160-320; 0.6-1.1
Average gas hydrate resource density [m^3/m^2]	1100-3500	3000-6000	1000-7400	1700-5100	1000-4800	5900-11,700	2800-5700
Average gas yield of hydrate bearing sediments density [m^3/m^3]	3-9	7.5-15	7.5-15	3-9	7.5-15	7.5-15	7.5-15

3.2. Overview examples

Table 3-3 illustrates a summary of all the findings in section 3.1.
Figure 3-5 shows the scheme of resource/reserve classification for these three deposits and shows that the gas hydrate sites in the Gulf of Mexico have the potential to be a gas hydrate reserve which can be produced economically. Based on the potential of the gas hydrate site in the Gulf of Mexico, one structural accumulation will be highlighted and will be used as an example for this pre-feasibility study. The next chapter gives more information about the chosen deposit.

Table 3-3 Characteristics of gas hydrate accumulations and provinces (Milkov, et al., 2002)

Characteristics	Structural accumulations		
	Gulf of Mexico	*Hydrate Ridge*	*Haakon Mosby mud volcano*
Water depth	440 – 2500	700 – 1000	1250 – 1260
Areal extent [km^2]	23 000	375	1.8
Subsurface depth of gas hydrate	0 – 1900	0 – 200	0 – 160
Gas hydrate origin	From thermogenic, bacterial, and mixed gas rapidly migrated from depth below		
Gas hydrate concentration [vol%]	Average 20-30, up to 100	Up to 20 - 60	Up to 25
Resource [m^3]	$8\text{-}11 \times 10^{12}$	Not reported	3×10^8
Average resource density [m^3/km^2]	$4\text{-}5 \times 10^8$	Not reported	1.7×10^8
Permeability		High (fracture)	
Recovery factor		High	
Infrastructure	Well developed	None	None
Economic potential	High	Average to high	Low

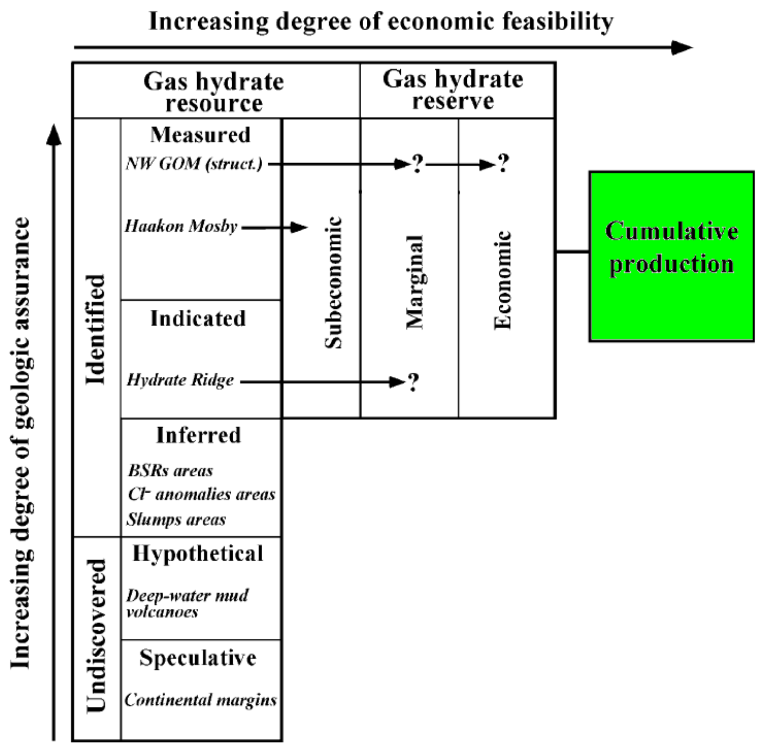


Figure 3-5 Outcome resource/reserve classification of the three deposits (modified from Milkov and Sassen (2002))

4. Deposit Information

From a geological, geometrical and geographical perspective of the natural gas hydrate deposit located on one of the gas hydrate sites in the Gulf of Mexico (GOM). The accumulation is located in the Atwater Valley (AV) and is located in Minerals Management Service (MMS) lease blocks 425. Most information was obtained from studies on the accumulation and provinces in the Atwater Valley. The focus on the Atwater Valley in the GOM was chosen based on preliminary research data shown in Table 3-2. There is a lot of information about this site and a high gas hydrate concentration made it a very interesting deposit.

4.1. Geology

Structural accumulations in the central GOM continental slope were formed during the Tertiary (62 – 2,588 Ma ago). A sea floor mound overlies a shallow salt body in Atwater Valley (AV). The hydrocarbons (i.e. methane, ethane etc.) found their way through the faults and fractures, where they dispersed in the subsurface (0 – 780m) or got lost on the sea floor at a water depth of 1920 – 1940 m. The different types of gas hydrates are described in section 2.10 (shape of gas hydrate in sediments). Figure 4-1 shows a sample of marine gas hydrate from the Gulf of Mexico. Figure 4-2 is a schematic block diagram displaying the structure of the GOM northern continental slope and illustrating the conceptual model of gas hydrate occurrence in the GOM gas hydrate provinces.

Figure 4-1 Chunks of gas hydrate recovered from the Gulf of Mexico (USGS, 2002)

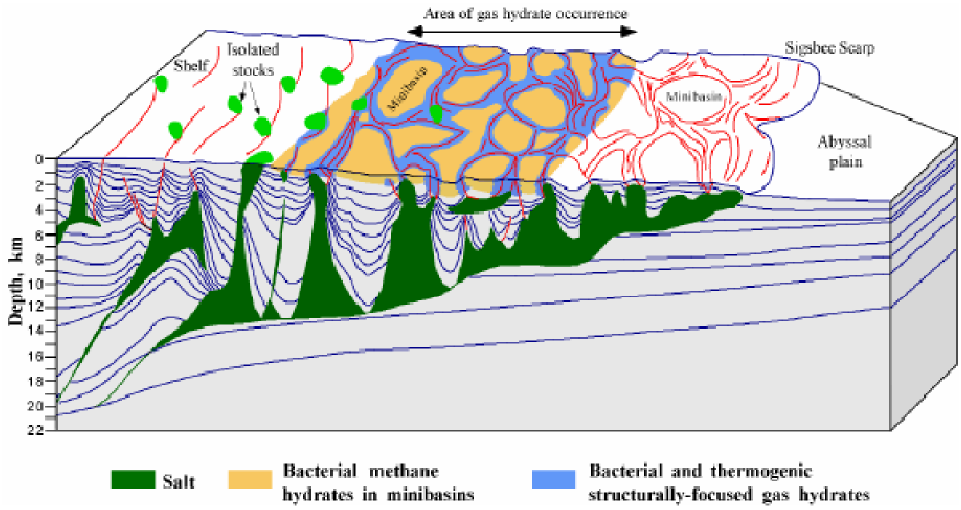


Figure 4-2 Conceptual model for gas hydrate occurrence (Milkov and Sassen, 2001b)

Gas yield of hydrate bearing sediment

The AV-425 is a measured gas hydrate resource, where the average gas hydrate resource density is 2800 - 5700 m^3/m^2 with the occurrence of 0 - 380m below the sea floor. The density of the gas yield in the gas hydrate bearing sediment is between 7.5 – 15 m^3/m^3 at standard temperature and pressure (STP).

Molecular and isotopic composition of hydrate bound gas

The hydrate concentration in shallow sediments of AV-425 is estimated to exceed 30 vol.%. The molecular distribution shows a structure II gas hydrate deposit. Methane, ethane, propane and butanes are present in the GHBS. Table 4-1 shows that methane is the main component (mean = 91.9%), followed by propane (mean = 4.7%), ethane (2.3%), isobutane (1.2%), normal butane (0.8%), and isopentane (0.3%). The $\delta^{13}C$ of methane (mean = -49.3‰) and δDC1 (mean = -173‰) are consistent with thermogenic gas (Sassen, et al., 1999). These data are comparable with other NGH sites in the Gulf of Mexico.

Table 4-1 Molecular (vol%) and isotopic (‰) composition of hydrate bound gas in the AV-425 (Sassen, et al., 2001)

Accumulation	C_1	$\delta^{13}C_1$	δDC_1	C_2	C_3	i-C_4	n-C_4	I-C_5	n-C_5
AV 425/426	91.9	-49.3	-173	2.3	4.7	1.2	0.8	0.3	<0.1

4.2. Geography & Geometry

The Atwater Valley (AV) is an isolated sea floor vent on the lower Gulf slope. The gas hydrate bearing sediment (GHBS) is located at 27°34' N and 88°29'W and is situated at 1920 – 1930m below sea level. The fluids from depth pierce the thick apron of sediment deposited near the end of the Mississippi Canyon (Mississippi Fan), Figure 4-3 illustrates the gas hydrate resource estimation area of the Gulf of Mexico. Below the GHBS, autochthonous salt and multiple source rocks (Upper Jurassic through Lower Cretaceous) occur at this location (Sassen, et al., 2001)). The middle Jurassic salt bodies are situated at shallow depth and provide conduits for fluid migration.

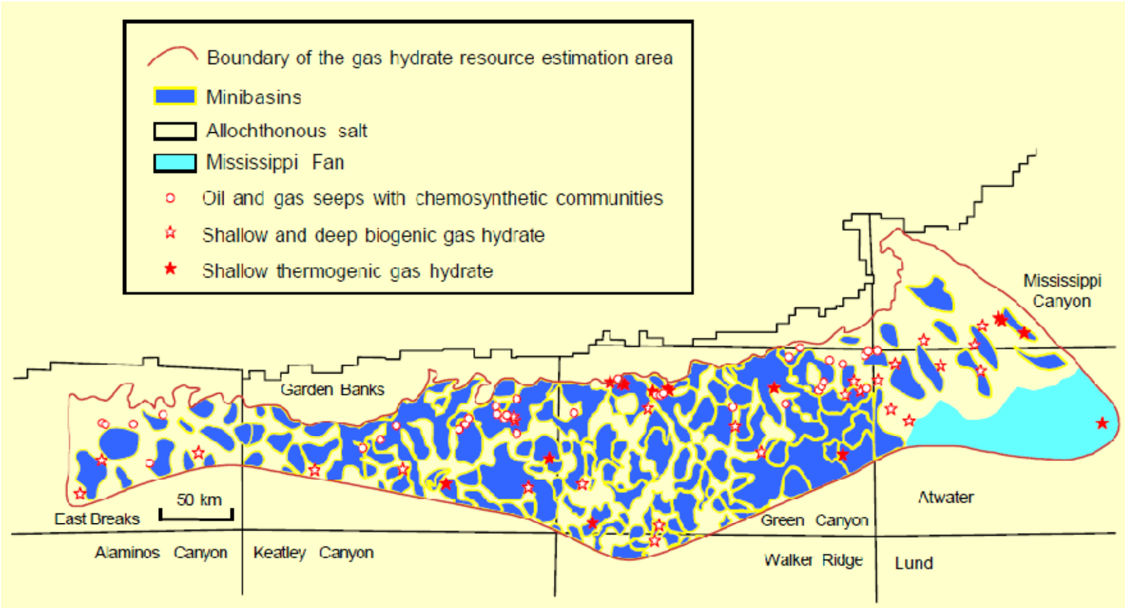


Figure 4-3 Gas hydrate accumulations and provinces in the Gulf of Mexico

Researchers (Milkov, et al., 2003) assumed that gas hydrates occur at the AV-425 mound in an area of 5.65 km^2. The hydrate stability zone has a thickness of 1370 m. However, high gas hydrate concentrations near salt bodies are not expected because gas hydrates do not form in salt (Sloan, 1998). Seismic research shows salt appearances at shallow depths of 380 m below the seafloor (Figure 4-4). So it is assumed that the GH is present only above these salt diapirs. High GH-concentrations (≥ 30 vol.%) occur in shallow sediment. With a minimum gas hydrate saturation of 5 vol.% and maximum saturation 10 vol.%, the estimated volume of hydrate bound gas at the Atwater Valley is 1.6 – 3.2 * 10^{10} m^3. This amount is comparable (by volume) with the reserves in large or major conventional gas fields (Sandrea, 2009). The AV-425 is the deepest occurrence of structure II gas hydrate thus far discovered in the Gulf of Mexico (Sassen, et al., 2000).

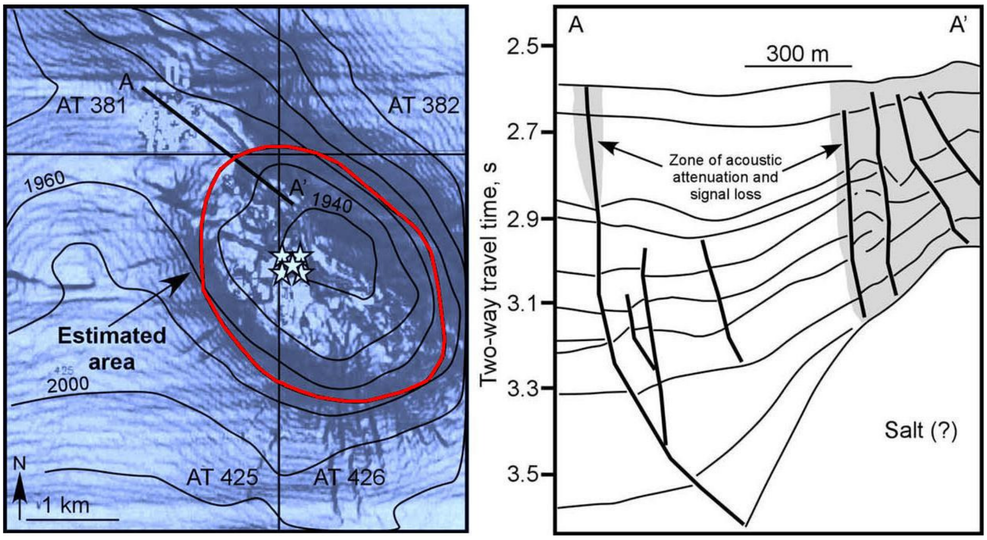


Figure 4-4 Bathymetric map and schematic geologic cross section (Modified from Milkov & Sassen(2003))

4.3. Climate

The maritime climate of the Gulf of Mexico varies from tropical to subtropical, where devastating hurricanes may strike the region. During the summer and autumn the whole area in the Gulf of Mexico is prone to tropical storms and hurricanes. During the year the average temperature varies between 20° - 29°C. The wind direction is generally southeast orientated in the Gulf of Mexico. Rainfall varies hardly throughout the year. Monthly precipitation averages are about 8 – 16 cm.

Tropical storms and hurricanes

Annualy about 10 storms travel the Atlantic Ocean, the Caribbean Sea and the Gulf of Mexico. Half of these storms will grow into 75 mph hurricanes. Figure 4-5 shows that the most active time for hurricane development is mid-August through mid-October.

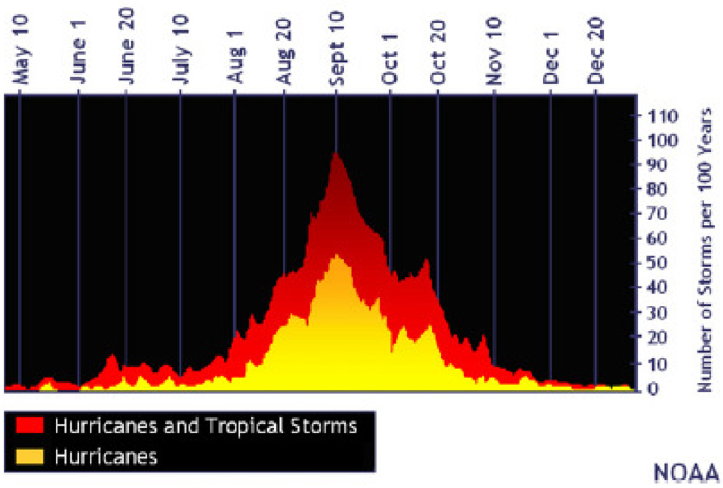


Figure 4-5 Number of hurricanes and tropical storms per 100 years. (NOAA, 2009)

Temperature and Pressure

The average surface water temperature around the Atwater Valley is around 28 °C, while the mean average temperature at the depths which will be mined is 4 – 5 °C. The pressure at the mining depth (1920 – 1930m) is around 195 bar (~19.5 MPa).

Waves and currents

The mean annual wave height in the Gulf of Mexico is 1.0 m (NOAA, 2009). Figure 4-6 shows the wave height on a monthly and annual basis. This includes the tropical storms. However the maximum wave height measured in this period of time (1975 – 2001) was 10.9m during hurricane George in September 1998.

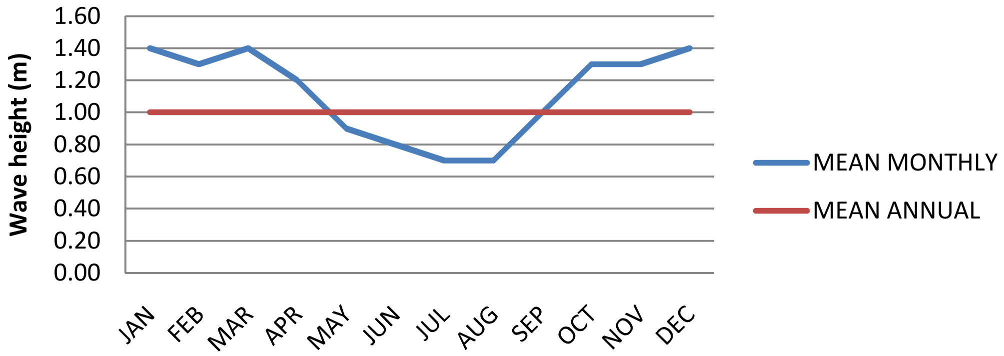


Figure 4-6 Significant wave height Gulf of Mexico from 1975 – 2001 (NOAA, 2010)

Water enters the Gulf of Mexico through the Yucatan Strait, circulates as the Loop Current, and exits through the Florida Strait eventually forming the Gulf Stream. This Loop Current occurs by an interference of the oceanic heat and salt flux from the southeast (Caribbean Sea) with the Mississippi River discharge. This is critical for the regional climate in the Gulf of Mexico area and the water vapour transport towards high northern latitudes. Figure 4-7 illustrates the average ship-drift derived surface velocities and the omega-shaped flow pattern of the Loop current.

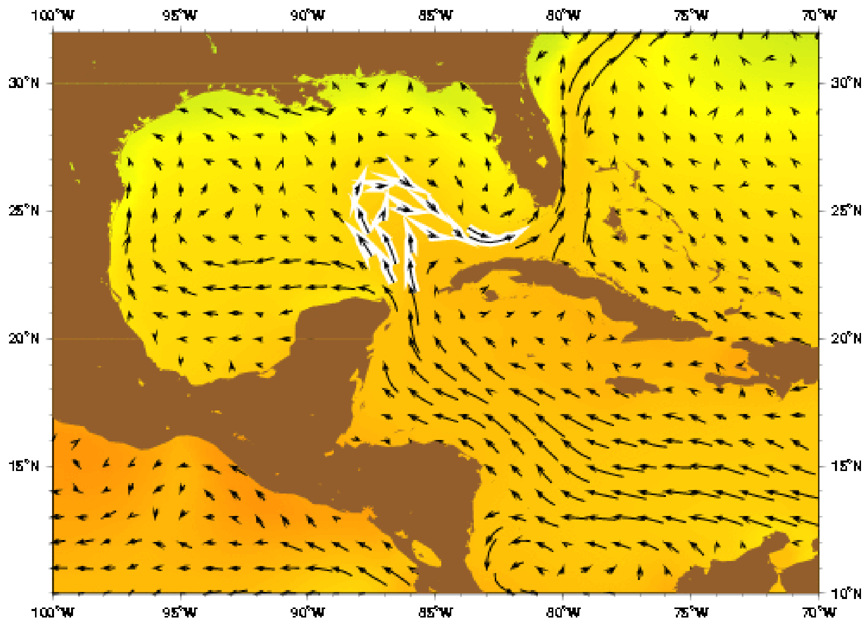


Figure 4-7 Average ship-drift derived surface velocities with the Loop current (Gyory, et al., 2002)

4.4. Exploration

The soil properties of the Atwater Valley (AV) block 13 are known, but not in the case of AV-425. Sufficient geotechnical data are necessary to understand the behaviour of gas hydrate bearing sediments. It is of primary importance to gain insight into the influence of mining the GHBS and the consequences for the site and its surroundings. Core drilling, well logging, bottom simulating reflector (BSR) are techniques to gain important parameters.
During the exploration phase it is also useful to measure the weather conditions such as wind speed, wave height and current profile. These conditions play a major factor in human activities offshore. The Atwater Valley is a hurricane and storm-vulnerable area and can have an enormous impact on the operating costs. However, the Gulf of Mexico is a fairly benign operating environment for most of the year (Kaiser, et al., 2007).

5. General Project Considerations – AV-425

A broad range of aspects can have an influence on the viability of the project. It covers the market outlook, transportation issues, labour requirements, and governmental aspects. Social and environmental issues are also considered.

5.1. The market of natural gas

The global energy environment, seen from the point of view of conventional gas fields, at first might appear to make any near-term development of any unconventional gas resources highly unlikely as viable commercial enterprises. Nevertheless there are already some unconventional gas sources like coal bed methane, tight gas sands and shale gas that have been successfully developed and are important parts of the North American gas supply (Max, et al., 2006). The development of each of these unconventional sources was realised by a small group of enthusiasts. Max et al. (2006) regard natural gas hydrate as being on the same developmental path.

5.1.1. The use of natural gas

Natural gas is primarily used in the industry, as an energy source to manufacture goods (commodities), but also as chemical feedstock to provide for ink, glue, paint, plastics, laundry detergent and in fertilizers. Fiber (e.g. nylon) and synthetic rubber could not be produced without the chemicals derived from natural gas. Furthermore it is used for the heating of buildings (private or business). Another important part is the use of gas for electricity generation. Power plants based on burning natural gas produce electricity more efficiently and with lower emissions than coal power plants. Natural gas is also used as a fuel for the transport sector.

5.1.2. The Natural gas price

The natural gas price was retrieved from the website of New York Mercantile Exchange (NYMEX) and is based on the delivery at the Henry Hub in Louisiana. The average prices are based on the US dollar per million British thermal units ($/mmBtu). Information on composition, regulations and restrictions was obtained from the NYMEX (2010). Natural gas quality specifications can be found in section 7.3.

The Henry Hub natural gas price was US$ 4.2 per million British thermal units (1 mmBtu = 28.26m^3) on Wednesday 12th of May. Graphs of historical natural gas price changes are shown in appendix C.

5.2. Onshore Support Facilities

For this study Port Fourchon, Louisiana, is used as onshore support base. Both marine and aviation support activities will be done from this location. It is important that the facilities are adequate to support the operational needs. The shore base is equipped with facilities related to warehouse, outside storage spaces, material handling equipment, marine vessel dock space, fuel storage, water storage, communication equipment, security, helicopter pad, waiting room, offices, and vehicle parking lots.

5.3. Transportation

Transportation of personnel, goods, ore and waste to and from the operation sites can be done in a variety of ways. The mining support vessel (MSV) is intended to stay at or near the mining site for the complete duration of the mining. All the necessary supplies will be brought to the MSV during this period.

5.3.1. Personnel and other supplies

Personnel will be transported to the site by a fast crew supply vessel from Port Fourchon, Louisiana to the site. The use of this vessel depends on the demand. Besides offshore crew cabins it also contains enough space for cargo (such as food, materials, lubricants, spare parts, tools, etc). In some cases cargo of equipment will depend on item requirements and delivery time.

5.3.2. Fuel

A Dual-fuel engine will supply the power to the vessel. This engine runs simultaneously on natural gas and diesel fuel oil. The engine can switch from gas to liquid fuel (marine diesel oil or gas oil) automatically in case that the gas supply is interrupted. Natural gas is supplied at a low pressure and is taken directly from the FPSO (floating, production, storage and offloading vessel), while the diesel fuel oil is supplied on a regular basis. This will be contracted out. Costs of fuel transportation will be included in the fuel price.

5.3.3. Ore and Waste

Ore
The processing (chapter 7) of the gas hydrate bearing sediments (ore and waste) will take place on site with the help of a floating, production, storage and offloading vessel (FPSO). Natural gas will be transported by specially equipped vessels. A more detailed description can be found in chapter 8.

Waste
There are different types of offshore wastes:

- Extraction and production wastes (e.g. dredging mud, deck drainage etc.)
- Human derived wastes (e.g. Sanitary wastes, trash and domestic wastes, such as kitchen-, laundry wastes and sink and shower drainage).
- Other industrial wastes (e.g. scrap metal, wood pallets, used chemicals and paint etc.)

Most of the human derived wastes and other industrial wastes will be transported to a disposal site onshore. However in some cases the discharge into the marine environment (sanitary and domestic wastes, and so on), do not play an essential roles in the environmental situation. They are treated and disposed in accordance with the norms regulating discharges from the ship.

Offshore oil and gas facilities are allowed to discharge wastes (e.g., produced water, water-based muds) into the sea as long as they meet the legal requirements. All the other extraction and production wastes (e.g. oil-based drilling fluids and cuttings) are prohibited from discharge by the permits. These wastes will be brought to shore (Veil, 2001).

5.4. Utilities

Communication, power, and fresh and potable water are utilities that will be provided by on board facilities on the MSV. However the costs of communication systems, fresh and potable water are not considered in scope for this study.

5.4.1. Power

The Mining Support Vessel will be equipped with an electrical power generating plant. Most of the power will be generated by gas turbines (from the gas processing) and the diesel engine will be used for restricted backup and essential services. The gas turbine engine has a dual fuel capability with a waste heat recovery unit which supplies saturated steam for heating the process and vessel systems.

Fuel
The supply of fuel is assumed to be contracted out and all costs related to the supply are included in the price per litre. The price of marine diesel oil is assumed to be US$ 632.50 per metric tonne (Bunkerworld, 2010).

5.4.2. Water

The water necessary for the mining operations will be supplied internally. Sea water will be turned into fresh potable usable water with a desalination system. Additional water can be shipped to the vessel when required.

5.5. Labour

The operation requires sufficient workforce. Recruitment will take place mainly in the U.S. and enough skilled people are available.

The production (mining and processing) is planned to run 24 hours a day. The production workforce will work in two 12 hour shifts on a 2 weeks on and one week off schedule (3 shifts system).

Workforce Requirements
The managerial and engineering positions as well as the other crew (e.g. maintenance, operators etc.) are based on annual contacts. A comprehensive overview of the complete workforce including salaries is shown in appendix D.

5.6. Government Considerations

The Minerals Management Service (MMS) is the federal agency in the U.S. Department of the interior that manages the nation's oil, natural gas and other mineral resources in federal offshore waters of the Gulf of Mexico outer continental shelf (MMS, 2009). MMS has to manage and regulate leasing, exploration, development, and production of mineral resources on the outer continental shelf (OCS). Rules concerning exploration, development, and production activities in the Gulf of Mexico are published on the MMS website.

Other departments such as the U.S. Coast Guard, Environmental Protection Agency (EPA), National Oceanic and Atmospheric Administration (NOAA) and Fish and Wildlife Service are involved in the OCS leasing program (including the 'Environmental Impact Statement').

5.7. Social and Environmental Aspects

The U.S. National Environmental Policy Act (NEPA), passed in 1969, requires the federal government to consider the environmental impacts of any proposed actions as well as reasonable alternatives to those actions. In accordance with the EPA, the MMS prepares environmental documents on various actions related to the OCS Program. These documents may be Categorical Exclusion Reviews (CER), Environmental Assessments (EA) or Environmental Impact Statements (EIS), depending upon the nature of the action. This depends on the significance of potential impacts associated with the action.

The policy of MMS is to involve the public in preparing and implementing their EPA procedures. To achieve a successful operation it is important to obtain the support of the people and the government of the United States. It is therefore imperative to do this in an open and responsible manner and it should be accomplished through being, in a social context, responsible and promoting a good relationship with local communities and governments.

New and Unusual Technologies
Deep sea mining in the Gulf of Mexico will be a new technology. In this case the operators must identify this in their exploration and development plans. These technologies are reviewed by MMS for alternative compliance or departures that may trigger additional environmental review.

5.7.1. Site Preparation

Many different aspects have to be taken into account for the intended purpose of the entire project. As in all areas of the Gulf, a wide variety of organisms (e.g. single-celled bacteria and special kind of fishes) inhabit the soft-bottom habitat at almost every depth in the GOM. For this study it is assumed that the sediments lie in an area generally devoid of any surface features and the extraction will have a negligible impact on the ecological function and biological productivity of the surrounding area. However crushing or burial of individual organisms could take place within small areas of a few square kilometres. It is expected that bottom disturbances due to the recovery process (mining, processing and installation or maintenance of the hydrate recovery tool) will not be of a sufficient size or duration to adversely affect the organisms to any significant or permanent degree. Revitalising of organisms takes place from nearby areas, and organisms from undisturbed areas are free to migrate into disrupted areas after the disturbance ceases.

5.7.2. Waste Management and Recycling

The discharge of waste into the Gulf of Mexico is regulated by the U.S. Environmental Protection Agency (EPA) under the authority of the Clean Water Act. No wastes generated during oil and gas operations can be discharged overboard unless they meet the standards required within a National Pollutant Discharge Elimination System (NPDES) permit. All waste types generated from all production activities for the Atwater Valley Project will be either discharged overboard in compliance with NPDES requirements or transported to shore for disposal in permitted or licensed commercial facilities or for recycling. The wastes for overboard discharge and transport to the shore for recycling or disposal are summarised in Table 5-1.

Table 5-1 Wastes treatment from the Atwater Valley Project(MMS, 2008a)

Type of Waste	Discharge Method	Type of Waste	Treatment and/or Storage, Transport, and Disposal Method
Water-based mud	Overboard	Trash and Debris	Transport to shore base for pickup and disposal
Muds, cutting on the seafloor	Discharged at seabed	Hazardous Liquid – Used oil	Transport to shore base for recycling
Sanitary waste	Chlorinate and discharge		
Domestic waste	Remove floating solids and discharge		
Uncontaminated fresh or seawater	Discharge overboard		

5.7.3. Sustainable development

The whole production process is considered as isolated from urban areas; the mining company is not responsible for the social development of communities in coastal areas close to AV-425. The company will only take responsibility for small local settlements which are established as a result of contracted personnel.

After closure activities the FPSO will be decommissioned and resold or customised for operation at other possible natural gas hydrate mining operations. Due to the favourable location of the shore base (Port Fourchon, Louisiana) it might be used for other purposes that are related to marine mining in the Gulf of Mexico.

5.7.4. The purchase of land

A lease agreement needs to be acquired from the U.S. government (MMS) as it lies within its 'Economic Exclusive Zone'. Despite the conditions in the lease contract, it will be impossible to leave the area exactly as it was before the mining. It is necessary to compensate changes to the environment which might influence other industries such as fishery, tourism, and shipping.

6. Extraction Method

The extraction method is applied to extract the gas hydrate bearing sediments (GHBS). The physical-chemical properties of the GHBS determine the design and actual operation.

6.1. Physical Control

6.1.1. Soil properties

Geotechnical properties are of critical importance for the analysis and design of sea floor processes and operations. Critical parameters are slope stability, anchors, fracture (i.e. cutting) and hydrate formation and destabilization. The soil properties of Atwater Valley (AV) block 425 are not known, but the soil characteristics of AV-blocks 13 are known. AV-13 is located at 27°56’N-latitude and 89°17’W-longitude at a water depth of 1290m. GHBS in structural accumulations of the northern Gulf of Mexico are predominantly high porous and low permeable muds and clays (Dai, et al., 2008). For this study the geotechnical properties of AV-425 are assumed to be similar as AV-13. Table 6-1 shows a summary of the AV-13 soil properties that are gained during the “DOE/JIP Gulf of Mexico Hydrate Research Cruise” in 2005 (Fugro, 2006; Winters, et al., 2008; Yun, et al., 2006). The high pH values in these sediments are often associated with the presence of carbonate. These properties refer to a soil that varies from very soft clay on the seafloor to hard clay at the final penetration depths of around 200m below sea floor (Fugro, 2006). Granular sediment was not found during the core sampling. On a geotechnical perspective the undrained shear strength, grain density, bulk density and plasticity index are useful parameters with respect to the excavation device. The grain size distribution of the GHBS is performed in terms of sand, silt, and clay mean grain size and are respectively 2.10%, 25.54% and 72.36%, (Winters, et al., 2008).

Table 6-1 Soil Properties Atwater Valley block 13

Atwater Valley block 13 at 1920m water depth (0-20 mbsf)	
pH[a]	7 – 9
Electrical conductivity of Sediments[a] [S/m]	1.8 – 2.6
Specific surface[a] [m^2/g]	90 – 140
Elastic P-wave velocity[a] [m/s]	~1500
Elastic S-wave velocity[a] [m/s]	20 – 70
Water Content[b] [%]	55 – 70
Plasticity index[b] [%]	55 – 60
Liquidity index[b]	0.5 – 0.7
Undrained Shear Strength[b] [kPa]	5 – 17
Grain density[c] [kg/m^3]	2681 – 2707
Bulk density[c] [kg/m^3]	1614 – 1677
Void Ratio[c]	1.58 – 1.91
Salinity[c] [ppt]	32 – 56

[a] (Yun, et al., 2006)
[b] (Fugro, 2006)
[c] (Winters, et al., 2008)

6.1.2. Uniformity & Continuity

The thickness of the gas hydrate stability zone (GHSZ) is significant. The depth of gas hydrate occurrence is 0 – 380m below sea floor (mbsf), with an observed gas hydrate concentration in sediments of 30% or more. Because there are not enough geological data, the grades of the ore body of the previous section are assumed to be uniform and continuous in thickness.

6.1.3. Geological Structure & Geometry

Figure 6-1 shows the geological structure by means of a bathymetric map (left) and a schematic geological cross-section (right) of Atwater Valley gas hydrate accumulation. The cross-section of the contour interval is 20m. The geometry of the estimated area of the proposed ore body is 5.65km^2, whereby the depth of gas hydrate occurrence is 0 – 380 mbsf. The average gas yield of hydrate bearing sediments is 7.5 – 15 m^3/m^3. Taking all these parameters into consideration makes this reserve (160 – 320) x 10^8 m^3 comparable to large or major conventional gas fields (Sandrea, 2009). With the current technology the maximum extraction depth at a water depth of 2000m is ten metres below sea floor. The assumed maximum resource will be (4.20 – 8.40) x 10^8 m^3 of natural gas.

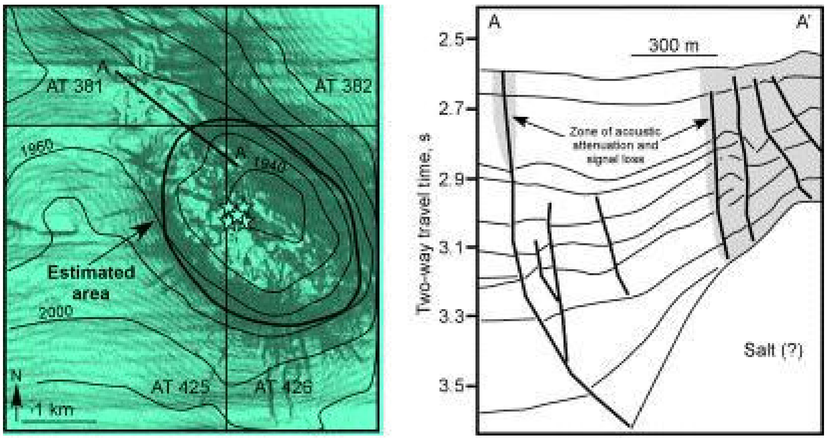


Figure 6-1 Bathymetric map (left) and schematic geologic cross-section (right) of AT 425 gas hydrate accumulation (Milkov, et al., 2003).

For this study the following assumptions on the dimension were made:

- Grades are homogenous;
- Core descriptions suggest high hydrate concentrations in shallow (0 – 100 m) sediments that may exceed 30%. The average gas yield of hydrate-bearing sediments density is 7.5 - 15 m^3/m^3 at standard temperature-pressure (STP);
- Gas hydrates occur at Atwater Valley mound in an area of 5.65 km^2.
- Maximum depth of accessible mining is 10 m at a water depth of around 2000m.

6.1.4. The weather

The operational uptime of deep sea mining is restricted under certain weather conditions. Weather influences are categorized in different sea states ranging from zero to nine (appendix E). For this operation, most of the required annual operating uptime should be less than the maximum sea state, which is set at 5 (Table 6-2).

Table 6-2 Description of sea state 5 (Slagmolen, 2009)

SEA DESCRIPTION	COMMENT	WIND FORCE	WIND DESCRIPTION	WIND SPEED RANGE	
				MIN	MAX
ROUGH	Nominal	6	Strong breeze	Knots 28	Knots 33
				Km/hr 51,9	Km/hr 61,1

WAVE HEIGHT SIGNIFICANT	AVERAGE	AVE 1/10th HIGH	SIGNIFICANT RANGE OF PERIODS		AVERAGE PERIOD
			MIN	MAX	
Metres	Metres	Metres	Secs	Secs	Secs
3,96	3,35	7,01	4,5	15,5	7,9
6,71	4,27	8,53	4,7	16,7	8,6
7,01	4,27	8,84	4,8	17	8,7
7,92	4,88	10,06	5	17,5	9,1

AVERAGE W/LENGTH	Period Max Energy Spectrum	Min Fetch	Min Duration
Metres	Seconds	Naut Miles	Hours
64,62	11,3	230	20
76,2	12,1	280	23
77,11	12,4	290	24
86,87	12,9	340	27

The Gulf of Mexico is a semi-enclosed basin which means a smooth sea most of the time. For effective planning and decision-making reliable forecasts of current weather and ocean current conditions are required. To accomplish this, a good cooperation with the National Weather Service 'NOAA' is vital.

6.2. Selectivity

Grade information, equipment constraints and physical controls of the ore body are one of the main selection criteria in the mining industry. In this industry it is normal that those parts of the ore body that are mined first have the highest grade and are easy to access. This will result in a high initial return of investment. In this study the ore body is considered as a homogenous ore body (i.e. grades and physical controls). It is assumed that the whole ore body can be mined with a maximum depth of 10 metres below the seafloor. The selected ore body is shown in Figure 6-1.

.

6.2.1. Ore recovery estimates

Based on Milkov and Sassen (2003) equipment parameters and the physical controls stated in the previous sections the estimated gas yield of the hydrate bearing sediments is estimated to be 7.5 - 15 m^3/m^3. This is at a standard temperature and pressure. On average a gas yield of 11.25 m^3/m^3 is recovered which covers losses in mining and processing.

6.2.2. Waste Mining and Disposal

Shales and clays can compact closely together and form many random zones of essentially zero permeability that restrict the passage of fluids, even though substantial porosity may exist (Max, et al., 2006). The low permeability makes it hard to mine separately. Thus it was decided not to mine waste and ore separately on the seafloor, but to separate ore and waste on board. It is assumed that the sediments and water are discharged into the ocean.

6.3. Pre-production requirements

It is important to have obtained all legal requirements and permissions before a project starts. The Minerals Management Service (MMS) has prepared a Supplemental Environmental Impact Statement (SEIS) for the oil and gas industry. This statement could be used as a guideline to analyse the potential environmental effects of leasing, exploration, development, and production in the Gulf of Mexico (MMS, 2008). Subsequently an Environmental Management Plan has to be made. Site preparation for deployment of mining machines and a support system could be required. The support facilities that are described in section 5.2 should be finished and additional exploration has to be scheduled.

6.3.1. Planning

Before the production phase can start it is required that the feasibility-, permission- and preproduction phase has finished. Table 6-3 shows that a timeframe of 8 years before the production phase can begin is realistic (Slagmolen, 2009).

Table 6-3 Pre-production activities (modified from Slagmolen (2009))

Activity	Duration	Start	End
Feasibility Phase	*1096 days*	*1-1-2012*	*1-1-2014*
Exploration drilling Phase 1	365 days	1-1-2012	1-1-2013
Pre-Feasibility	183 days	1-1-2013	2-7-2013
Financing	365 days	2-7-2013	2-7-2014
Feasibility	183 days	2-7-2014	1-1-2015
Permitting Phase	*1278 days*	*2-7-2014*	*31-12-2017*
Application for mining lease	730 days	2-7-2014	2-7-2016
Acquire necessary legislative approval	1095 days	2-7-2014	1-7-2017
Environmental & social impact assessment	730 days	2-7-2014	2-7-2016
Environmental & social management plan	183 days	2-7-2016	1-1-2017
Negotiate license to operate	365 days	1-1-2017	31-12-2017
Pre-production Phase	*730 days*	*31-12-2017*	*31-12-2019*
Build processing facilities	730 days	31-12-2017	31-12-2019
Build maintenance facilities	548 days	1-7-2018	31-12-2019
Equipment purchasing and commissioning	730 days	31-12-2017	31-12-2019
Contract negotiations buyers	365 days	31-12-2018	31-12-2019
Contract negotiations suppliers	183 days	1-7-2019	31-12-2019
Workforce recruitment	365 days	31-12-2018	31-12-2019

6.3.2. Requirements

For some activities in the pre-production phase there are several requirements. Equipment, labour and capital are the main requirements.

Equipment
It assumed that exploration, construction and commissioning of processing and maintenance facilities will be sourced out. The other facilities excluding the basic office infrastructure are not required until the start of the production phase.

Labour
There are activities for the pre-production phase that will be done by in-house experts (geologists, mining engineers, legal team, and management). Other activities will be sourced out e.g. exploration operations (e.g. drilling). Consultants, legal counsellors and recruitment agencies will be hired to assist in completing the feasibility study, acquiring legislative approval and recruitment of workforce respectively.

Capital requirements
The estimated capital expenditure of pre-production is US$ 11 million. The main components are the costs for; buildings, infrastructure, exploration and the mining lease.

6.4. Production requirements

The requirements and procedures for the production consist of the following:

1. Excavation: the gas hydrate bearing sediment (GHBS) has to be loosened before it can be excavated. The sediments can be loosened by passive excavation (by using a flow of water) and/or by mechanical tools (i.e. cutters).
2. Picking-up disturbed material: after excavating the GHBS the material has to be picked-up by a hydraulical principle.
3. Lifting (vertical transport): the GHBS is vertically transported, from a seafloor mining machine to the FPSO (Floating production storage and offloading vessel).
4. Mineral processing: the natural gas is separated from solids, water and other waste products.
5. Disposing of waste material: waste products like silty-clays are discharged on the seafloor. Water is discharged after a water treatment process.
6. Transporting natural gas to shore: the gas will be transported through special equipped vessels to an existing oil- and gas platforms and from there to an onshore location.

The first three steps will be discussed in this section. Mineral processing and transportation will be presented in chapter 7 and 8 respectively.

Furthermore a number of technical challenges have to be faced (Verheul, et al., 2004):

- An excavation method that does not destabilise the Hydrate Recovery Tool (HRT) while operating on the sea floor.
- The excavation forces have to be transferred to the sea floor. The sea floor has to be strong enough to carry the device (since action = reaction). Meanwhile, the device has to have sufficient weight to deal with the excavation forces.
- The repositioning of the device must be well controllable since a mining operation at great depth demands tight operational accuracy.
- The ‘Hydrate recovery tool’ must be able to deal with the local circumstances such as the high surrounding pressure, currents, the poor visibility and the geological characteristics of the sea floor.
- A safe way to transport the material through a rigid and flexible pipe to the sea surface has to be found. Thereby the number of pumps and their location along the circuit is important.
- A supporting vessel must be designed that can receive the dredged material, connect and lower the electric power of the excavating device, and accommodate rigid and flexible piping.
- Both the supporting vessel and the excavating device must be able to maintain their position as horizontal forces acting on the piping system that is connected to them.

Some production assumptions and decisions were made with respect to the operation schedule, the equipment selection and design. These are:

- Mineral processing will only take place at the surface support vessel.
- A hydraulic lifting system is used for vertical transport to sea level.
- Gas is transported by vessels, because the site location is too remote and too small to make the construction of pipelines for natural gas prohibitively expensive.

6.4.1. Planning

There are long-, medium- and short term frames when planning the production. Long term planning is the whole lifetime of the mine and annual production schedules whereas medium term planning contains the monthly production and maintenance schedules. Short term planning is on a weekly and daily bases. The focus of this study is on the long term planning. Due to limited actual knowledge in NGH mining more detailed planning horizons are not appropriate.

As a basis for initial planning a calendar year allows 320 working days and 45 days where the system is not operating. Weather conditions and scheduled maintenance are included in the 45 days. The process operates 24 hours a day, 7 days a week. Each shift covers 12 hours, but the effective working hours are assumed to be 10 hours. Based on these time estimates, the total effective working hours for the mining operation are 6400 hours per year.

6.4.2. Equipment

The goal is to recover methane from gas hydrate bearing sediments by means of mining (Max, et al., 2006; MH21 Japan, 2002). In this study the Sea floor Mining Machine (SMM) or Hydrate Recovery Tool (HRT) involves mechanical mining of the GHBS. The aim is to excavate the sediments on the seafloor. Such mechanical mining can be accomplished in a variety of ways. Figure 6-2 shows the conceptual design of a mining system for the recovery of the gas hydrate bearing sediment (GHBS).

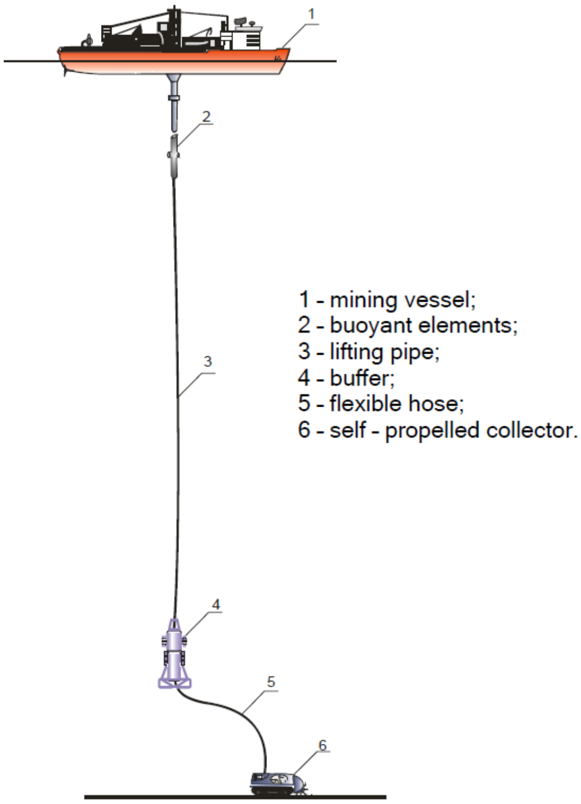


Figure 6-2 Concept of Deep Sea Mining System (Kotlinski, et al., 2008)

The equipment of the GHBS-mining process can be divided into three main components:

- Component 1: *Hydrate Recovery Tool (HRT)* - This is an excavation device in the form of a frame, positioned on the sea floor.
- Component 2: *Vertical Rising Mechanism (VRM)* – This is a flexible and rigid piping system through which the dredged material is transported to the surface.
- Component 3: *Mining Support Vessel (MSV) / Floating Production Storage and Offloading Vessel (FPSO)* – is the floating device.

A breakdown of the required production equipment, together with its respective estimated power requirements, production rate or capacities, operational life and capital costs, are shown in Table 6-4.

Table 6-4 Initial equipment requirements for start up of production phase

Type	Power [kW]	Slurry capacity [m^3 or m^3/h]	Life [yr]	Cost [US$]
2 x Hydrate Recovery Tools	2,750	10,000	10	17,000,000
Vertical Rising Mechanism	18,000	10,000	10	126,000,000
Mining Support Vessel (excl. Topside/processing)	22,800	15,000,000	25	289,650,000

6.4.2.1. The Hydrate Recovery Tool

The aim is to extract the gas hydrates from the sediment. In general, the gas hydrate bearing sediment (GHBS) may be removed from the ocean seabed by several techniques. There are different dissociation methods as described in section 2.7. The first one is to create depressurization immediately above the surface of the hydrates to a point at which decomposition of the hydrates occurs at ambient temperature. The second one is heating to a temperature at which the hydrates decompose with the pressure at the surface of the hydrates. The third one is a chemical reaction (such as glycol or salts) that will cause a shift in the equilibrium curve that results in decomposition. A combination of these methods may be utilized as well. However, in this study the focus is on the mechanical approach that is also applied within the dredging- and mining industry. This method is advantageous because of the greater stability of gas hydrates under high pressure and low temperature associated with the depth of the Atwater Valley. It does not mean that the previously described techniques are not useful.

Criteria analysis of the Hydrate Recovery Tool
The mining tool has to deal with the gas hydrate bearing sediment (GHBS). Hydrate crystals are captured in the open spaces of the silty-clay sediments, but massive gas hydrates can occur at intervals as well.
The specific properties of a soil are an important factor to determine the right mining tool. It is difficult to identify the most appropriate mining tool for a soil. Table 6-5 shows dredging equipment based on the dredging soil.

Table 6-5 Indication of application of mining equipment based on soil type (TID, 2009)

	SOIL			
TYPE OF EQUIPMENT	SILT	CLAY	GRAVEL	ROCK
BACK HOE	R	G	G	R
BUCKET DREDGER	G/R	R/G	R/G	R/G
CUTTER SUCTION DREDGER	G	G	G	R
BUCKET WHEEL DREDGER	G	G	G	NA
GRAB DREDGER	R/G	R	G	NA
BED LEVELLER	G	NA/R	R	NA
PLAIN SUCTION DREDGER	R	NA	G	NA

G=GOOD R=RESTRICTED NA= NO APPLICATION

The sediment is classified as very soft silty-clay. Two dredging techniques are suitable for the extraction of soft silty clays. These are cutter suction dredgers and bucket wheel dredgers. The bucket wheel dredger is similar to a cutter suction dredger. The key difference is a bucket wheel instead of a cutter head as a mechanical cutting device. The cutter is mostly used in wet-mining applications due to its high concentration dredging and to its broad applicability. For this project the bucket wheel is chosen instead of a cutter head because a wheel exerts equal cutting forces when swung in both directions and thus ensures frame stability. This results in a constant output which is favoured for the processing plant development. Furthermore, the clean-up (self cleaning) percentage by using a wheel is higher compared to that of a cutter head (Verheul, et al., 2004). Use of a wheel denotes existing similarities of tool usage and production rates that characterise deep dredging operations and mining.

Figure 6-3 illustrates the concept design that should be suitable for GHBS excavation. The problems described above are minimized by keeping the design as simple as possible.

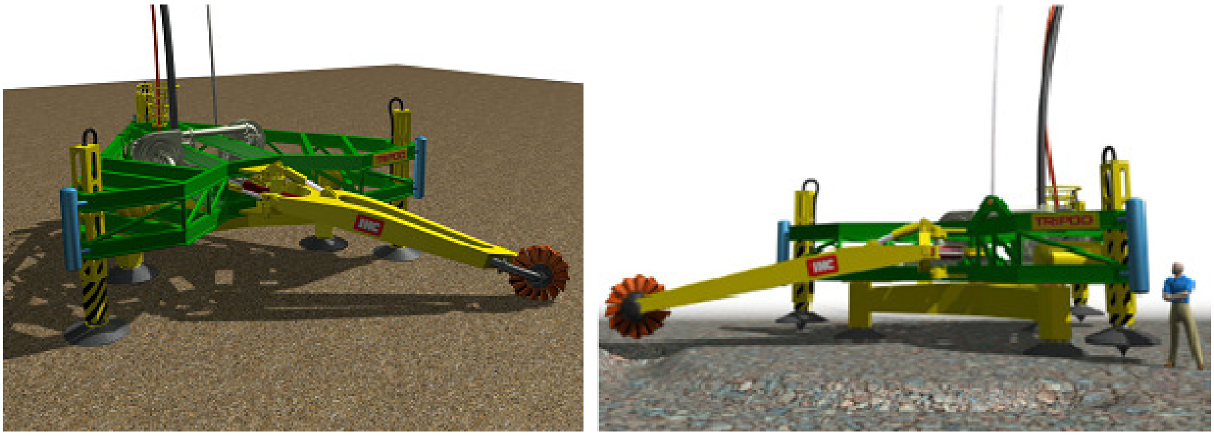


Figure 6-3 Tripod deep sea recovery tool (Verheul, et al., 2004)

The hydrate recovery tool ('TRIPOD') stands on feet. Because the GHBS are close below the sea floor and the structure of the hydrate deposits is relatively homogenous world-wide, a hydrate recovery tool should be universally applicable. It was calculated to mine with two Hydrate Recovery Tools with a total average of 10,000 m^3/hr (5,000 m^3/hr insitu GHBS and 5,000 m^3/hr water) and a maximum production rate of 20,000 m^3/hr based on 15 year production time, reasonable travelling speed and cutting depth for the machine. Its total power requirements are 2750 kW and it costs approximately US$ 17 million.

6.4.2.2. The Vertical Riser Mechanism

Research by van der Kooi (2008) showed that hydraulic lifting is preferred for bulk transportation of material from the seabed at various depths. The Vertical Riser Mechanism (VRM) as stated will be a flexible and rigid pipe riser. The concept is schematically presented in Figure 6-4.

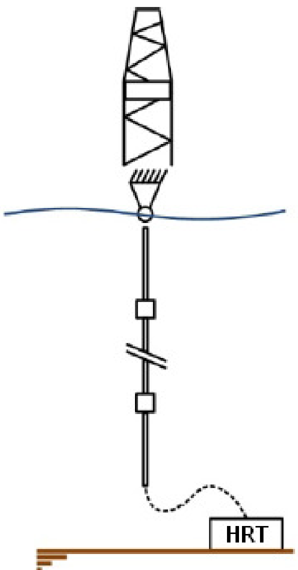


Figure 6-4 Schematic representation of rigid pipe riser (van der Kooi, 2008)

This system consists of:

- Riser pipe
- Booster stations (i.e. centrifugal pumps)
- Pinned connection to the Mining Support Vessel
- Fluidly connection between the Hydrate Recovery Tool and the Vertical Riser Mechanism.

A detailed description of the VRM is shown in appendix F. More information on the proposed VRM can be found in van der Kooi (2008).

Challenges
Besides the main challenges such as, hyperbaric conditions, the slurry transport, the remote control and maintenance, the behaviour of gas hydrates with respect to the temperature and pressure is an important aspect. Hydrates dissociate into gas and water when the surrounding temperature rises and the pressure decreases. This is important for gas hydrate production, but must be avoided during GHBS production, since it would result in gas invading the riser mechanism. The temperature and pressure must be maintained at levels at which the hydrate will not dissociate.

There are different techniques to prevent dissociation (MH21 Japan, 2002):

- Temperature control of the slurry inside the vertical riser mechanism (VRM) by cooling the riser.
- Pressure control of the slurry with the help of pumps to keep the pressure at a given temperature required to stabilise hydrates.
- Add chemicals and other additives that are mixed with the slurry to prevent the dissociation of the gas hydrate. Adding chemicals and other additives have a positive effect during the recovery and vertical transport, but it requires a more sophisticated separation equipment to separate the mixture on the surface.

It is assumed that the pressure control by means of pumping is the most appropriate method to prevent dissociation. Hydraulic lifting is the most suitable mechanism for slurry transport in deep sea mining conditions. The flow of hydraulic transport is induced by pumps. The main advantages of this mechanism are high production capacity, high pick-up controllability and proven technical feasibility (van der Kooi, 2008).

The gas hydrate bearing sediments near the sea floor are stable. In this case the water depth of the mining site is estimated to be between 1920m and 1940m. Hence the hydrostatic pressure is enormous, with the sea floor water temperature of around 4 °C. This indicates that the hydrates are within the hydrate stability zone far away from the equilibrium line (blue line in Figure 6-5).

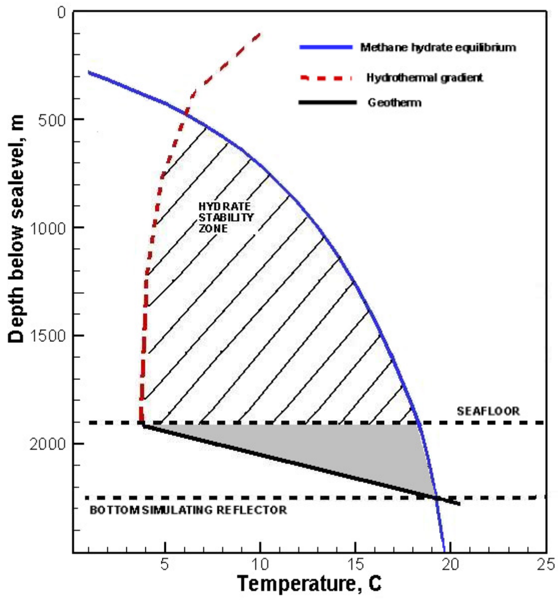


Figure 6-5 Gas Hydrate Stability Zone of hydrate bearing sediment (modified from Grover, 2008)

It is assumed that there is no occurrence of hydrate dissociation when the sediment is disrupted. Possible occuring gas bubbles are collected by the degassing system. During the vertical transport the temperature increases slightly. It is assumed that the maximum temperature in the riser system is 6 °C. The maximum pressure depends on the hydrostatic pressure. It is assumed that the gas hydrates are still stable at 6 °C and at a pressure of minimum 50 bar (5 MPa). Gas in the production line could cause so-called a 'gas lock' in the pumping system, hence it is necessary to avoid the formation of a vapour phase.

Pump Positioning

The centrifugal pump selected for the Vertical Riser Mechanism can be freely positioned at any length of the riser system. A Net Positive Suction Head is an important parameter in the pump production. Whenever the liquid (or slurry) stagnation pressure drops below the vapour pressure, boiling occurs and a gas phase is formed, finally cavitation occurs damaging the riser system. Centrifugal pumps are particularly vulnerable to cavitation and to negative pressure differences, i.e. when the ambient 'water' pressure outside the riser is higher than the pressure inside the risers.

It was assumed that the Gas Hydrate Bearing Sediment contains between 7.5 and 15 m^3/m^3 of gas. Thus during production it is very important to avoid dissociation of gas hydrate crystals. For this study the total pressure loss (Δp) of the hydrate bearing slurry in the system is assumed to be 14 bar per 100 metres. The hydrostatic pressure decreases 10 bar per 100 metres (Vercruijsse, 2009).

To find the optimal distribution two configurations are discussed (Figure 6-6):

a) In "configuration a" all pumps are placed on the seabed
b) In "configuration b" the pumps are distributed over the height of the riser system.

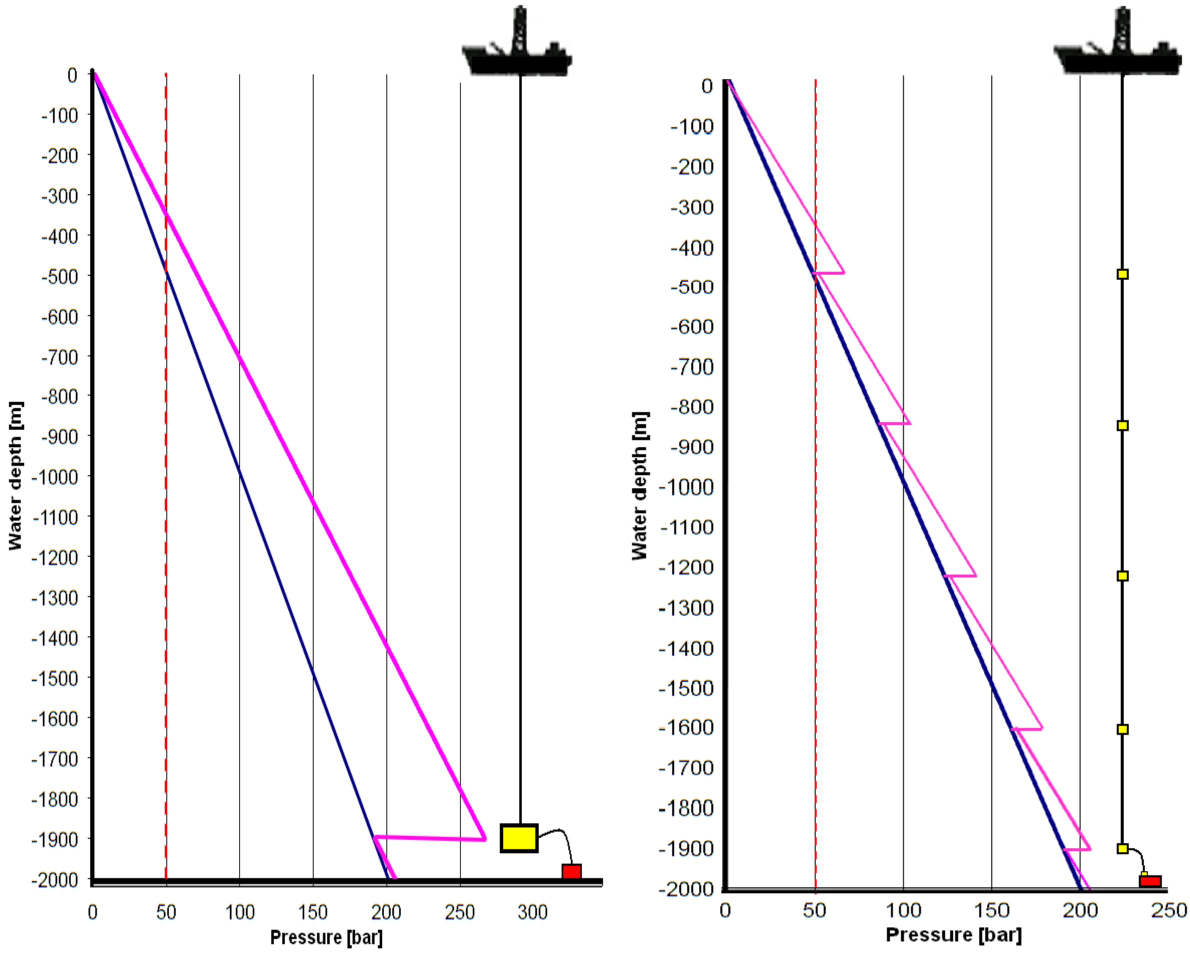


Figure 6-6 Pump configuration
Blue line is the hydrostatic pressure, pink line illustrates the pump/riser pressure and the red dashed line give the hydrate phase stability line at a maximum temperature of 6 °C.

Configuration a
Figure 6-6;a illustrates that the maximum pressure difference between the pressure inside the riser system and the hydrostatic pressure is 75 bar for handling the hydrate bearing sediments.

Configuration b
Figure 6-6;b shows that the maximum pressure for this configuration is significantly reduced in comparison with the previous configuration. Each centrifugal pump adds 15 bar to the riser system (Vercruijsse, 2009). The total pressure delivered by the pumps is 206 bar at 2000m, at the Hydrate Recovery Tool. In this configuration extreme pressure peaks are avoided, hence the required wall thickness of lines and pumps needed to withstand the pressure is reduced. Each pump unit has an average power requirement of 3,000 kW. At a mining depth of 2000m a power requirement of 18 MW is required (Vercruijsse, 2009).

For this study *configuration b* is chosen, because:

- Configuration b is proven technology. For the required pressure differences the application of these centrifugal slurry pumps is fully proven technology in the dredging industry.

- Pressure differences are smaller so that the required wall thickness of lines and pumps to withstand pressure is reduced. This results in a significant reduction in overall weight and investment costs.
- It will be easier to maintain the pump units, because of the multiple smaller and lighter pump units.

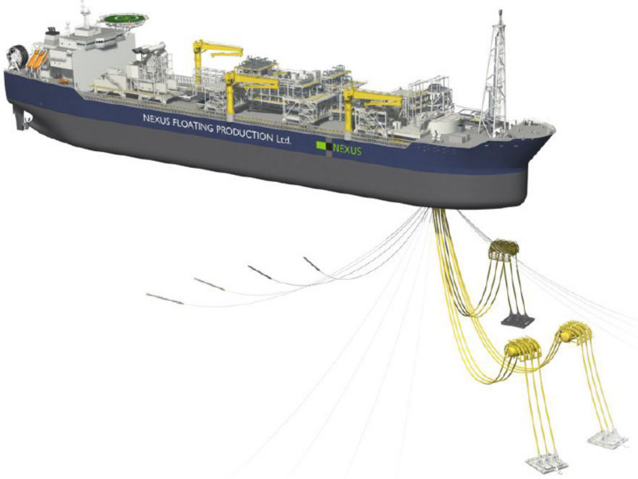
6.4.2.3. The Surface Support Vessel

The Surface Support Vessel is a combination of two offshore (mining) processes, namely gas and petroleum production and diamond mining. Applicable vessels are (Figure 6-7):

a) Large drill ships as used for deep sea exploration (Huisman, 2009);
b) Semi-submersibles (BassTech, 2010);
c) Floating production storage and offloading (FPSO) vessels that are used in petroleum production (Nexus, 2009).

A

B



C

Figure 6-7 Comparable ships
Drillship (a), semisubmersible (b) and a FPSO (c)

In this study the extracted material is a mixture of water, sediments and gas hydrates.

The mining support vessel (MSV) supports the sub-surface activities (van der Kooi, 2008):

- To provide general support (power supply, controls, monitoring, electrics, hydraulics) to the riser system and the HRT
- To commission and decommission the riser and the HRT
- To provide hotel functions for personnel
- To provide structural support for the riser system
- To facilitate all mining operations and all solid/liquid/gas separations
- Temporary storage of natural gas
- Offloading of ore material to the transportation vessel

A detailed functional analysis of the MSV or Surface Support Vessel (SSV) is shown in appendix F. Key components of a SSV and their estimated costs and power requirements are given in Table 6-6.

Table 6-6 Estimated costs and power requirements of Mining Support Vessel

Components Surface Support Vessel			
Component	**Quantity** -	**Cost** [Million US$]	**Power** [kW]
Hull	1	200	15,000
Riser tower / mooring	1	30.5	3,500
Power Pack	1	1	800
Cranes 25t	1	5	
Cranes 20t	1	3.5	
Cranes 5t	3	1	
Dynamic Positioning System	1	0.5	3,500
Hotel facilities	1	20	
Ancillary Projects @10%	1	26.15	
Total		**289.65**	**22,800**

6.4.3. Labour

The wages are divided according to the five key functions:

- Management and administration
- Mining
- Processing
- Ancillary

Maintenance functions are included in the mining, processing and transport costs. The labour costs are shown in Table 6-7. An extended version can be found in appendix D .

Table 6-7 Annual labour costs

Type	In millions US$/y
Management & administration	0.47
Mining & Maintenance	8.05
Processing	4.91
Ancillary	1.87
Total	**15.3**

The annual cost of the required workforce is estimated at US$ 15.3 million.

7. Processing Method

The possible processing methods to retrieve gas from the gas hydrate bearing sediments on the surface are based firstly on the knowledge of firstly the mineralogy of the ore, secondly on certain product specifications and thirdly on the possible processing facility. The input is mainly used to have an indication of cost requirements for further economic and operational analysis.

7.1. Mineralogy

According to section 6.1.1 the sediments can be classified as silty-clay. In Table 7-1 the grain-size distribution is given (Fugro, 2006). Very soft to firm olive gray clay occurs in this area. The clay at the upper part of the gas hydrate bearing sediment is classified as very soft.

Table 7-1 Grain-size distribution determined with a Coulter Counter (Fugro, 2006)

Depth [mbsf]	Sediment Classification	Sand [%]	Silt [%]	Clay [%]
5.00	Silty clay	2.30	27.92	69.78
8.31	Clay	1.01	22.85	76.13
10.01	Clay	1.39	21.93	76.68
12.35	Silty clay	1.65	23.92	74.43

The gas hydrate bearing sediments contain mainly methane (CH_4; 91.9%) and some other higher hydrocarbon gases such as ethane and propane. In Table 7-2 the molecular and isotopic composition of the hydrate-bound gas in the Atwater Valley is given. The gas yield of these gas hydrate bearing sediments is 7.5 – 15 m^3/m^3.

Table 7-2 Gas Hydrate concentration in Atwater Valley.

Accumulation	C_1	$\delta^{13}C_1$	δDC_1	C_2	C_3	i-C_4	n-C_4	I-C_5	n-C_5
Atwater Valley[a]	91.9	-49.3	-173	2.3	4.7	1.2	0.8	0.3	<0.1

[a] Mean values calculated from six gas hydrate samples (Sassen et al., 2001b)

7.2. Alternative Processes

This section shortly reviews the processing of gas hydrate bearing sediments (GHBS). The aim is to extract the hydrocarbon gases in the GHBS. Methane, CH_4, is the main hydrocarbon gas in these sediments, but gases such as ethane (C_2H_6), propane (C_3H_8) and heavier hydrocarbons are present as well. Figure 7-1 shows a schematic diagram of the process routes and products.

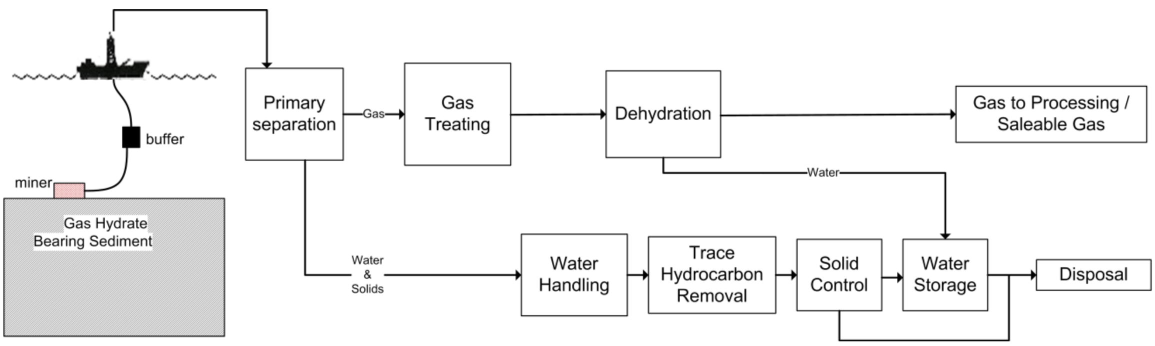


Figure 7-1 Typical gas production process system (modified from Lyons & Plisga, 2005)

7.2.1. Primary separation

At the moment there are no plants to process hydrate bearing sediments. However, several technologies are available to remove liquids and solids from gases. An expansion vessel could be the first-stage separator operating at low-temperatures separating sediments, liquids and gases. This vessel may be equipped with a heating core to dissociate hydrates, or a hydrate-inhibitor such as glycol may be injected into the slurry just before expansion to even enhance the hydrate dissociation (Lyons, et al., 2005). The gas is then further processed. The remainder, namely sediments, water and gas go to the mud/gas separator (Mokhatab, et al., 2006). This is a vertical cylindrical pressure vessel (see Figure 7-2). A series of specially angled baffle plates, stepped from the top to the bottom, initiate the separation.

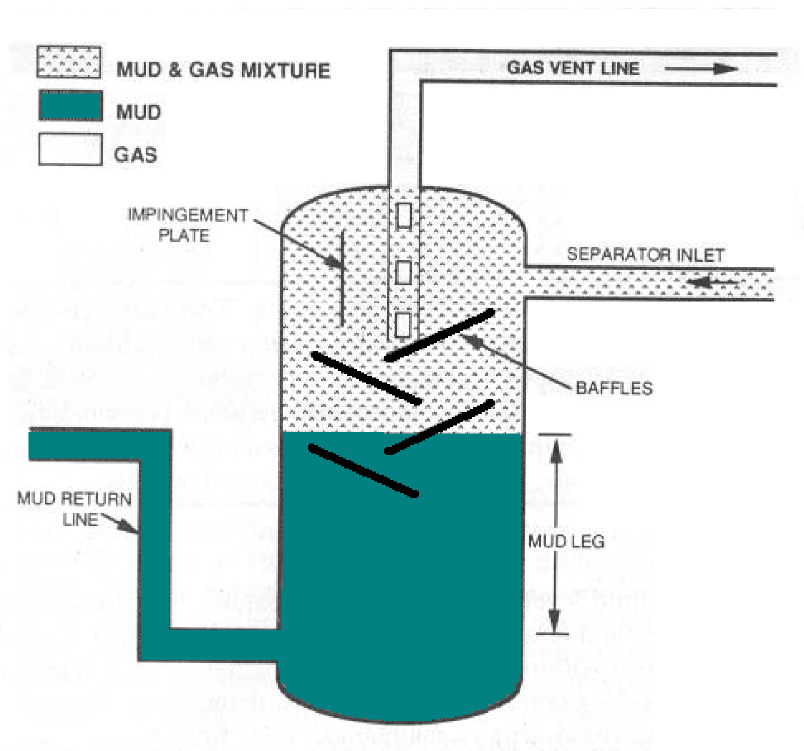


Figure 7-2 Mud/Gas Separator (MacDougall, 1991)

When the mud is routed into the separator, it flows downward successively over each plate. During this process, the entrained gases break out. The released gas is then carried on by vent lines for further gas treating.

7.2.2. Gas Treatment

The next step in processing natural gas is the acid gas treatment. Raw gas contains heavy hydrocarbons, water and other contaminants that need to be removed. Hydrogen sulphide (H_2S) and carbon dioxide (CO_2), and other sulphur-containing species are compounds that require complete or partial removal. These gases are collectively known as "acid gases". Natural gas with H_2S or other sulphur compounds is called "sour gas", whereas gas with only CO_2 is called "sweet gas". Both CO_2 and H_2S are very undesirable, as they cause corrosion and present a major safety risk. A more detailed description can be found in the "Handbook of Natural Gas Transmission and Processing" of Mokhatab et al. (2006).

7.2.3. Dehydration

Water is commonly not completely removed from the gas. However to ensure safe processing and transmission it is necessary to reduce and control the water content in the gas. Below the most important reasons are given:

1. Natural gas can form gas hydrates at low temperatures and high pressure in the presence of water. These hydrates can plug valves and pipelines.
2. Condensation of water from gas streams in the pipeline causes slug flow and possible erosion and corrosion.
3. Presence of water in the gas stream increases the volume and decreases the heating value of the gas and thus the quality and price per cubic metre of gas.
4. Gas sales contracts and/or pipeline specifications often have to meet a maximum water content of 7.0 lb per million cubic feet (mmscf).

Multistage separators can be deployed to ensure the reduction of water in the gas stream. The removal of water 'dehydration' of natural gas is accomplished by cooling the gas so that water vapour condenses from the gas. Other common methods of dehydrating natural gas are liquid desiccant (glycol) dehydration and solid desiccant dehydration. The separated water is transported to storage tanks for discharging and/or disposal. After the natural gas meets the gas specifications, it is a saleable gas.

7.2.4. Solid and Liquid treatment

The presence of solids increases the stability of an emulsion. Removing these solids helps to break the emulsion. According to Mokhatab et al. (2006) solids can be removed successfully by a recyclable backwash filter system. After the solid removal, the hydrocarbons and water are further separated by using so-called coalescence. Figure 7-3 Coalescing in solid-liquids Figure 7-3 shows the steps of the water treatment before disposal. First the solids are removed 'pre-filtration' and than the hydrocarbon droplets coalesce before the final separation is done. Next the produced water and solids will be disposed, as they meet all discharge requirements.

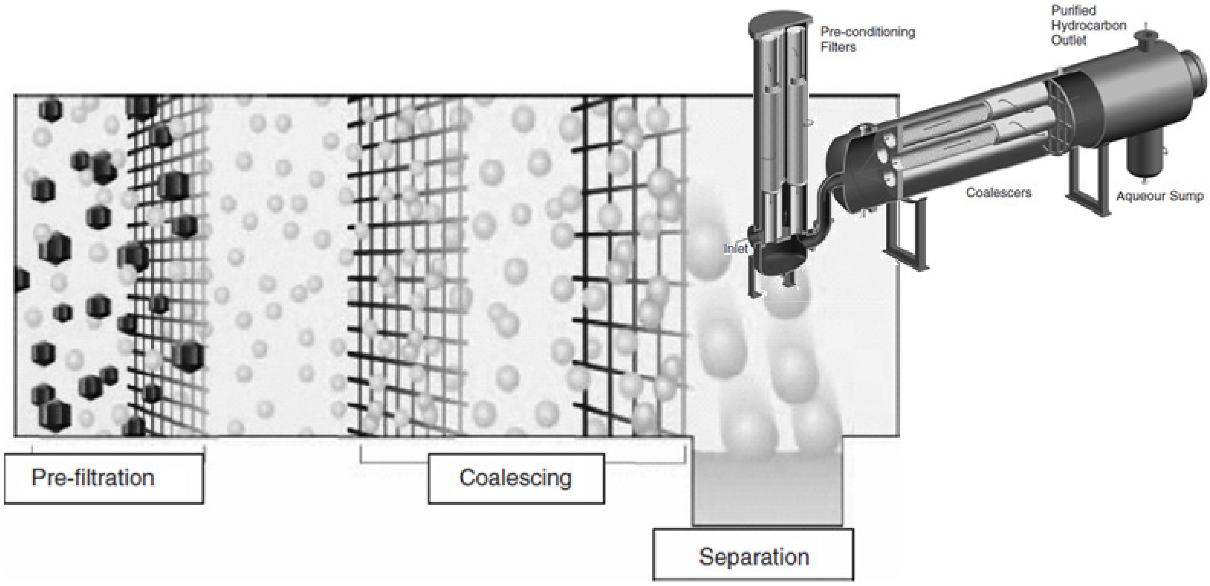


Figure 7-3 Coalescing in solid-liquids (Mokhatab, et al., 2006)

It goes beyond the scope of this study to further elaborate on all these processes. However it should be recognized that these processes are crucial for the viability of the whole mining operation. A more detailed study regarding the separation processes is essential for mining GHBS.

7.3. Production Quality and recoveries

The production quality and specifications of natural gas are well-known.
Natural gas occurs in three forms:

- Conventional gas:
    - *Associated* or *casing head gas*, which occurs in conventional oil fields;
    - *Non-associated* or *gas well gas*, which occurs in conventional gas fields.
- Unconventional (or continuous) gas. Some types of unconventional gas are:
    - “*tight (sand) gas*”, which is found in low-permeable rock;
    - “*coalbed methane*”, which is natural gas that has been formed along with the geological processes that formed coal;
    - “*natural gas from geo-pressurized aquifers*”, which refers to gas dissolved under high pressure and at high temperatures;
    - “*deep gas*”, which is found at levels much deeper than conventional gas;
    - “*gas hydrates*”, which are ice-like structures of water and gas located under permafrost and marine sediments.

The quality and price is determined based on the released energy burning a certain volume of natural gas and is given in British thermal units (Btu)(Mokhatab, et al., 2006). The recovery of natural gas should be good enough to guarantee product quality. The energy content of natural gas is variable and depends on its accumulations, which are influenced by the amount and types of the energy gases (hydrocarbons) they contain. The more noncombustible gas in a natural gas, the lower the calorific value. Analyses of natural gas are done at each stage of the supply chain. A gas chromatographic analysis is used to determine the composition of a gas. The components and their concentrations are converted into a gross heating value in Btu per cubic foot or megajoules per standard cubic metre.

In general, produced natural gas is at first not commercially saleable or suitable for pipeline transportation. In any case, all gases are treated to remove water, solids, or other contaminants. Table 7-3 shows the quality standard of natural gas pipelines in the United States. Gas varies widely in quality and composition. Every reservoir is incomparable and its quality and composition depends on the source field and their characteristics. The main components of natural gas are methane and ethane with a varying amount of heavier hydrocarbons (i.e. propane, butanes, pentanes etc.) as well as carbon dioxide, hydrogen sulphide, oxygen and water vapour. Table 7-4 shows compositions of two conventional natural gases and gas hydrates of Atwater Valley. This shows that the composition of a gas hydrate is comparable with 'gas well gas'.

For this study it is assumed that the processed gas is characterized as 'average gas' by a gross Heating Value of 1035 Btu/scf. This gas is assumed to be a reasonable estimate for an average adjustment gas in the United States (FERC, 2005).

Table 7-3 Representative Pipeline Quality of Natural Gas (Foss, 2004)

	Minimum	Maximum
MAJOR & MINOR COMPONENTS		
Methane [Mol%]	75	
Ethane [Mol%]		10
Propane [Mol%]		5
Butane [Mol%]		2
Pentane plus [Mol%]		0.5
Nitrogen & other inerts [Mol%]		3-4
Carbon Dioxide [Mol%]		3-4
TRACE COMPONENTS		
Hydrogen Sulfide [gr/100scf]		0.25 – 1.0
Mercaptan Sulfur [gr/100scf]		0.25 – 1.0
Total Sulfur [gr/100scf]		5-20
Water Vapour [lb/mmscf]		7.0
Oxygen [ppmv]		0.2 – 1.0
HEATING VALUE		
Heating Value, Btu/scf gross saturated	950	1150

Table 7-4 Gas compositions of conventional gas versus gas hydrate AT-425 (modified from Foss(2004))

	Casinghead (Wet) Gas [mol%]	Gas Well (Dry) Gas [mol%]	Gas Hydrate AT-425[a] [mol%]
Methane	64.48	91.01	91.9
Ethane	11.98	4.88	2.3
Propane	8.75	1.69	4.7
Iso-Butane	0.93	0.14	1.2
n-Butane	2.91	0.52	0.8
Iso-Pentane	0.54	0.09	0.3
n-Pentane	0.80	0.18	<0.1
Hexanes	0.37	0.13	
Carbon Dioxide	0.63	-	
Nitrogen	3.73	1.25	
Hydrogen Sulfide	0.57	-	
Totals	100	100	

[a] Mean values calculated from six gas hydrate samples (Sassen, et al., 2001)

7.4. Topside Process Facilities

For this study it was decided to keep the processing at the mining site, because:

- There is expertise at hand with floating, production, storage and offloading facilities (FPSO).
- Processing requires significant energy consumption, which might be covered partly by the produced gases.
- Most of the waste can be discharged into sea after appropriate treatment (liquids and solids). Only a small amount of waste will be transported to shore for recycling and disposal.

FPSOs are most effective at remote or deepwater locations where marine pipelines are costly. Additionally FPSOs can also be used for smaller gas fields which are exhausted after a few years and which would not justify the expenses of installing a fixed gas platform. Once the field is depleted, the FPSO can be moved to a new location.

The use of FPSOs in the Gulf of Mexico is also advantageous as they can release their mooring/riser turret and sail away in case of an emergency or heavy weather. The turret stays at the location and sinks. Later it can be reconnected to the FPSO.

Figure 7-4 shows process facilities on deck of the vessel. It also shows how the facility can be expanded further and/or adapted. For this study it is assumed that the equipment for the primary separations is installed in the expanded areas (shaded red).

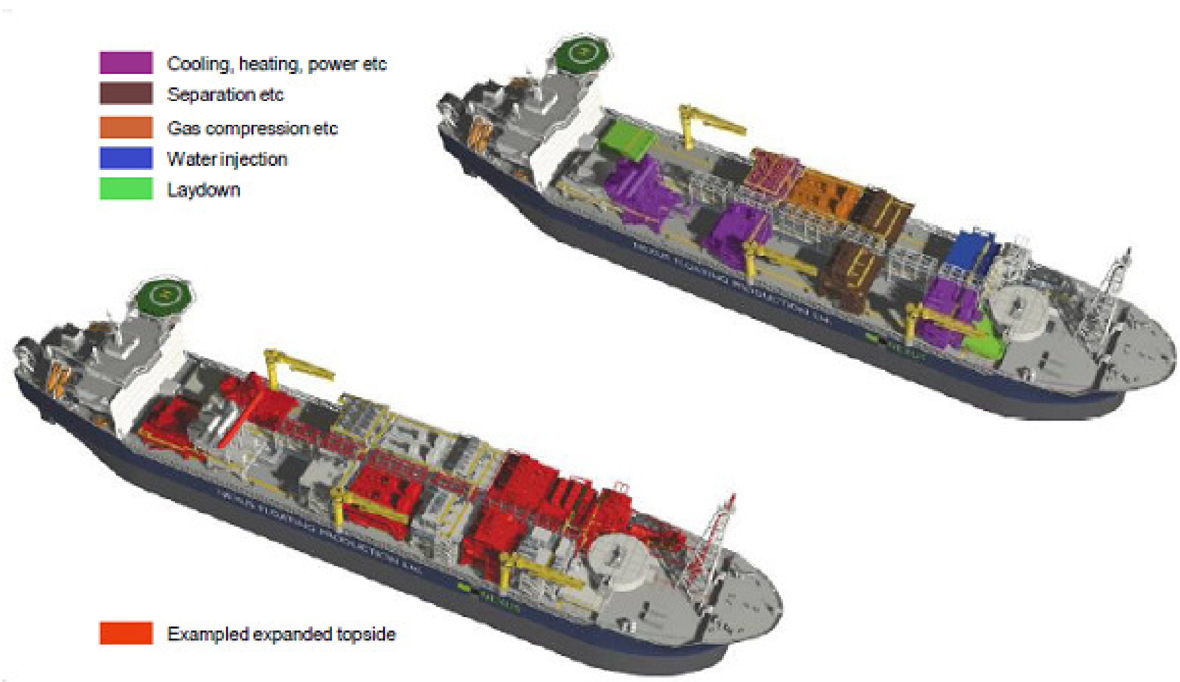


Figure 7-4 Vessel topside process facilities (Nexus, 2009)

7.4.1. Capital Requirements

The capital requirements for the processing facilities are:

- Power plant, Controls and Instrumentation
- Primary Separation
- Gas Treating
- Dehydration plant
- Water handling plant and disposal system
- Solids control and discharge equipment
- Trace hydrocarbon removal plant
- CNG plant with offloading facilities including compressors
- Storage Tank

The costs of all these processes are shown in Table 9-3 in chapter 9.

8. Transportation

Natural gas is an important energy resource. Recently the world-wide consumption has rapidly increased because of the growing demand for clean energy and environmental concerns. According to the 'International Energy Outlook 2009' report of the Energy Information Administration (EIA, 2009) the global total natural gas consumption has increased to an average of 1.6 percent annually, from 104 trillion cubic feet (~ 3 x 10^{12} m^3) in 2006 to possibly 153 tcf (~4.3 x 10^{12} m^3) in 2030 (Figure 8-1; a). In Figure 8-1b the natural gas consumption in North America is displayed. The consumption increases by an average of 0.8 per cent per annum from 2006 to 2030 (Figure 8-1; b). To satisfy such a demand in the future, it is necessary to also exploit smaller and less attractive reservoirs. Different transportation technologies are available to transport the gas to potential markets.

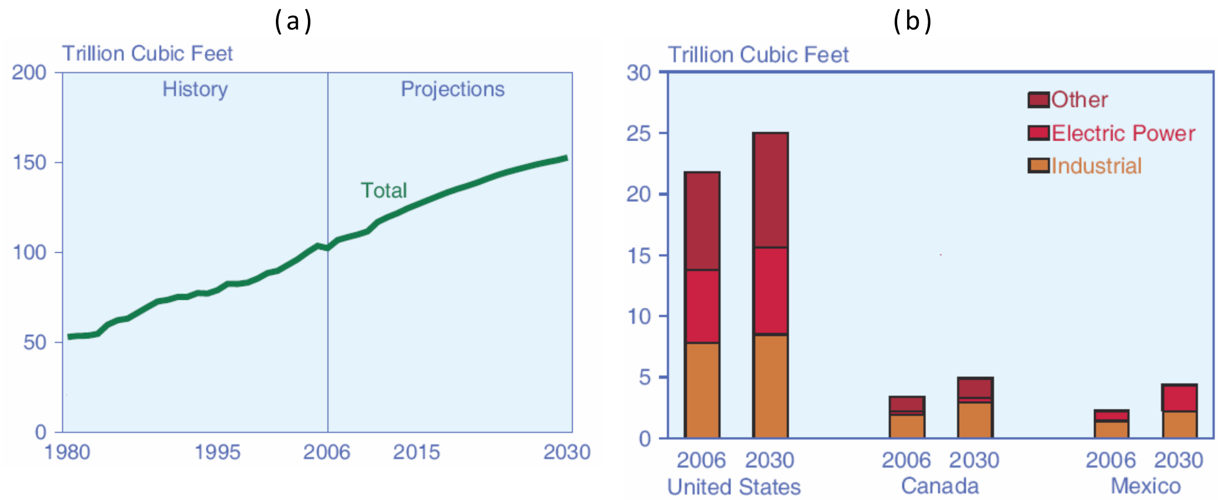


Figure 8-1 Natural Gas Consumption in 2006 to 2030;
globally (a) and in North America by Country and Sector (b) (EIA, 2009)

8.1. Transportation technologies

According to Najibi (2009) there are four options of marine transport of natural gas to the market (see Figure 8-2):

1. As gas through pipelines (PNG),
2. Gas in a different aggregation state to reduce the volume and then transported in vessels:
    - LNG (liquefied natural gas),
    - CNG (compressed natural gas) and
    - NGH (natural gas hydrates)
3. Conversion of gas to other products offshore:
    - Gas to Commodity (GtC) such as production of aluminium, glass, iron. All high levels of energy used per ton of end product;
    - (GTL) processes such as Fischer-Tropsch (F-T) synthetic fuel and methanol production.
4. Conversion of gas to electricity and transmission by cable to market (GTW.

Pipelines and Liquefied Natural Gas (LNG) are currently the most applied methods for transporting gas to the market (Thomas, et al., 2003).

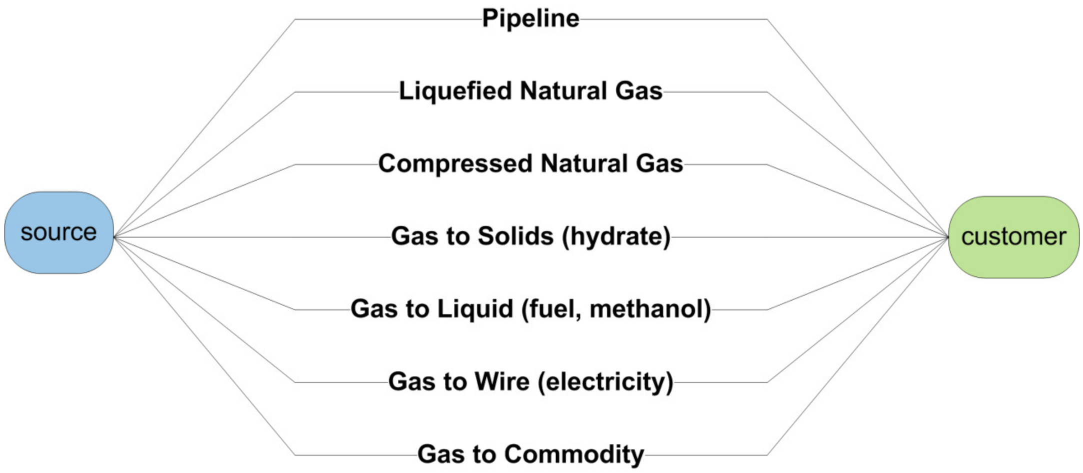


Figure 8-2 Gas Transport Options

8.1.1. Pipeline Natural Gas (PNG)

Offshore gas is transported onshore by pipelines. This option is a very convenient method for gas transportation, but it depends on the infrastructure and is therefore not very flexible. Furthermore the construction of pipelines requires a lot of capital and huge proved gas reserves. This makes it an uneconomic method for small gas fields.

8.1.2. Liquefied natural gas (LNG)

When PNGs are not economically viable, LNG is often considered an alternative. LNG is the liquid form of natural gas. Therefore the gas is cooled to around -162 °C so that it is liquefied. The volume is around 1/600 of the volume of the gas at room temperature. LNG carriers can be efficient for shipping large volumes of gas over long distances. However, high initial expense for the liquefaction plant and associated facilities make LNG often unattractive for medium to small sized resources.

8.1.3. Compressed natural gas (CNG)

CNG is gas that can be transported in containers at high pressures, of around 125 bar for rich gases (significant amounts of higher hydrocarbons) or 250 bar for lean gases (mainly methane). In contrast to LNG carriers, CNG carriers can cope with unprocessed gas.

Although transportation of CNG started a long time ago, until now, the commercial manufacturing of CNG-carriers has not been established, primarily due to the high costs of the pressure vessel. A commercial CNG-carrier is in the implementation stage (Chang, 2001). Compressed natural gas technology provides an effective way for shorter-distance transport of gas. The technology is aimed at monetizing offshore reserves, which so far could not be produced because of lack of a pipeline or because other transportation methods like LNG carriers are too expensive (Economides, et al., 2006).

8.1.4. Natural Gas Hydrate (NGH)

The transportation of gas after transformation, e.g. Gas-to-Solids or transformed gas into Natural Gas Hydrate (NGH), is a viable alternative to LNG or pipeline for natural gas transportation from source to market. NGH is the product of mixing natural gas with water to form a stable snow-like substance. The gas molecules are trapped in the cavities of the ice-like crystalline molecular structure. With respect to transportation and storage, some new potential applications were found (Thomas, et al., 2003; Javanmardi, et al., 2005). Hydrate may be considered as a medium for gas storage, as 1 m^3 of hydrate contains about 160 m^3 (at standard temperature and pressure) gas and $0.85m^3$ of water. The hydrate technology is not yet in the implementation stage and the operational conditions and the processes are not well established.

8.1.5. Gas to Liquids (GtL)

GtL is the conversion of natural gas to a liquid. Typically, syncrude methanol and ammonia are the fine liquids that are be transported. GtL technology is not new. Methane is first mixed with steam and converted to synthetic gas (a gas mixture that contains varying amounts of carbon monoxide and hydrogen) by one of a number of routes using appropriate catalysts (Mokhatab, et al., 2006). The synthetic gas is then converted into a liquid using a Fischer-Tropsch process (supported by a catalyst) or an oxygenation method (mixing synthetic gas with oxygen in the presence of an appropriate catalyst). The produced liquid can be fuel (e.g. syncrude, diesel), or methanol, ammonia, lubricant or some precursor for the manufacturing of plastics (e.g. dimethylether). These liquids are shipped in suitable tankers.

8.1.6. Gas to Wire (GtW)

Currently, much of the transported gas is used as fuel for electricity generation. Electricity generation can be anywhere, so it is possible to do this at or near the source. The produced energy is then transported by cable (GtW) to the market(s). Nevertheless, installing high power lines to reach the shoreline is almost as expensive as pipelines, which makes it less attractive.

8.1.7. Gas to Commodity (GtC)

The production of commodities such as glass, aluminium, iron bars and cement all require large amounts of energy. Gas to commodity (GtC) or transporting the 'gas' as a commodity requires the conversion of gas into thermal or electrical power. This energy is used for the production of the commodities, which is then sold on the open market. The global markets of these commodities are very hectic, i.e. a volatile market with risky prices (volatility high). Hence, much has to be considered before embarking on a project and monetizing gas this way (Thomas, et al., 2003).

8.2. The suitable transport method

As discussed in the previous section, there are a number of routes of transporting natural gas from gas fields to the market. Any gas transport option requires a huge investment in infrastructure and long-term "fail-proof" contracts (≥ ~20 years). For this study the gas is transported to an offloading facility in Port Fourchon. The distance from the mining site and Port Fourchon is approximately 250 km.

"What is the best way to transport the gas from the mining site to the market?"

CNG is the most feasible transportation method. The mining site is considered a small reservoir ((4.20 – 8.40) x 10^8 m^3). CNG could be an option for serving niche markets for stranded gas reserves and for associated small gas fields (on- or offshore) which cannot be exploited economically.

Transportation of natural gas like NGH or CNG is believed feasible at costs lower than for LNG and when transport via pipelines is not possible (Thomas, et al., 2003). The competitive advantage of NGH or CNG over the other options (excluding pipelines) is that the technologies are intrinsically simple, making them much easier to implement at lower costs, provided economically attractive market opportunities can be negotiated. Issues to be considered are the economic risks plus negative effects due to possible terrorist activity, political changes, and trade embargos over long periods of time. Thomas and Dawe (2003) cover many of the essential technical points. Broad economic pointers need to be part of the evaluation to enter the discussion of gas transportation to monetise small natural gas reservoirs. Figure 8-3 shows the range of applications for the currently known or contemplated technologies suitable to monetize natural gas.

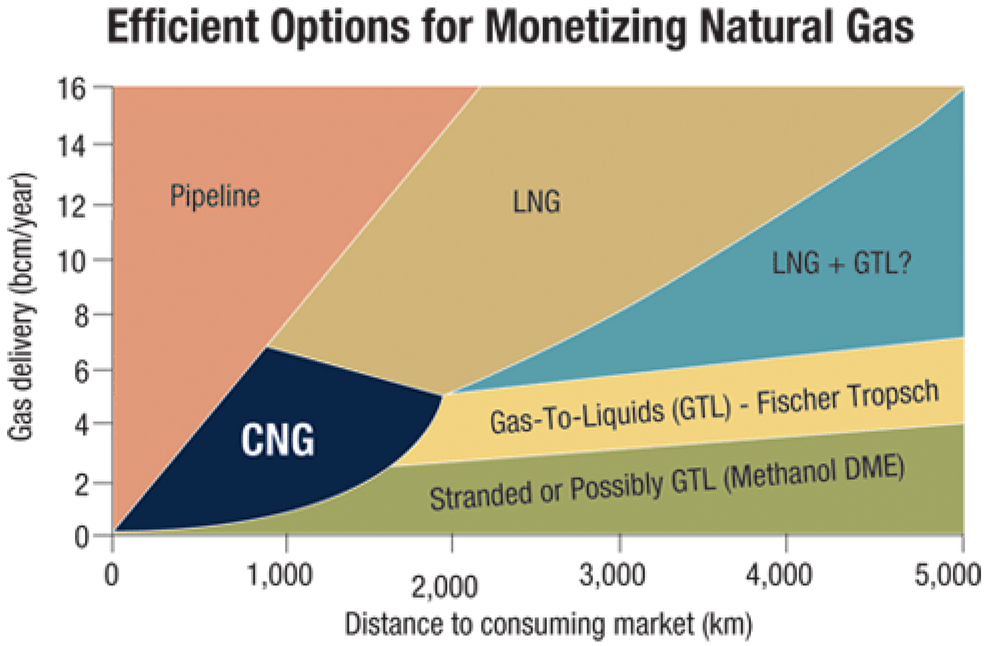


Figure 8-3 Production volume versus distance to market framework for various gas technologies (Wood, et al., 2008)

According to Subero et al. (2004) pipelines and CNG technologies are the best suited to maximize returns of gas transport projects for shorter distances and LNG for long distances. In literature the transportation of gases by means of NGH is seen as a promising alternative. However, the technology is not as mature as the CNG technologies. Therefore, in this study it is assumed that CNG (barge) is the most suitable method (Stephen, et al., 2006). However, NGH can be considered a competitive solution for the future.

9. Project Economics of mining marine GHBS

An economic analysis/model has been developed to provide insight in the profitability of deep sea mining in Atwater Valley. Based on the model, the assumed costs and the capital investment figures a financial appreciation can be made supporting taking a decision on the exploitation of natural gas from marine gas hydrates.
A key parameter in the initial economic viability evaluation is the net present value (NPV) which is calculated using the discounted cash flow (DCF) method. This method translates the future cash flow into a present value. A discount rate is applied to define the present value of a project's future spending.

The assumed project should be capable of producing 32 million m^3 sediment per year, which equates to 360 million m^3 natural gas per year. The input structure of the model consists of a base-case scenario on the exploitation of natural gas from marine gas hydrates of 15 years, which includes:

- General Input (i.e. tax rate, discount rate, production growth, interest rate)
- Capital expenditure (CAPEX)
- Operational expenditure (OPEX)
- Revenue estimation
- Deprecation assuming a straight line depreciation
- Tax estimates
- Interest rate
- Working capital

The output of the model consists of:

- Cash flow model overview
- Net Present Value (NPV)
- Internal Rate of Return (IRR)
- Year of payback

A very important calculation when planning and starting up a project is the cash flow calculation. It shows the consumed financial funds and/or the generated profits over a given period.

A sensitivity analysis was done to evaluate the effect of changes in gas price, gas yield per cubic metre sediment, taxes, royalties and capital- and operational expenditures on the profitability and economic viability of the operation.

Cost estimation and economic modelling was done by using the SME Mining Engineering Handbook (Hartman, 1992), and Surface Mining (Kennedy, 1990). Additionally, employees of IHC Merwede- and external experts were consulted to obtain expenditure details as accurately as possible. Figure 9-1 illustrates the structure of the model.

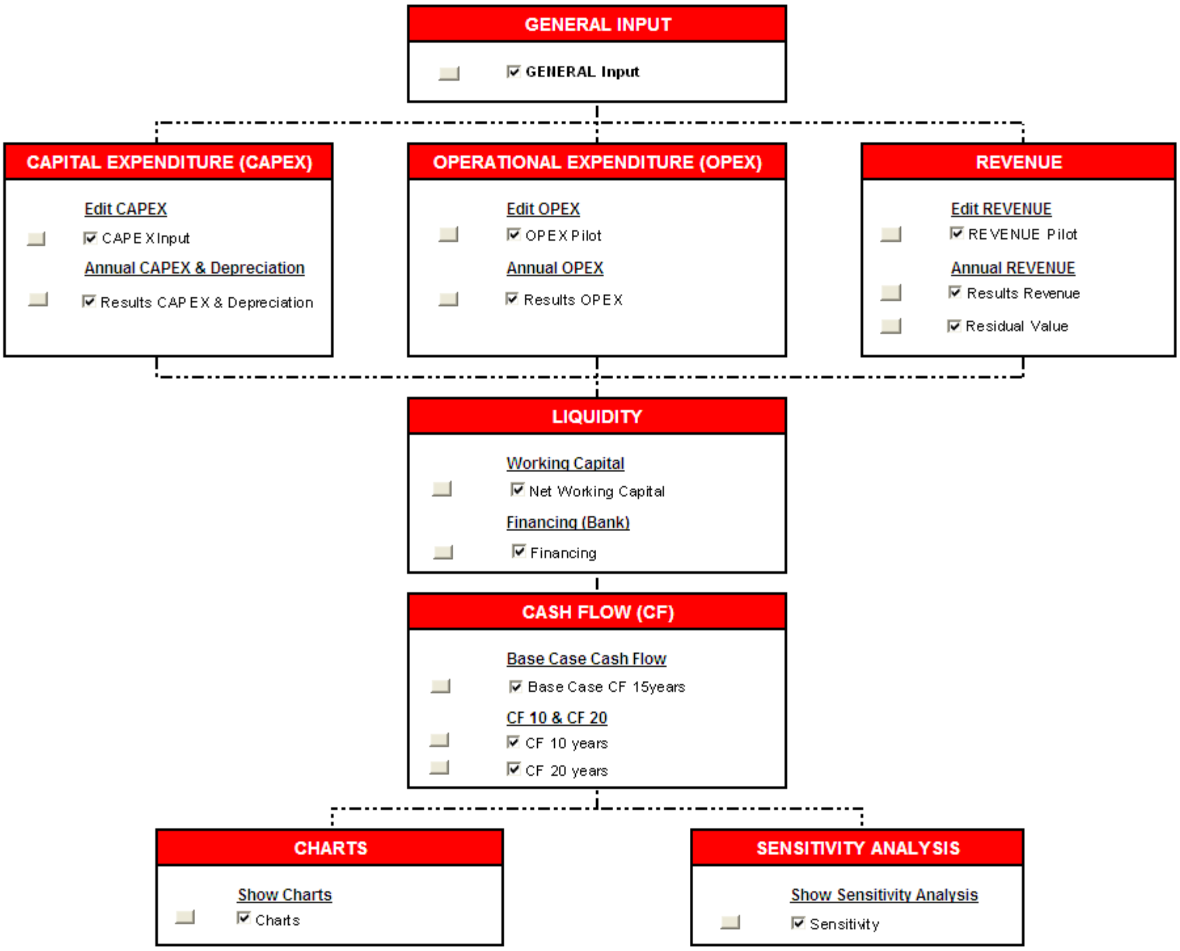


Figure 9-1 Structure Cash Flow Model (Lay-out / Menu tab)

9.1. Capital Costs

Capital expenditures (CAPEX) are those expenses made to acquire or develop capital assets, of which benefits will be derived over several years. The largest portion of CAPEX is incurred in the initial stages of the project, but some CAPEX are incurred annually throughout the life of the mine/operation. The CAPEX of the presented operation are based on equipment and infrastructural requirements for mining and processing. This includes all mining machinery, the surface support vessel with the processing plant, specific port, maintenance-, infrastructure, and ancillary requirements.

In this study the temporary storage facility (on- or offshore) of the receiving terminal (the port) is not considered in the expenditure estimate. The assumption is that an infrastructure exists to unload vessels and receive the natural gas adequately. Table 9-1 illustrates the required initial capital costs of the gas-hydrate deep-sea mining operation.

Table 9-1 Initial Capital Costs required at start of operation

Type:	Costs [million US$]
Mining	433
Processing Plant	625
Ancillary and Infrastructure	64
Total[a]	**1,122**

[a] Contingency of +/- 35% due to the great uncertainties

The total initially required capital outlay for the commissioning of this operation is US$ 1,122 million. The exploration of the deposit is sourced out, no CAPEX for exploration equipment are defined. The costs for maintenance equipment in workshops and vessel were set at US$ 3 million with an average working life of 2 years. Additionally a 10% contingency was estimated for items not included so far. With this the costs for the initial phase sums up to approximately US$ 112 million.

Pre-production
In the pre-production phase the capital costs are the equipment and facility costs. These costs include the mining lease and other facilities such as the re-gasification plant and office buildings and are reflected in the ancillary and infrastructure costs (Table 9-1).

Mining
The mining costs include all capital equipment as outlined in chapter 6. An overview of the costs is shown in Table 9-2.

Table 9-2 Costs of mining equipment

Type of Equipment	Costs [million US$]
Hydrate Recovery Tool (2 HRT + 1 spare)	17
Vertical Riser Mechanism	126
Mining Support Vessel	290
Total	**433**

Processing
The processing is subdivided into four steps as described in chapter 7:

- Primary separation (separate gas from solids and liquids)
- Gas treatment (gas treating, dehydration and storage)
- Solid and Liquid treatment (water handling, trace hydrocarbon removal, solid control, water treatment, disposal)
- CNG plant (with loading facilities including compressors, pipelines and buoys)

In Table 9-3 the costs for the different steps are given.

Table 9-3 Processing capital costs

Process	Costs [million US$]
Power plant, Controls & Instrumentation [a]	100
Primary Separation [a]	125
Gas treating [a]	110
Dehydration plant [a]	25
Water Handling plant & disposal system [a]	50
Solid Control [a]	25
Solids Discharge equipment [a]	50
Trace Hydrocarbon Removal plant [a]	25
CNG plant with offloading facilities [b]	40
Storage tank [a]	75
Total	**625**

[a] (Bluewater, et al., 2010); [b] (Economides, et al., 2006)

Ancillary and Infrastructure

Several infrastructure costs such as office buildings, workshops, and port facilities are not covered in the previous sub-sections. Ancillary costs originating from, e.g., communication systems and exploration leases also have to be paid for. The breakdown of ancillary and infrastructure costs is listed in Table 9-4.

Table 9-4 Ancillary and Infrastructure costs

Type	Costs [million US$]
Buildings	3.5
Communications	2.5
Port	50
Exploration- & Mining Lease	5
Ancillary Projects	3.1
Total	64.1

9.2. Operating Costs

In this work the operating expenditures (OPEX) are the expenses related to the production of natural gas. This section includes the OPEX estimation of labour- , fuel-, and lubricant costs. All these facets cover mining, processing, ancillary operations and maintenance costs. The transportation of natural gas is contracted out, whereby the price is the sum of operational costs as well as recovery of capital spent by the contractor and is given in US dollars per million British thermal unit (mmBtu). The annual operating costs were estimated at almost US$ 114 million, which equates US$ 3.54 per cubic metre of gas hydrate bearing sediments (GHBS). These costs (shown is Table 9-5) were based on the following items:

- Labour
- Fuels and Lubricants
- Transportation
- Ancillary

Table 9-5 Total Operating Costs of Gas Hydrate Project

OPEX	$/yr	$/m^3	Percentage
Management and Labour Costs	15,292,500	0.48	13.5%
Fuels and lubricants Costs	59,342,273	1.85	52.3%
Transportation Costs	35,027,283	1.09	30.9%
Ancillary Costs	3,731,739	0.12	3.3%
Total OPEX cost for Base Case	**113,393,795**	**3.54**	**100,0%**

Management and Labour Costs

The labour costs are estimated at US$ 15.3 million per year which equates to 0.48 US$/m^3 GHBS. These costs are the aggregate of management-, mining- and processing costs.

Fuels and lubricants

As shown in Table 9-5, the annual fuel and lubricant costs are approximately US$ 60 million, which equates to 1.85 US$/m^3 of GHBS.

Fuels

For the whole operation, power costs are fully related to fuel costs. For this project the engine capacity was set at 0.3 litres per hour per kilowatt (Noakes, et al., 1993). Hence the estimated fuel costs using the following equation:

$$C_f = P \times 0.3 \times FJF \times C_u \times h$$

Where:

Symbol	Description	Estimated	Unit
C_f	Fuel costs		US$
P	Engine capacity	43,550	kW
FJF	Fuel job factor	0.4 for mining	-
		0.4 for processing	-
C_u	Unit cost of fuel	0.56	US$/L
h	Hours	7680	hours

The fuel costs for mining include power requirements for mining, sailing and maintenance activities related to the mining equipment and mining support vessel. Power/fuel costs for mining were estimated at just over US$ 22.4 million per year, which is 0.70 US$/m^3 of GHBS.

The assumptions of the fuel costs of the processing are based on the 60,000 kW and are therefore estimated at US$ 30.8 million per year and 0.96 US$/m^3 of GHBS (Bluewater, et al., 2010).

Lubricants

The annual lubricant costs for the whole process are estimated at US$ 6.2 million or 0.19 US/m^3 GHBS. These costs are related to mining, processing and maintenance (Table 9-6).

Table 9-6 Lubricant costs

	US$/yr
Mining	4,250,000
Processing [a]	1,500,000
Maintenance	475,000

[a] (Bluewater, et al., 2010)

Transportation

The CNG-vessel is leased from a company like 'Enersea' and 'Sea NG'. The estimation of this type of transportation is 2.75 dollar per million British thermal unit (mmBtu), which equates 0.097 US$/m^3 of natural gas (Dunlop, 2010). With an annual production of 360 million cubic metre of gas the annual transportation cost are US$ 35 million. The owner of the vessel provides a transport service under a long term contract that includes both capital and operating costs.

Ancillary

The total annual ancillary operational costs were estimated at approximately US$ 3.73 million, which equates to US$ 0.12 per cubic metre of gas hydrate bearing sediments. These costs are based on 5 per cent of the labour-, fuel- and lubricant costs.

9.3. Revenue Estimation

The gas price and average gas yield of the gas hydrate bearing sediments and the recovery rates of mining and processing are input parameters to estimate the total gross revenue. The revenue per excavated cubic metre of valuable resources can be calculated as follows.

$$Revenue\ per\ m^3\ [US\$/m^3_{sediment}] = \frac{P_{gas}}{28{,}26[m^3/mmBtu]} \times \gamma_{gas} \times R_{mining} \times R_{processing} \approx\ 1.67\ US\$/m^3_{sediment}$$

Where:

Symbol	Description	Estimated	Unit
P_{gas}	Gas Price	4.2	US$/mmBtu
γ_{gas}	gas yield per m^3 sediments[a]	11.25	m^3/m^3
R_{mining}	Recovery rate mining	100	%
$R_{processing}$	Recovery rate processing	100	%

[a] Average grade which covers losses in mining and processing

The annual production of this project is estimated to 32 million m^3. This is calculated from:

$$Annual\ production[m^3] = d_{uptime} \times h_{effective} \times P_{insitu\ GHBS} \times HRT_{No.} = 32\ million\ m^3$$

Where:

Symbol	Description	Estimated	Unit
d_{uptime}	Annual operation uptime	320	Days
$h_{effective}$	Effective hours per day	20	Hours
$P_{insitu\ GHBS}$	Production insitu GHBS per HRT	2,500	m^3
$HRT_{No.}$	Number of Hydrate Recovery Tools	2	

By multiplying the revenue per cubic metre natural gas present in GHBS with the annual production in cubic metre of sediment the annual production revenue is obtained. Figure 9-2 shows the annual cumulative gas production and gross revenue for the life of the mine. The annual gross revenue for the operation in the base case is US$ 53.5 million.

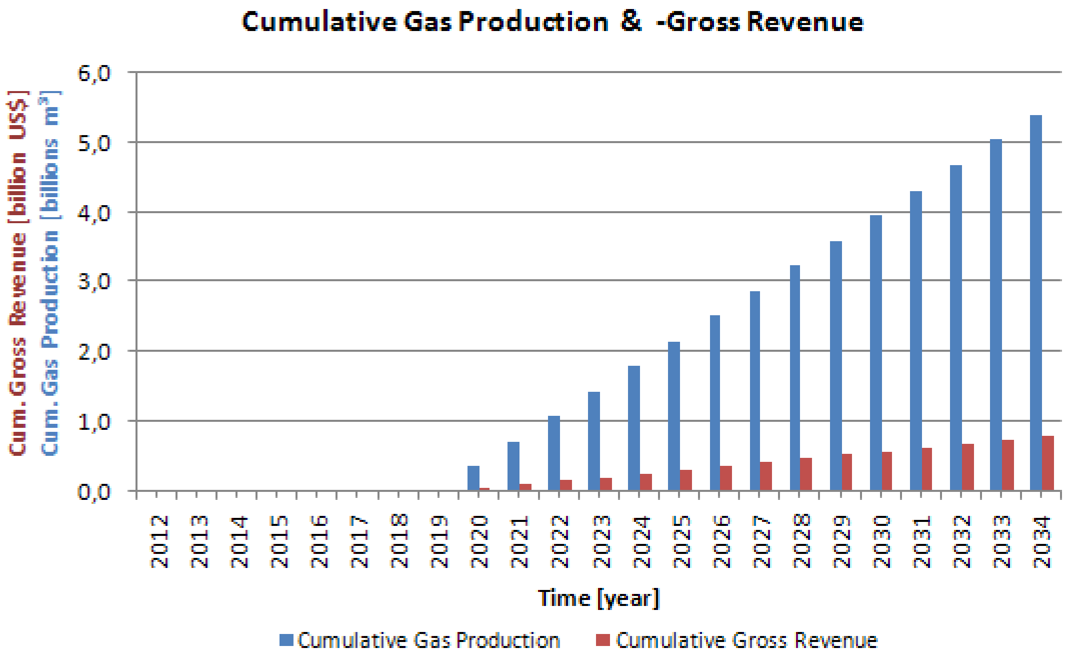


Figure 9-2 Cumulative Gas Production & -Gross Revenue

The royalty rate is subtracted from the production revenue and the residual value is added in the last production year. Residual value is another name for salvage value, which contains the remaining value of the total mining system after depreciation. Additional features are the overburden ratio and a maximum for the mineral resources. With the size of the Atwater Valley deposit, which is estimated to be 0.0565 km^3 (5.65 km^2 with a maximum extraction depth of 10m) the minimum required size of the deposit should be at least 8 times larger for a production period of 15 years.

9.4. Depreciation and Residual Value

Simply stated *depreciation* is the loss of value caused by the wear of equipment during the equipment's life span. For this operation a straight-line depreciation was assumed for all equipment. The *residual value* (or salvage value) contains the remaining value of the total mining system and is calculated for a 10, 15 and 20 year project lifetime.

9.5. Taxes

For this thesis it is not required to dilate upon taxes. Therefore a tax rate of 30% is assumed to be paid to the United States, covering all types of taxes that might be imposed.

9.6. Interest

The net interest is the net amount of interest payments and interest income. These are both included in the computation of the cash flow. The net interest is based on the average of one year's economic balance.

9.7. Working Capital

The net working capital equals current operating assets minus non-interest bearing current liabilities (defined as the sum of the operating cash, debtors and stocks). The outstanding receivables and inventories are expressed in days per year multiplied by the annual gross revenue. The outstanding payables are expressed in days per year multiplied by the annual operating expenditures.
For this project it was estimated to assume 60 days to gain receivables and 30 days for inventories. Payables are required to be paid after 45 days.

9.8. Cash Flow Model Results

This cash flow model presents the financial data of a gas hydrate mining project. It is important to take the following assumptions into account in order to judge the outcome.

Assumptions
Table 9-7 presents general- and additional restructuring assumptions for the cash flow calculations. The detailed assumptions for CAPEX and OPEX are listed in Appendix G.

Table 9-7 Assumptions for the cash flow calculations

General input:			Revenue input:		
Start of production	2020	yr	Gas yield per m^3 sediment	11.25	m^3/m^3
			Mining Recovery	100	%
Tax rate over income	30	%	Processing Plant Recovery	100	%
NPV discount rate	15	%	Royalty	3	%
Annual growth rate	0	%	$V_{overburden}/V_{bulk}$ Ratio	0	%
Interest rate	5	%	Hydrate Recovery Tool	2	
			Production in-situ GHBS per Hydrate Recovery Tool	2,500	m^3/h
OPEX:					
Annual OPEX	113,393,795	$	Mineral Resources (max. 10m mining depth)	0.0565	km^3
			Amount of mineral resources	7.93	times
CAPEX:			**Annual Operation uptime:**		
Initial CAPEX	1,121,700,000	$		320	Days
				24	Hours
				2	Shifts
			Effective Hours per shift	10	Hours

Constraints
The cash flow calculation recognises certain constraints on the input and output.

Constraints on input:

- The revenue data are generated to describe the results for gas hydrate projects. However with a few adjustments, this model can be applied to other deep-sea mining projects.

Constraints on output:

- The output of the permitting and pre-production phase is fixed at eight and two years respectively before start-up.
- Straight-line depreciation over the equipment's life span.
- The life of mine/operation is fixed at 10, 15 and 20 years.

Results of Model

Appendix H lists the results of the OPEX, CAPEX, depreciation, residual value, gross revenue, interest, working capital and final cash flow of 10, 15 and 20 years lifespan. Note for a better understanding and correct interpretation of the outcome of the model the use of the excel workbook is strongly recommended. The results of the base case are shown in Appendix H.

9.9. Cash Flow Overview

Gas price of 4.2 US$/mmBtu (Base Case of 15 years)

The graph in Figure 9-3 shows the yearly cash in- and outflow with a gas price of 4.2 US$/mmBtu (12th of May 2010). This figure clearly presents that the company would not generate enough cash to meet its expenses at this gas price. Simply put, cash outflow is greater than cash inflow.

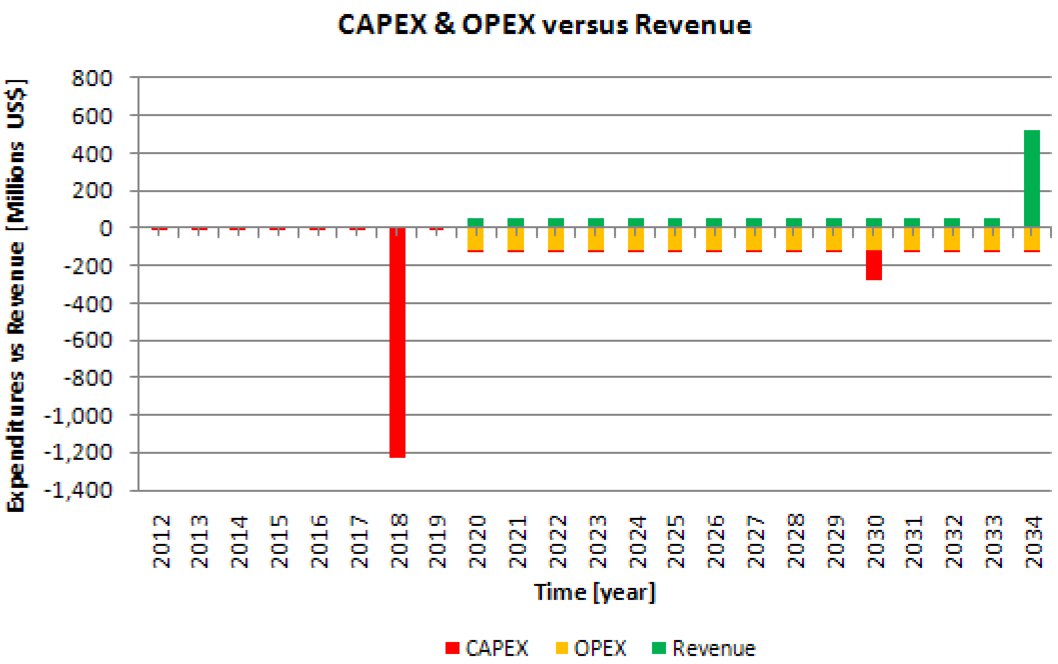


Figure 9-3 Cash flow Overview with gas price of 4.2 US$/mmBtu

Figure 9-4 shows the net cash flow (annually discounted) and the cumulative cash flow. The blue line shows a negative cumulative net cash flow of approximately US$ 3.80 billion after 15 years.

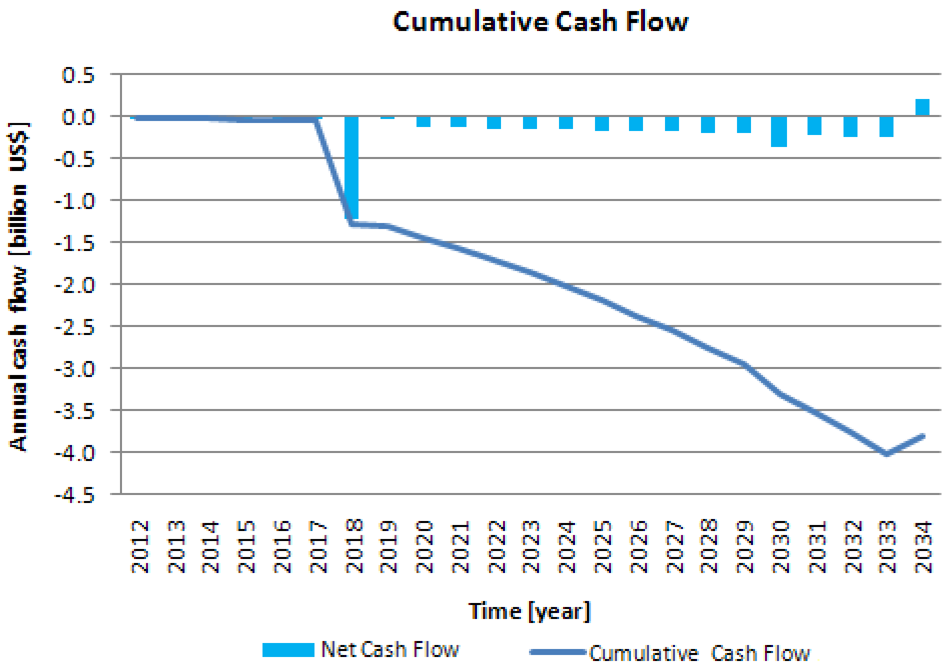


Figure 9-4 Cumulative Cash Flow with gas price of 4.2 US$/mmBtu

Gas price of 15 US$/mmBtu

In the winter of 2005 the gas price was around 15 US$/mmBtu(Aeberman, 2010). Even with this price there will be no payback period (shown in Figure 9-5). The analysis shows that even at this gas price the capital expenses could not be recovered.

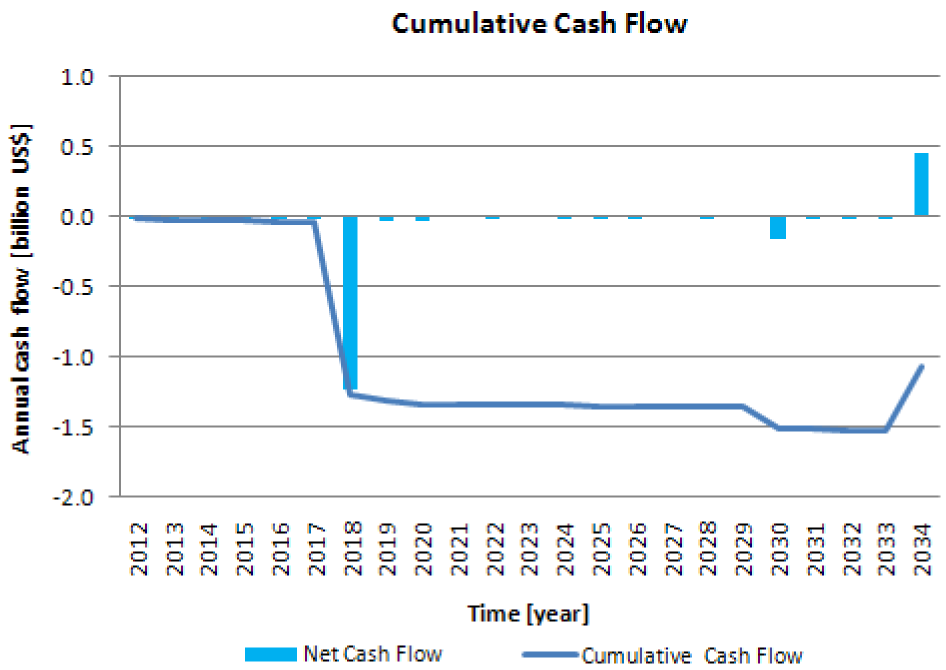


Figure 9-5 Cumulative Cash Flow with gas price of 15 US$/mmBtu

Required gas price

To determine the economic viability, the rate of return of the discounted cash flow or internal rate of return (IRR) is the key factor. A typical commercial mining project should at least have an IRR of 15% (Millar, 2008). The IRR is the discount rate that results in a Net Present Value (NPV) of zero for a series of future cash flows. A NPV of zero means the investment would neither gain nor lose value for the firm. To accommodate 15% IRR the gas price should become at least 40.05 US$/mmBtu. This is almost 10 times the gas price on Wednesday 12th of May 2010. Figure 9-6 illustrates the cumulative cash flow with a gas price of 40.05US$/mmBtu. This figure also shows that the payback period is reached in the year 2025, five years after the project starts. The payback period is defined as the minimum period of time theoretically necessary to recover the original investment.

Generally one barrel of oil is the amount of fuel that equals a British thermal unit (Btu) content of 5.8 million (IRS, 1999). With a gas price of 40.05 US$/mmBtu the equivalent is US$ 232 per barrel, while the oil price is US$ 76.22 per barrel on Wednesday 12th of May 2010 (Bloomberg, 2010).

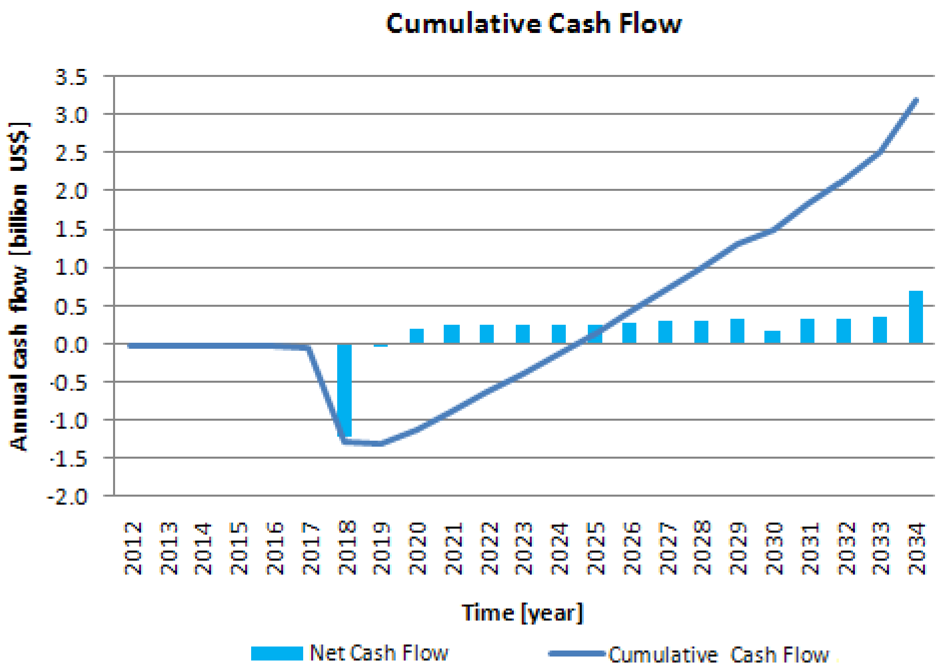


Figure 9-6 Cumulative Cash Flow with required gas price of 40.05 US$/mmBtu

9.10. Sensitivity Analysis

Based on the results of a sensitivity analysis it can be estimated how much the original analysis would change due to changes in the input data. It helps to evaluate the operations profitability and economic viability given changes in gas price, gas yield, interest, corporate tax, operational- and capital expenditures. The effect on the NPV due to changes of these parameters is shown in Figure 9-7.

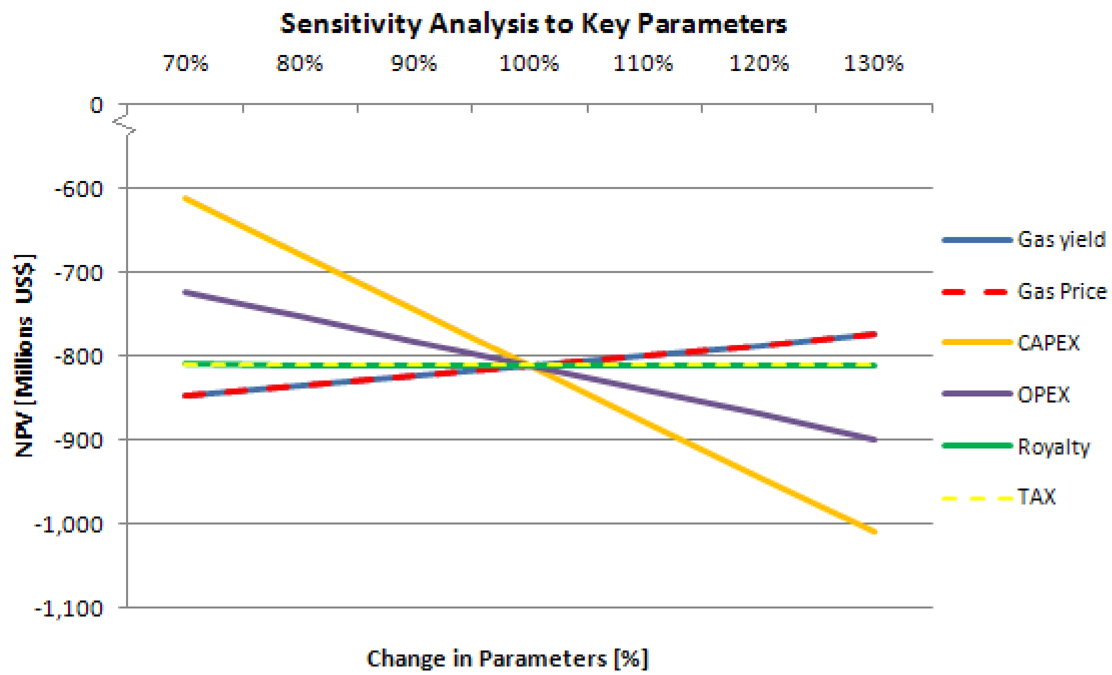


Figure 9-7 Net Present Value (@ 15%) Sensitivity Analysis to key parameters (gas @ US$ 4.2 / mmBtu)

As could be expected the recovery of natural gas from gas hydrate bearing layers is very capital expensive. The spider plot (Figure 9-7) shows that the capital expenses are the key parameter. Even a change of CAPEX by 30 per cent is not enough to bring the NPV to zero.
The plot also identifies that relative changes in the operating costs has a greater impact on the viability of the project than the gas yield and the gas price. Within the base case the corporate tax remains zero, due to the negative annual net income before tax (EBIT) throughout the life of the mine.

10. Conclusions and Recommendations

10.1. Conclusions

The following conclusions can be drawn with respect to natural gas hydrate (NGH) deposits:

- NGH exist globally but occur predominantly around the edge of the continents and in marginal marine basins, like the Gulf of Mexico and in some permafrost regions. The locations of all marine gas hydrate deposits are within the Economic Exclusive Zones of countries.
- The estimated volume of NGH with respect to energy contains twice the amount of currently recoverable world-wide fossil fuels.
- The occurrence of hydrates depends on the temperature and pressure on the seafloor and the kind of gas included.
- Depressurization, thermal- and chemical stimulation are three possible dissociation mechanisms for the production of hydrocarbon gases from NGH.

To answer the main research question: *'Is deep sea mining of gas hydrates from seafloor and sediments feasible from a **technological** perspective?'*:

- Technologically it seems to be possible to extract natural gas from gas hydrate bearing sediments (GHBS).
- The geological data available on GHBS of the Atwater Valley or other gas hydrate deposits strongly supports further investigation into the feasibility of a potential mining operation.
- It seems feasible to design and construct a mining system operated from a vessel. Thereby the combination of various existing technologies required for the gas production from GHBS is new and needs more research.
- The maximum production rate depends on the available equipment and expertise of the workforce. Therefore more research is necessary to develop a method to make a more realistic estimation of these values.
- At the moment there are no plants to process GHBS. However, several technologies are available to remove liquids and solids from gases.
- Compressed Natural Gas seems to be the best way to transport gas from the mining site to its market.

To answer the main research question *'Is deep sea mining of gas hydrates from seafloor and sediments feasible from an **economic** perspective?'*:

- Based on the results from the economic analysis of the base case, extraction of marine gas hydrates has currently no economic perspective. This is caused mainly by the high Operating- and Capital Expenditures. Especially the CAPEX on the start of the operation is high.
- Estimated revenues are considerable, however they are based on assumptions needed to be verified or more accurately detailed.

- Due to the relative long pre-production period, the negative cash flow is considerable and thus a high risk. Especially as the net cash flow stays negative during the whole production period.
- The sensitivity analysis shows that even after changes of the input values of the key parameters the net present value remains negative.
- To make the mining economically attractive, the required gas price has to be ten times the current gas price of 4.2 US$/mmBtu.
- The Atwater Valley is a sub-economic NGH resource. Based on the current market condition, production is not economically valid. But the production might become economically justified if the projected feasible market condition and/or the conditions for the investment environment improve.

10.2. Recommendations

Although this mining project is currently not economically feasible with the applied data it is a good exercise to provide insight and to identify the need to gather necessary information. It illustrates where more research and study is needed to evaluate comparable operations in the future:

- Geotechnical properties (i.e. compressive-; tensile-; and cohesive strength) of gas hydrate bearing sediments to optimise design of mining and processing and thus reduce CAPEX and OPEX.
- The behaviour of natural gas hydrates during the whole production process, including the chemical and physical stability of the compounds is needed to define a safe and reliable operation; in particular
    - During the cutting of GHBS. Thereby, the impact (i.e. vibration, water flows) on GHBS should be looked at in the vicinity of the mining equipment.
    - During the vertical transportation of the slurry (50% GHBS and 50% seawater) in the riser and the centrifugal pumps.
    - During the processing of GHBS.
- The intensity and the impact of marine mining on different environmental parameters as well as evaluating the processes of restoration and revitalising of the deep sea environment and animal communities. It is a must to have that knowledge to gain public support and permit approvals.
- Whether NGH deposits exist with enough reserves.
    - Higher gas yield of GHBS
    - Area of NGH resources on the sea floor.
- Scientific innovations whereby the conventional technique is replaced by a breakthrough technology.
    - For instance a primary separation at the seabed, either with physical (local pressure and temperature) or chemical methods.
- Careful monitoring of global supply and demand of fossil fuel sources, which may lead to feasible exploitation of GHBS.
- Team up with oil and gas companies that are familiar with mining and processing of natural gas.

Based on the experience using the cash flow model, it is recommended to:

- Optimise the cash flow model, for instance by incorporating the possibility to change:
  - The production life time
  - The years of the permitting- and pre-production phase before start-up.
- Improving and adjusting the model so that it can be applied for other deep see mining operations. This should help minimising uncertainties on economic viability of NGH- or other deep sea mining operations.

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A. Mine Planning Process

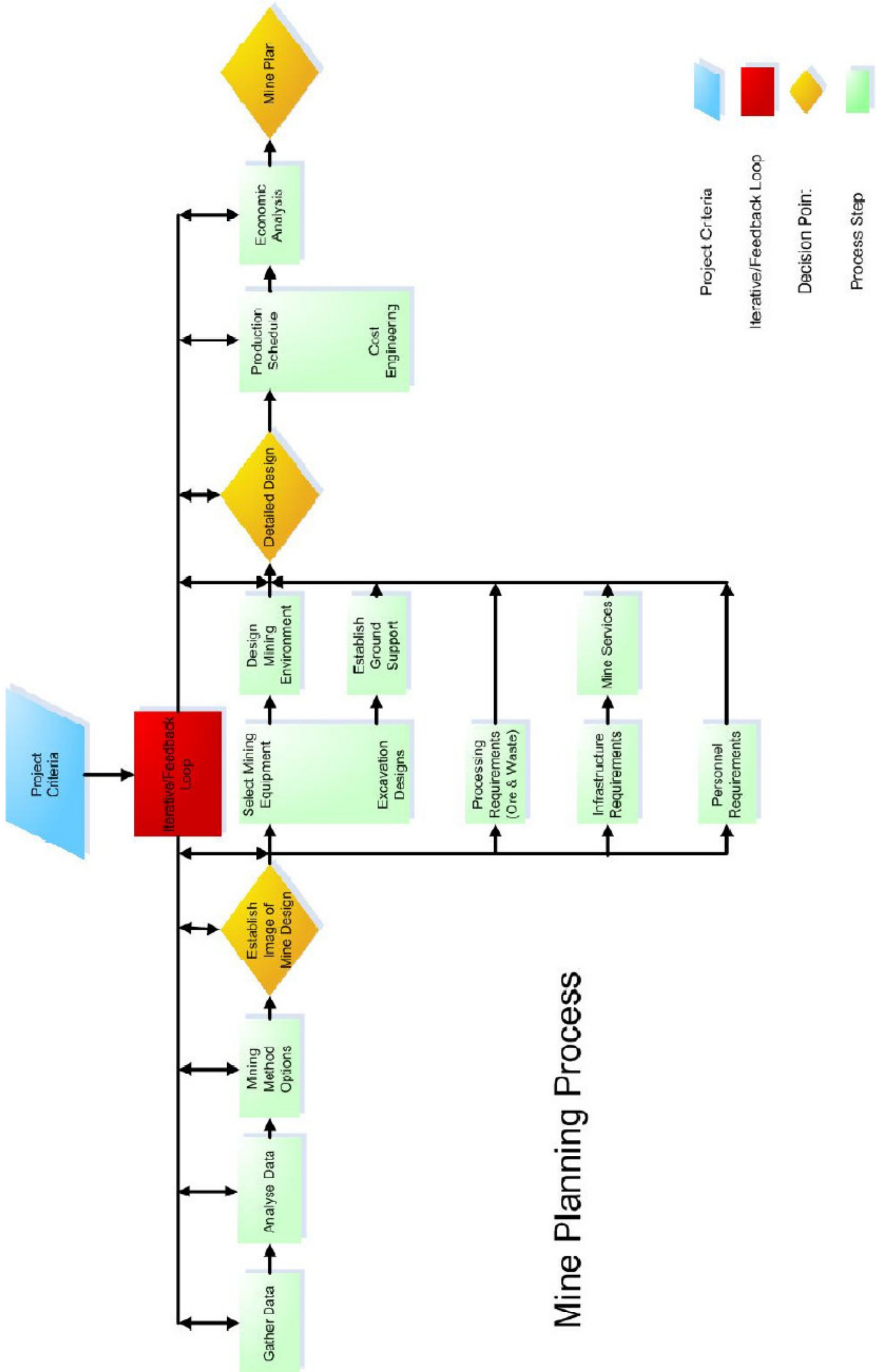

Figure A-1 Mine Planning Process (Slagmolen, 2009)

B. Hydrate Crystal Cell Structures

An overview of the Crystal properties of sI, sII, and sH.

Table B-1 Hydrate Crystal Cell Structures (Sloan, et al., 2008)

Structure	**I**		**II**		**H**	
Crystal system	Cubic		Cubic		Hexagonal	
Space group	Pm3n (No. 223)[c]		Fd3m (No. 227)[c]		P6/mmm (No. 191)[c]	
Lattice description	Primitive		Face centered		Hexagonal	
Lattice parameters[a]	$a = 12$ Å $\alpha = \beta = \gamma = 90°$		$a = 17.3$ Å $\alpha = \beta = \gamma = 90°$		$a = 12.2$ Å $c = 10.1$ Å $\alpha = \beta = 90°, \gamma = 120°$	
Ideal unit cell formula	$6(5^{12}6^2) \cdot 2(5^{12}) \cdot 46H_2O$		$8(5^{12}6^4) \cdot 16(5^{12}) \cdot 136H_2O$		$1(5^{12}6^8)$ $3(5^{12}) \cdot 2(4^3 5^6 6^3) \cdot 34H_2O$	
Number of faces[b]: hexagonal (H), pentagonal (P), square (S)	H = 6 P = 48		H = 16 P = 144		H = 7 P = 30 S = 3	
Atomic positions: number and symmetry	$5^{12}6^2$ (d) 5^{12} (a)	6, $\bar{4}$ 2 m 2, m3	$5^{12}6^4$ (b) 5^{12} (c)	8, $\bar{4}$ 3 m 16, $\bar{3}$ m	$5^{12}6^8$ 5^{12} (g) $4^3 5^6 6^3$	1, 6/mmm 3, mmm 2, $\bar{6}$ m2
	O (c) O (i) O (k)	6, $\bar{4}$ 2 m 16, 3 m 24, m	O (a) O (e) O (g)	8, $\bar{4}$ 3 m 32, 3 m 96, m	O (o), O (h) O (n) O (m)	12, m 4, 3 m 12, m 6, mm2
	(1/2 H) (i) 3(1/2 H) (k) 2(1/2 H) (l)	16, 3 24, m 48, 1	2(1/2 H) (e) 3(1/2 H) (g) (1/2 H) (i)	32, 3 m 96, m 192, m	X(1/2 H) X(1/2 H) X(1/2 H)	

[a] Lattice parameters are a function of temperature, pressure, and guest composition. Values given are typical average values.
[b] Number of faces accounting for face-sharing in the unit cell.
[c] Space group reference numbers from the International Tables for Crystallography.

Atomic positions indicate the Wyckoff letter in parentheses.

Table modified from Jeffrey (1984, p. 150).

C. Commodity prices natural gas

An overview of the natural gas prices in May 2010.

Figure C-1 Natural gas January 2009 - May 2010 [US$ / mmBtu](tradingeconomics, 2010)

An overview of the natural gas prices in graphs for 1, 3 and 10 years in December 2009. Natural Gas Futures Trading - Chart with Historical Prices (www.tradingeconomics.com).

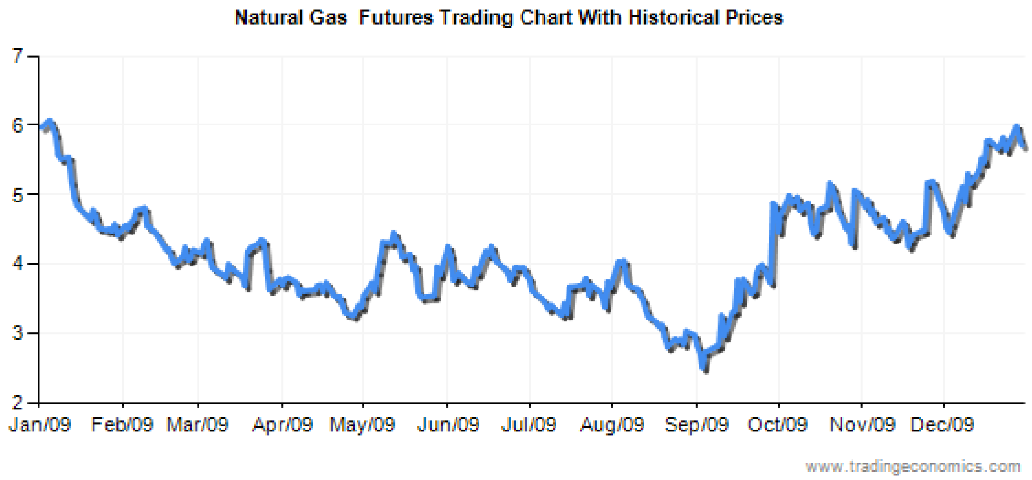

Figure C-2 Natural gas 1 year prices from December 2009 [$ / mmBtu] (tradingeconomics, 2010).

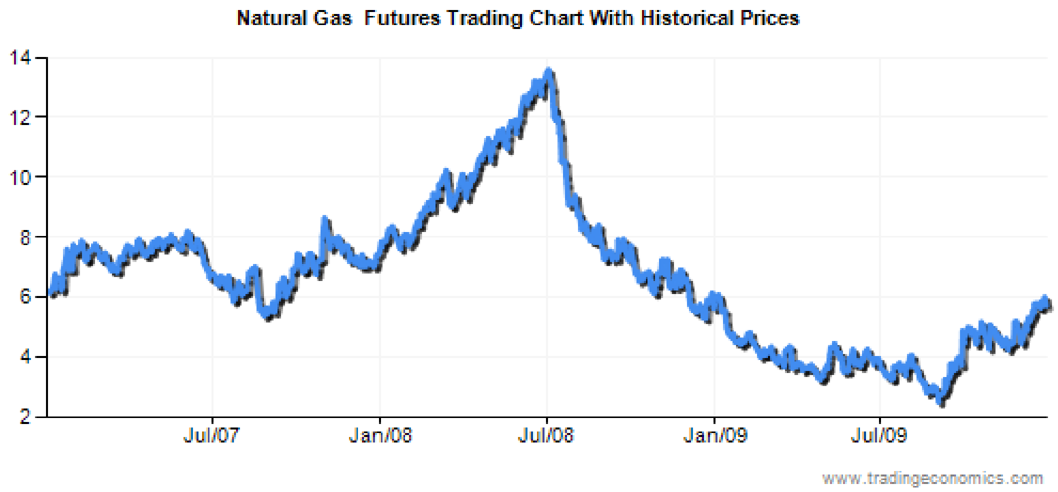

Figure C-3 Natural gas 3 year prices from December 2009 [$ / mmBtu] (tradingeconomics, 2010).

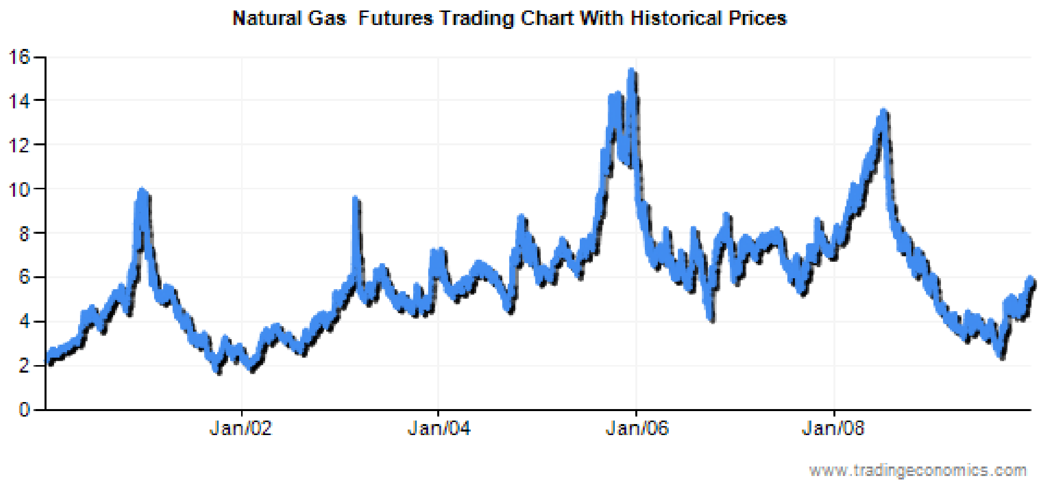

Figure C-4 Natural gas 10 year prices from December 2009 [$ / mmBtu] (tradingeconomics, 2010).

D. Workforce Requirements

Table D-1 Workforce for gas hydrate mining system

Management and labour for gas hydrate mining system			
General	number	$/y each	Total $/y
MANAGEMENT:	5		465.000
General Manager	1	200.000	200.000
Secretary	2	60.000	120.000
Chief accountant	1	75.000	75.000
Accountant	1	70.000	70.000
MINING	76		8.050.000
Sailing			*3.470.000*
Captain	2	200.000	400.000
Chief Officer	2	125.000	250.000
2nd Officer	3	100.000	300.000
Boatswain	3	100.000	300.000
Able Seaman	6	95.000	570.000
Ordinary Seaman	3	85.000	255.000
Chief Engineer	2	150.000	300.000
Assistant Engineer	3	100.000	300.000
Mechanic	3	95.000	285.000
Oiler	3	85.000	255.000
Greaser	3	85.000	255.000
Mining			*3.500.000*
Chief Engineer	2	150.000	300.000
Mining Engineer	2	110.000	220.000
Surveyor	2	100.000	200.000
Geologist	2	100.000	200.000
Foreman	2	150.000	300.000
Operator HRT (TRIPOD)	6	95.000	570.000
Operator Crane	6	95.000	570.000
Operator Cusher	6	95.000	570.000
Operator VRM	6	95.000	570.000
Maintenance			*1.080.000*
Master Mechanic	3	120.000	360.000
Mechanic	3	120.000	360.000
Electrician	3	120.000	360.000
PROCESSING	76		4.907.500
Process Superintendent	2	120.000	240.000
Maintenance Foreman	4	95.000	380.000
Process Foreman	4	87.500	350.000
Plant Foreman	4	80.000	320.000
Senior Petroleum Engineer	1	100.000	100.000
Petroleum Engineer	1	87.500	87.500
Control Room Operator	8	70.000	560.000
Process Technican	4	70.000	280.000
Instrument Technican	4	67.500	270.000
Mechanic	4	60.000	240.000
Electrician	4	60.000	240.000
Primary Separation Operator	4	55.000	220.000
Gas Treating Operator	4	55.000	220.000
Gas Dehydration Operator	4	55.000	220.000
Water Handling Operator	4	55.000	220.000
Hydrocarbon Removal Operato	4	55.000	220.000
Solid Control and Water storage Operator	4	55.000	220.000
Assayer	4	45.000	180.000
Sampler	4	45.000	180.000
Laborer	4	40.000	160.000
ANCILLARY	23		1.870.000
Cook	2	80.000	160.000
Janitor	3	85.000	255.000
Helper	12	80.000	960.000
Geo Sampler	3	85.000	255.000
Medic	3	80.000	240.000
Total yearly Management and Labour Costs for gas hydrate mining	**180**		**15.292.500 $/yr**
Total Management and Labour Cost per m³ of sediment for hydrate mining based on:	**32.000.000 m³/yr**		**0,48 $/m³**

E. Seastate

SEA STATE	SEA DESCRIPTION	COMMENT	WIND FORCE	WIND DESCRIPTION	WIND SPEED RANGE						WIND SPEED	WAVE HEIGHT						SIGNIFICANT RANGE OF PERIODS		AVERAGE PERIOD	AVERAGE W/LENGTH		Period Max Energy Spectrum	Min Fetch	Min Duration
					MIN Knots	MAX Knots	MIN Km/hr	MAX Km/hr	MIN mph	MAX mph	Knots	SIGNIFICANT Feet	SIGNIFICANT Metres	AVERAGE Feet	AVERAGE Metres	AVE 1/10th HIGH Feet	AVE 1/10th HIGH Metres	MIN Secs	MAX Secs	Secs	Feet	Metres	Seconds	Naut Miles	Hours
0	(GLASSY)		0	CALM	0	0,99	0	1,8	0	1,1	0	0	0	0	0	0	0	-	-	-	-	-	-	-	-
1	CALM (RIPPLED)		1	LIGHT	1	3	1,9	5,6	1,2	3,5	2	0,08	0,02	0,05	0,02	0,1	0,03	0,1	1,2	0,5	0,8	0,25	0,7	5	0,3
		Nominal	2	BREEZE	4	6	7,4	11,1	4,6	6,9	5	0,29	0,09	0,18	0,05	0,37	0,11	0,4	2,8	1,4	6,7	2,04	2	8	0,7
2	SMOOTH (WAVELETS)		3	GENTLE BREEZE	7	10	13	18,5	8,1	11,5	8,5	1	0,3	0,6	0,18	1,2	0,37	0,3	5	2,4	20	6,1	3,4	9,8	1,7
		Nominal									10	1,4	0,43	0,88	0,27	1,8	0,55	1	6	2,9	27	8,23	4	10	2,4
			4	MODERATE BREEZE	11	16	20,4	29,6	12,7	18,4	12	2,2	0,67	1,4	0,43	2,8	0,85	1	7	3,4	40	12,19	4,8	18	3,8
3	SLIGHT										13,5	2,9	0,88	1,8	0,55	3,7	1,13	1,4	7,6	3,9	52	15,85	5,4	24	4,8
		Nominal									14	3,3	1,01	2	0,61	4,2	1,28	1,5	7,8	4	59	17,98	5,6	23	5,2
											16	4,6	1,4	2,9	0,88	5,8	1,77	2	8,8	4,6	71	21,64	6,5	40	6,6
			5	FRESH BREEZE	17	21	31,5	38,9	19,6	24,2	18	6,1	1,86	3,8	1,16	7,8	2,38	2,5	10	5,1	90	27,43	7,2	55	8,3
4	MODERATE										19	6,9	2,1	4,3	1,31	8,7	2,65	2,8	10,6	5,4	99	30,18	7,7	65	9,2
		Nominal									20	8	2,44	5	1,52	10	3,05	3	11,1	5,7	111	33,83	8,1	75	10
			6	STRONG BREEZE	22	27	40,7	50	25,3	31,1	22	10	3,05	6,4	1,95	13	3,96	3,4	12,2	6,3	134	40,84	8,9	100	12
5	ROUGH										24	12	3,66	7,9	2,41	16	4,88	3,7	13,5	6,8	160	48,77	9,7	130	14
											24,5	13	3,96	8,2	2,5	17	5,18	3,8	13,6	7	164	49,99	9,9	140	15
		Nominal									26	15	4,57	9,6	2,93	20	6,1	4	14,5	7,4	133	40,54	10,5	130	17
			7	NEAR GALE	28	33	51,9	61,1	32,2	38	28	13	3,96	11	3,35	23	7,01	4,5	15,5	7,9	212	64,62	11,3	230	20
6	VERY ROUGH										30	22	6,71	14	4,27	28	8,53	4,7	16,7	8,6	250	76,2	12,1	280	23
		Nominal									30,5	23	7,01	14	4,27	29	8,84	4,8	17	8,7	253	77,11	12,4	290	24
											32	26	7,92	16	4,88	33	10,06	5	17,5	9,1	285	86,87	12,9	340	27
7	HIGH		8	GALE	34	40	63	74,1	39,1	46	34	30	9,14	19	5,79	33	10,06	5,5	18,5	9,7	322	98,15	13,6	420	30
											36	35	10,67	21	6,4	44	13,41	5,8	19,7	10,3	363	110,64	14,5	500	34
		Nominal									37	37	11,28	23	7,01	46,7	14,23	6	20,5	10,5	376	114,6	14,9	533	37
											38	40	12,19	25	7,62	50	15,24	6,2	20,5	10,7	392	119,48	15,4	600	33
8	VERY HIGH										40	45	13,72	28	8,53	58	17,68	6,5	21,7	11,4	444	135,33	16,1	710	42
		Nominal	9	STRONG GALE	41	47	75,9	87	47,2	54,1	42	50	15,24	31	9,45	64	19,51	7	23	12	492	149,96	17	830	47
											44	58	17,68	36	10,97	73	22,25	7	24	12,5	534	162,76	17,7	900	52
											46	64	19,51	40	12,19	81	24,69	7	25	13,1	590	179,83	18,5	1110	57
			10	STORM	48	55	88,9	101,9	55,2	63,3	48	71	21,64	44	13,41	90	27,43	7,5	26	13,8	650	198,12	19,4	1250	63
											50	73	22,25	49	14,94	99	30,18	7,5	27	14,3	700	213,36	20,2	1420	69
9	PHENOMENAL										51,1	83	25,3	52	15,85	106	32,31	8	28	14,7	736	224,33	20,8	1560	73
		Nominal									52	87	26,52	54	16,46	110	33,53	8	23,5	14,8	750	228,6	21	1610	75
											54	95	28,96	59	17,98	121	36,88	8	29,5	15,4	810	246,89	21,8	1800	81
			11	VIOLENT STORM	56	63	103,7	116,7	64,4	72,5	56	103	31,39	64	19,51	130	39,62	8,5	31	16,3	910	277,37	22,6	2100	83
											59,5	116	35,36	73	22,25	143	43,59	10	32	17	935	284,99	24	2500	101
			12	E	64	71	118,5	131,5	73,6	81,7	61	128	39,01	80	24,38	164	49,99	10	35	-	-	-	26	-	-

This data has been collated from various public information sources and is presented here in good faith. admin@seathree.demon.co.uk HOME

Figure E-1 Overview Seastate

F. Functional Decomposition of Mining System

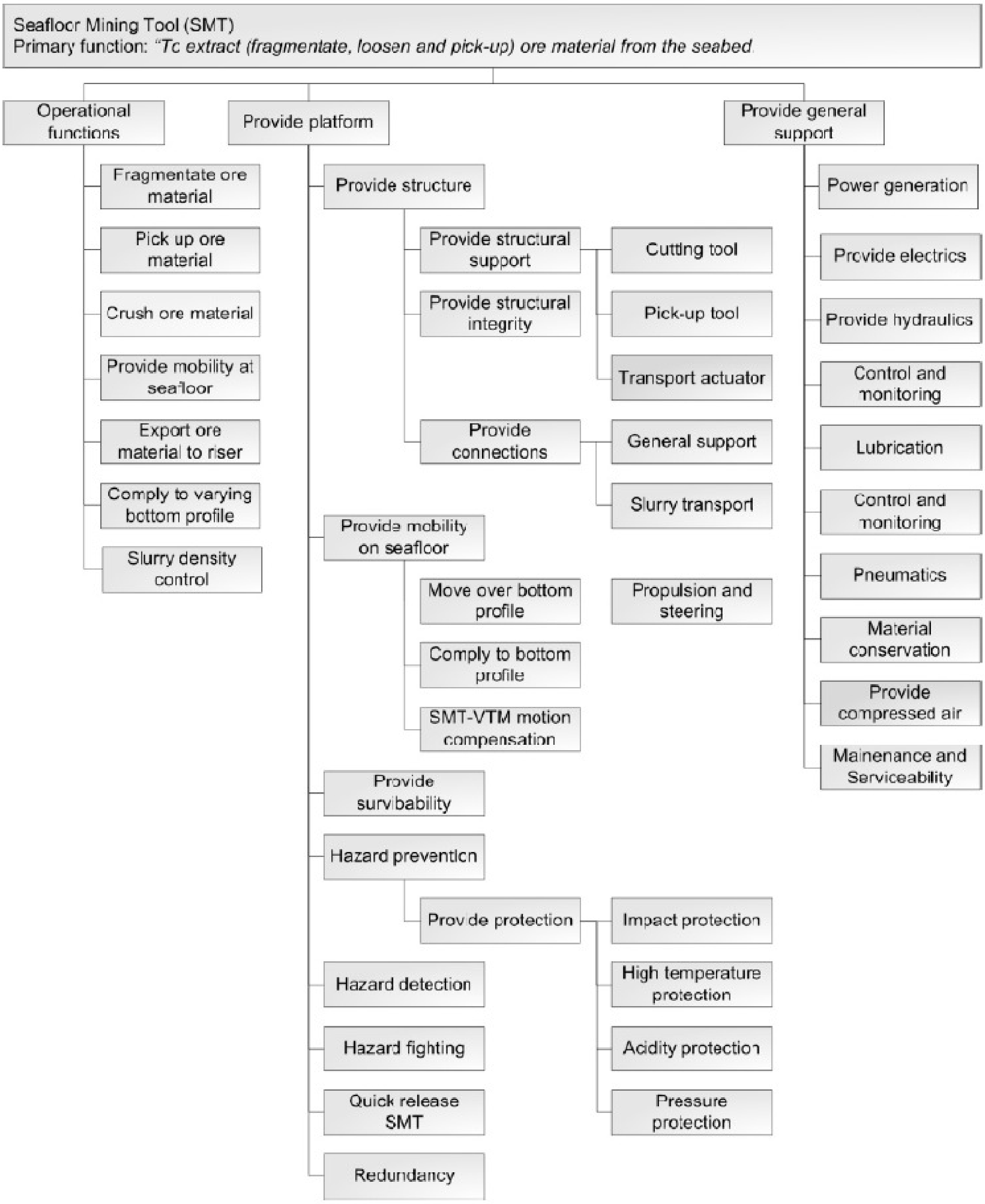

Figure F-1 Functional decomposition of Seafloor Mining Tool (van der Kooi, 2008)

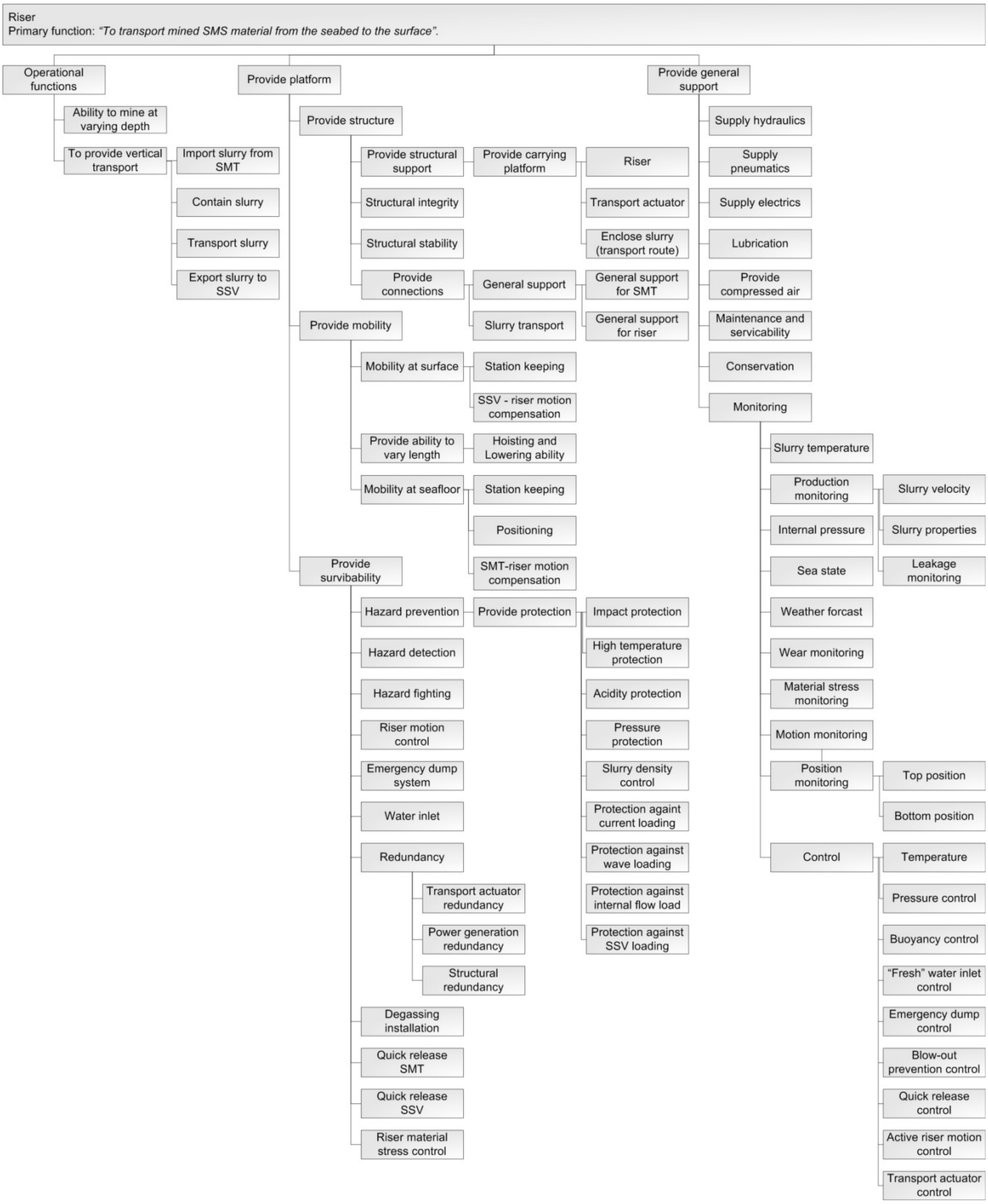

Figure F-2 Functional decomposition of Vertical Transport Mechanism (van der Kooi, 2008)

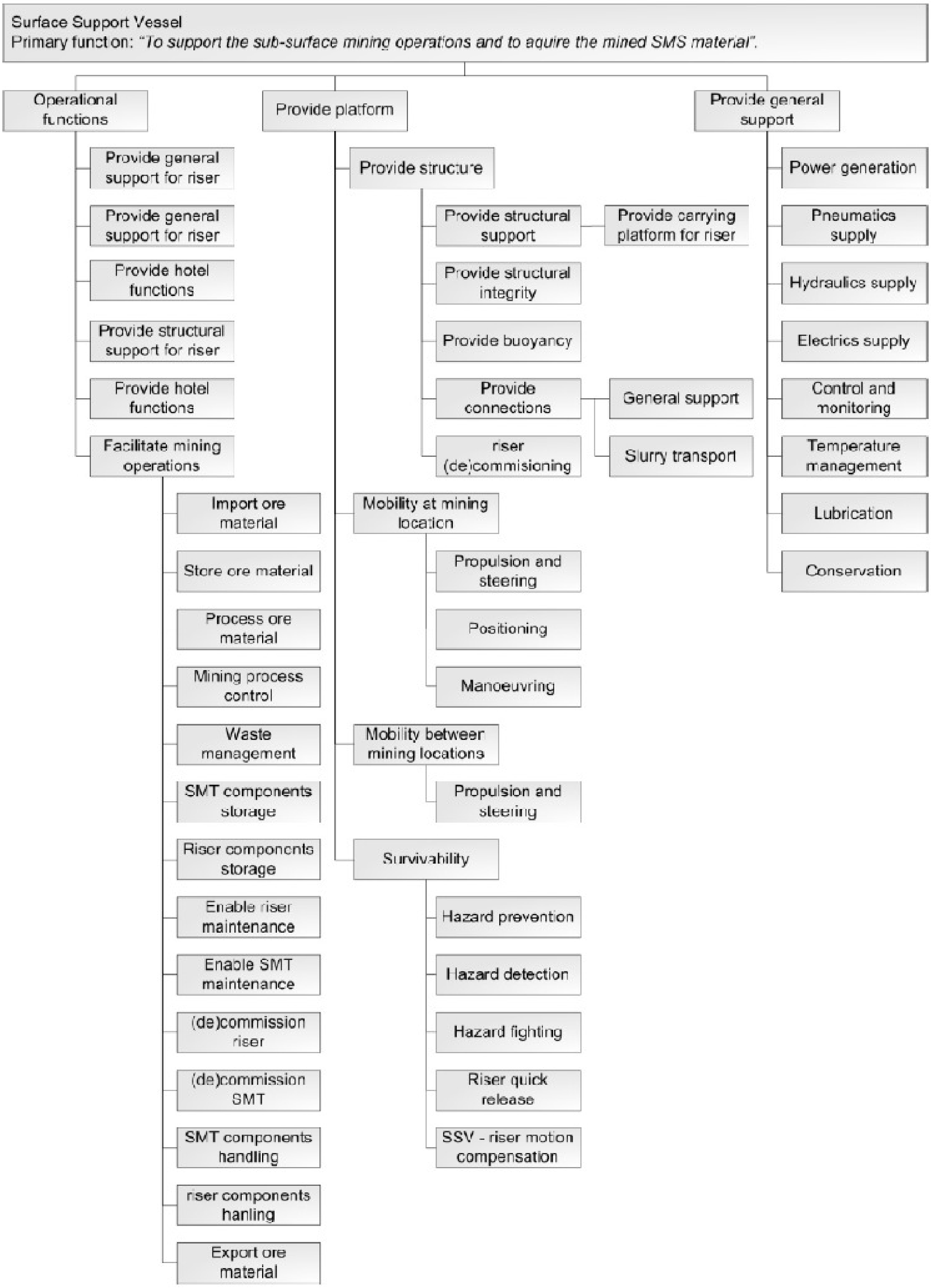

Figure F-3 Functional Decomposition of Surface Support Vessel (van der Kooi, 2008)

G. Assumptions for Cash Flow

Operational Expenditures Overview

Management and Labour costs are shown in Table D-1.
Fuel-, lubricants-, transportation- and ancillary costs are listed in Table G-1

Table G-1 Fuel-, lubricants-, transportation- and ancillary costs

Operational costs fuel and lubricants for Deep Sea Mining System

Price Marine Diesel Oil (MDO) per metric tonne:	632,5 US$/metric tonne						
Price diesel per liter:						0,56	$/L
FUEL:	kW installed	Hours	Consumption Rate [L/h/kW]	Fuel Job Factor	Price per litre	Total cost in $	
Total fuel bill for operation with Deep Sea Mining System:						43.833.947	$
MINING	25.550	7.680	0,30	0,40	0,56	13.106.193	
	US$/hr	Hours				Total cost in $	
PROCESSING	4007,52	7.680				30.777.754	
LUBRICANTS:							
Total lubricants:						6.225.000	$
Mining						4.250.000	
Processing						1.500.000	
Maintenance						475.000	
Total yearly fuel and lubricants Costs for Deep Sea Mining System						**50.108.947**	**$/yr**
Total fuel and lubricants Costs per m3 for Deep Sea Mining System based on:			**32.000.000 m³/yr**			**1,57**	**$/m³**

Transportation - CNG carrier

	Annual gas production of		360.000.000	m³/yr
	Annual Production [MMBTU]	US$/MMBTU	Total $/y	
Transportation costs	12.737.194	2,75	35.027.283	
Total yearly Transportation Cost - CNG transportation - for gas hydrate mining			**35.027.283**	**$/yr**
Total Transportation Costs per m³ for gas hydrate mining based on:	**32.000.000 m³/yr**		**1,09**	**$/m³**

Ancillary

		Total $/y	
Labour @ 5%		784.625	
fuel and lubricants @ 5%		2.505.447	
Total annual Ancillary Costs		**3.270.072**	**$/yr**
Total Ancillary Costs per m3 for gas hydrate mining based on:	**32.000.000 m³/yr**	**0,10**	**$/m³**

Capital Expenditures overview with 2 Hydrate Recovery Tools

Table G-2 Overview Capital Expenditures

General	Component	Equipment	Quantity	Life [yr]	Cost Unit [US$]
MINING					
Mining	HRT	Cutterhead & connection	3	2	2.000.000
Mining	HRT	Machine body, powerpack and controls	3	5	2.000.000
Mining	HRT	Traveling carriage	2	10	1.000.000
Mining	HRT	Material collection system	3	5	1.000.000
Mining	VRM	Booster Pumps	6	5	1.000.000
Mining	VRM	Pipe System incl. flexibles	1	10	120.000.000
Mining	FPSO	Hull	1	25	200.000.000
Mining	FPSO	Riser Tower / Mooring	1	25	30.500.000
Mining	FPSO	Power Pack	1	10	1.000.000
Mining	FPSO	Crane 25t	1	25	5.000.000
Mining	FPSO	Crane 20t	1	25	3.500.000
Mining	FPSO	Crane 5t	3	25	1.000.000
Mining	FPSO	Dynamic Positioning System	1	15	500.000
Mining	FPSO	Hotel Facilities	1	25	20.000.000
Mining	FPSO	Ancillary Projects @ 10%	1	25	26.150.000
PROCESSING					
Processing	FPSO	Power plant, Controls & instrumentation	1	25	100.000.000
Processing	FPSO	Storage Tank	1	25	75.000.000
Processing	FPSO	Primary separation	1	25	125.000.000
Processing	FPSO	Gas Treating	1	25	110.000.000
Processing	FPSO	Dehydration plant	1	25	25.000.000
Processing	FPSO	Water Handling plant & disposal system	1	25	50.000.000
Processing	FPSO	Solids Discharge equipment	1	25	50.000.000
Processing	FPSO	Trace Hydrocarbon Removal plant	1	25	25.000.000
Processing	FPSO	Solid Control	1	25	25.000.000
Processing	FPSO	CNG plant with offloading facilities including compressors	1	25	40.000.000
MAINTENANCE					
Maintenance	All	Equipment	1	2	3.000.000
Maintenance				25	
ANCILLARY AND INFRASTRUCTURE					
Ancillary and Infrastructure	Support Facility	Offices	1	50	1.000.000
Ancillary and Infrastructure	Support Facility	Workshop	1	30	2.500.000
Ancillary and Infrastructure	Communications	Communications	1	30	2.500.000
Ancillary and Infrastructure	Support Facility	Port	1	50	50.000.000
Ancillary and Infrastructure	Exploration & Mining I	Exploration & Mining Lease	1	30	5.000.000
Ancillary and Infrastructure	Ancillary Projects	Ancillary Projects	1	30	3.050.000

H. Results Cash Flow Analysis

Table H-1 Results Capital Expenditures and Depreciation

Total CAPEX & depreciation of: Gas Hydrate Bearing Sediments Project	2012	2013	2014	2015	2016	2017	2018	2019	Start up 2020	2021	2022	2023
Project Year	1	2	3	4	5	6	7	8	9	10	11	12
Production Year							2-	1-	1	2	3	4
MINING	-	-	-	-	-	-	432.650.000	-	-	-	6.000.000	-
Cutterhead & connection	-	-	-	-	-	-	6.000.000	-	-	-	6.000.000	-
Machine body, powerpack and controls	-	-	-	-	-	-	6.000.000	-	-	-	-	-
Traveling carriage	-	-	-	-	-	-	2.000.000	-	-	-	-	-
Material collection system	-	-	-	-	-	-	3.000.000	-	-	-	-	-
Booster Pumps	-	-	-	-	-	-	6.000.000	-	-	-	-	-
Pipe System incl. flexibles	-	-	-	-	-	-	120.000.000	-	-	-	-	-
Hull	-	-	-	-	-	-	200.000.000	-	-	-	-	-
Riser Tower / Mooring	-	-	-	-	-	-	30.500.000	-	-	-	-	-
Power Pack	-	-	-	-	-	-	1.000.000	-	-	-	-	-
Crane 25t	-	-	-	-	-	-	5.000.000	-	-	-	-	-
Crane 20t	-	-	-	-	-	-	3.500.000	-	-	-	-	-
Crane 5t	-	-	-	-	-	-	3.000.000	-	-	-	-	-
Dynamic Positioning System	-	-	-	-	-	-	500.000	-	-	-	-	-
Hotel Facilities	-	-	-	-	-	-	20.000.000	-	-	-	-	-
Ancillary Projects @ 10%	-	-	-	-	-	-	26.150.000	-	-	-	-	-
PROCESSING	-	-	-	-	-	-	625.000.000	-	-	-	-	-
Power plant, Controls & instrumentation	-	-	-	-	-	-	100.000.000	-	-	-	-	-
Storage Tank	-	-	-	-	-	-	75.000.000	-	-	-	-	-
Primary separation	-	-	-	-	-	-	125.000.000	-	-	-	-	-
Gas Treating	-	-	-	-	-	-	110.000.000	-	-	-	-	-
Dehydration plant	-	-	-	-	-	-	25.000.000	-	-	-	-	-
Water Handling plant & disposal system	-	-	-	-	-	-	50.000.000	-	-	-	-	-
Solids Discharge equipment	-	-	-	-	-	-	50.000.000	-	-	-	-	-
Trace Hydrocarbon Removal plant	-	-	-	-	-	-	25.000.000	-	-	-	-	-
Solid Control	-	-	-	-	-	-	25.000.000	-	-	-	-	-
CNG plant with offloading facilities including compressors	-	-	-	-	-	-	40.000.000	-	-	-	-	-
MAINTENANCE	-	-	-	-	-	-	-	-	-	-	3.000.000	-
Equipment	-	-	-	-	-	-	-	-	-	-	3.000.000	-
ANCILLARY AND INFRASTRUCTURE	11.000.000	-	-	-	-	-	53.050.000	-	-	-	-	-
Offices	1.000.000	-	-	-	-	-	-	-	-	-	-	-
Workshop	2.500.000	-	-	-	-	-	-	-	-	-	-	-
Communications	2.500.000	-	-	-	-	-	-	-	-	-	-	-
Port	-	-	-	-	-	-	50.000.000	-	-	-	-	-
Exploration & Mining Lease	5.000.000	-	-	-	-	-	-	-	-	-	-	-
Ancillary Projects	-	-	-	-	-	-	3.050.000	-	-	-	-	-
Contingency @ 10% or 1.000.000	1.100.000	1.000.000	1.000.000	1.000.000	1.000.000	1.000.000	111.070.000	1.000.000	1.000.000	1.000.000	900.000	1.000.000
Total Startup Capital	12.100.000	1.000.000	1.000.000	1.000.000	1.000.000	1.000.000	1.221.770.000	1.000.000	1.000.000	1.000.000	9.900.000	1.000.000
Cumulative CAPEX	12.100.000	13.100.000	14.100.000	15.100.000	16.100.000	17.100.000	1.238.870.000	1.239.870.000	1.240.870.000	1.241.870.000	1.251.770.000	1.252.770.000
DEPRECIATION												
Mining	-	-	-	-	-	-	29.859.333	29.859.333	29.859.333	29.859.333	29.859.333	29.859.333
Processing	-	-	-	-	-	-	25.000.000	25.000.000	25.000.000	25.000.000	25.000.000	25.000.000
Maintenance	-	-	-	-	-	-	1.500.000	1.500.000	1.500.000	1.500.000	1.500.000	1.500.000
Ancillary & Infrastructure	353.333	353.333	353.333	353.333	353.333	353.333	1.101.667	1.101.667	1.101.667	1.101.667	1.101.667	1.101.667
Contingency	37.931	73.645	110.682	149.144	189.144	230.811	5.059.941	5.105.396	5.153.015	5.203.015	5.250.383	5.305.939
Total Annual Depreciation	391.264	426.979	464.016	502.477	542.477	584.144	62.520.941	62.566.396	62.614.015	62.664.015	62.711.383	62.766.939
Cumulative Depreciation	391.264	818.243	1.282.259	1.784.736	2.327.213	2.911.357	65.432.298	127.998.694	190.612.708	253.276.723	315.988.106	378.755.044

Year	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	Total
Project Year	13	14	15	16	17	18	19	20	21	22	23	
Production Year	5	6	7	8	9	10	11	12	13	14	15	
MINING	6.000.000	15.000.000	6.000.000	-	6.000.000	-	144.000.000	-	6.000.000	-	6.000.000	
Cutterhead & connection	6.000.000	-	6.000.000	-	6.000.000	-	6.000.000	-	6.000.000	-	6.000.000	
Machine body, powerpack and controls	-	6.000.000	-	-	-	-	6.000.000	-	-	-	-	
Traveling carriage	-	-	-	-	-	-	2.000.000	-	-	-	-	
Material collection system	-	3.000.000	-	-	-	-	3.000.000	-	-	-	-	
Booster Pumps	-	6.000.000	-	-	-	-	6.000.000	-	-	-	-	
Pipe System incl. flexibles	-	-	-	-	-	-	120.000.000	-	-	-	-	
Hull	-	-	-	-	-	-	-	-	-	-	-	
Riser Tower / Mooring	-	-	-	-	-	-	-	-	-	-	-	
Power Pack	-	-	-	-	-	-	1.000.000	-	-	-	-	
Crane 25t	-	-	-	-	-	-	-	-	-	-	-	
Crane 20t	-	-	-	-	-	-	-	-	-	-	-	
Crane 5t	-	-	-	-	-	-	-	-	-	-	-	
Dynamic Positioning System	-	-	-	-	-	-	-	-	-	-	-	
Hotel Facilities	-	-	-	-	-	-	-	-	-	-	-	
Ancillary Projects @ 10%	-	-	-	-	-	-	-	-	-	-	-	
PROCESSING	-	-	-	-	-	-	-	-	-	-	-	
Power plant, Controls & instrumentation	-	-	-	-	-	-	-	-	-	-	-	
Storage Tank	-	-	-	-	-	-	-	-	-	-	-	
Primary separation	-	-	-	-	-	-	-	-	-	-	-	
Gas Treating	-	-	-	-	-	-	-	-	-	-	-	
Dehydration plant	-	-	-	-	-	-	-	-	-	-	-	
Water Handling plant & disposal system	-	-	-	-	-	-	-	-	-	-	-	
Solids Discharge equipment	-	-	-	-	-	-	-	-	-	-	-	
Trace Hydrocarbon Removal plant	-	-	-	-	-	-	-	-	-	-	-	
Solid Control	-	-	-	-	-	-	-	-	-	-	-	
CNG plant with offloading facilities including compressors	-	-	-	-	-	-	-	-	-	-	-	
MAINTENANCE	3.000.000	-	3.000.000	-	3.000.000	-	3.000.000	-	3.000.000	-	3.000.000	
Equipment	3.000.000	-	3.000.000	-	3.000.000	-	3.000.000	-	3.000.000	-	3.000.000	
ANCILLARY AND INFRASTRUCTURE	-	-	-	-	-	-	-	-	-	-	-	
Offices	-	-	-	-	-	-	-	-	-	-	-	
Workshop	-	-	-	-	-	-	-	-	-	-	-	
Communications	-	-	-	-	-	-	-	-	-	-	-	
Port	-	-	-	-	-	-	-	-	-	-	-	
Exploration & Mining Lease	-	-	-	-	-	-	-	-	-	-	-	
Ancillary Projects	-	-	-	-	-	-	-	-	-	-	-	
Contingency @ 10% or 1.000.000	900.000	1.500.000	900.000	1.000.000	900.000	1.000.000	14.700.000	1.000.000	900.000	1.000.000	900.000	
Total Startup Capital	9.900.000	16.500.000	9.900.000	1.000.000	9.900.000	1.000.000	161.700.000	1.000.000	9.900.000	1.000.000	9.900.000	1.484.470.000
Cumulative CAPEX	1.262.670.000	1.279.170.000	1.289.070.000	1.290.070.000	1.299.970.000	1.300.970.000	1.462.670.000	1.463.670.000	1.473.570.000	1.474.570.000	1.484.470.000	
DEPRECIATION												
Mining	29.859.333	29.859.333	29.859.333	29.859.333	29.859.333	29.859.333	29.859.333	29.859.333	29.859.333	29.859.333	29.859.333	507.608.667
Processing	25.000.000	25.000.000	25.000.000	25.000.000	25.000.000	25.000.000	25.000.000	25.000.000	25.000.000	25.000.000	25.000.000	425.000.000
Maintenance	1.500.000	1.500.000	1.500.000	1.500.000	1.500.000	1.500.000	1.500.000	1.500.000	1.500.000	1.500.000	1.500.000	25.500.000
Ancillary & Infrastructure	1.101.667	1.101.667	1.101.667	1.101.667	1.101.667	1.101.667	1.101.667	1.101.667	1.101.667	1.101.667	1.101.667	20.848.333
Contingency	5.358.880	5.452.630	5.512.630	5.584.058	5.653.289	5.736.622	7.072.986	7.172.986	7.272.986	7.397.986	7.526.557	101.610.655
Total Annual Depreciation	62.819.880	62.913.630	62.973.630	63.045.058	63.114.289	63.197.622	64.533.986	64.633.986	64.733.986	64.858.986	64.987.557	1.080.567.655
Cumulative Depreciation	441.574.924	504.488.554	567.462.184	630.507.242	693.621.531	756.819.153	821.353.139	885.987.126	950.721.112	1.015.580.098	1.080.567.655	

Table H-2 Results Operational Expenditures

RESULTS OPEX

Total OPEX of: Gas Hydrate Bearing Sediments Project																							
Year	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	Total
Project Year	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	
Start production									1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	
Management and Labour Costs	-	-	-	-	-	-	-	-	15.292.500	15.292.500	15.292.500	15.292.500	15.292.500	15.292.500	15.292.500	15.292.500	15.292.500	15.292.500	15.292.500	15.292.500	15.292.500	15.292.500	15.292.500	229.387.500
Fuel and lubricants Costs	-	-	-	-	-	-	-	-	50.108.947	50.108.947	50.108.947	50.108.947	50.108.947	50.108.947	50.108.947	50.108.947	50.108.947	50.108.947	50.108.947	50.108.947	50.108.947	50.108.947	50.108.947	751.634.205
Transportation Costs	-	-	-	-	-	-	-	-	35.027.283	35.027.283	35.027.283	35.027.283	35.027.283	35.027.283	35.027.283	35.027.283	35.027.283	35.027.283	35.027.283	35.027.283	35.027.283	35.027.283	35.027.283	525.409.251
Ancillary Costs	3.270.072	3.270.072	3.270.072	3.270.072	3.270.072	3.270.072	3.270.072	3.270.072	3.270.072	3.270.072	3.270.072	3.270.072	3.270.072	3.270.072	3.270.072	3.270.072	3.270.072	3.270.072	3.270.072	3.270.072	3.270.072	3.270.072	3.270.072	75.211.664
Production																								
Annual production	0	0	0	0	0	0	0	0	32.000.000	32.000.000	32.000.000	32.000.000	32.000.000	32.000.000	32.000.000	32.000.000	32.000.000	32.000.000	32.000.000	32.000.000	32.000.000	32.000.000	32.000.000	480.000.000
Cumulative production	0	0	0	0	0	0	0	0	32.000.000	64.000.000	96.000.000	128.000.000	160.000.000	192.000.000	224.000.000	256.000.000	288.000.000	320.000.000	352.000.000	384.000.000	416.000.000	448.000.000	480.000.000	3.840.000.000
OPEX rate per cube [US$/m^3]																								
OPEX	-3.270.072	-3.270.072	-3.270.072	-3.270.072	-3.270.072	-3.270.072	-3.270.072	-3.270.072	-103.698.803	-103.698.803	-103.698.803	-103.698.803	-103.698.803	-103.698.803	-103.698.803	-103.698.803	-103.698.803	-103.698.803	-103.698.803	-103.698.803	-103.698.803	-103.698.803	-103.698.803	-1.581.642.621

Table H-3 Results Revenue

Total Revenue with Mineral Resources of:	Gas Hydrate Bearing Sediments Project											
Year	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Project Year	1	2	3	4	5	6	7	8	9	10	11	12
Production Year									1	2	3	4
Nr. of Hydrate Recovery Tool	0	0	0	0	0	0	0	0	2	2	2	2
Production												
Annual Bulk Production [m3]	0	0	0	0	0	0	0	0	32.000.000	32.000.000	32.000.000	32.000.000
Annual Overburden	0	0	0	0	0	0	0	0	0	0	0	0
Annual Production after Mining Recovery rate	0	0	0	0	0	0	0	0	32.000.000	32.000.000	32.000.000	32.000.000
Annual Production after Processing Plant Recovery	0	0	0	0	0	0	0	0	32.000.000	32.000.000	32.000.000	32.000.000
Cumulative Production	0	0	0	0	0	0	0	0	32.000.000	64.000.000	96.000.000	128.000.000
Mineral Resources & Production												
Decreasing Mineral Resources	56.500.000	56.500.000	56.500.000	56.500.000	56.500.000	56.500.000	56.500.000	56.500.000	24.500.000	-7.500.000	-39.500.000	-71.500.000
Annual Bulk Production	0	0	0	0	0	0	0	0	32.000.000	32.000.000	32.000.000	32.000.000
Annual Overburden	0	0	0	0	0	0	0	0	0	0	0	0
Annual Production	0	0	0	0	0	0	0	0	32.000.000	32.000.000	32.000.000	32.000.000
Cumulative Production	0	0	0	0	0	0	0	0	32.000.000	64.000.000	96.000.000	128.000.000
Natural Gas Production [m³]												
Annual Gas Production	0	0	0	0	0	0	0	0	360.000.000	360.000.000	360.000.000	360.000.000
Cumulative Gas Production	0	0	0	0	0	0	0	0	360.000.000	720.000.000	1.080.000.000	1.440.000.000
Revenues												
Gross Revenue	0	0	0	0	0	0	0	0	53.496.215	53.496.215	53.496.215	53.496.215
Royalty	0	0	0	0	0	0	0	0	-1.604.886	-1.604.886	-1.604.886	-1.604.886
TOTAL REVENUES	0	0	0	0	0	0	0	0	51.891.328	51.891.328	51.891.328	51.891.328

Total Revenue with Mineral Resources of:												
Year	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	Total
Project Year	13	14	15	16	17	18	19	20	21	22	23	
Production Year	5	6	7	8	9	10	11	12	13	14	15	
Nr. of Hydrate Recovery Tool	2	2	2	2	2	2	2	2	2	2	2	
Production												
Annual Bulk Production [m3]	32.000.000	32.000.000	32.000.000	32.000.000	32.000.000	32.000.000	32.000.000	32.000.000	32.000.000	32.000.000	32.000.000	
Annual Overburden	0	0	0	0	0	0	0	0	0	0	0	
Annual Production after Mining Recovery rate	32.000.000	32.000.000	32.000.000	32.000.000	32.000.000	32.000.000	32.000.000	32.000.000	32.000.000	32.000.000	32.000.000	
Annual Production after Processing Plant Recovery	32.000.000	32.000.000	32.000.000	32.000.000	32.000.000	32.000.000	32.000.000	32.000.000	32.000.000	32.000.000	32.000.000	
Cumulative Production	160.000.000	192.000.000	224.000.000	256.000.000	288.000.000	320.000.000	352.000.000	384.000.000	416.000.000	448.000.000	480.000.000	
Mineral Resources & Production												
Decreasing Mineral Resources	-103.500.000	-135.500.000	-167.500.000	-199.500.000	-231.500.000	-263.500.000	-295.500.000	-327.500.000	-359.500.000	-391.500.000	-423.500.000	
Annual Bulk Production	32.000.000	32.000.000	32.000.000	32.000.000	32.000.000	32.000.000	32.000.000	32.000.000	32.000.000	32.000.000	32.000.000	
Annual Overburden	0	0	0	0	0	0	0	0	0	0	0	
Annual Production	32.000.000	32.000.000	32.000.000	32.000.000	32.000.000	32.000.000	32.000.000	32.000.000	32.000.000	32.000.000	32.000.000	
Cumulative Production	160.000.000	192.000.000	224.000.000	256.000.000	288.000.000	320.000.000	352.000.000	384.000.000	416.000.000	448.000.000	480.000.000	
Natural Gas Production [m³]												
Annual Gas Production	360.000.000	360.000.000	360.000.000	360.000.000	360.000.000	360.000.000	360.000.000	360.000.000	360.000.000	360.000.000	360.000.000	
Cumulative Gas Production	1.800.000.000	2.160.000.000	2.520.000.000	2.880.000.000	3.240.000.000	3.600.000.000	3.960.000.000	4.320.000.000	4.680.000.000	5.040.000.000	5.400.000.000	
Revenues												
Gross Revenue	53.496.215	53.496.215	53.496.215	53.496.215	53.496.215	53.496.215	53.496.215	53.496.215	53.496.215	53.496.215	53.496.215	802.443.220
Royalty	-1.604.886	-1.604.886	-1.604.886	-1.604.886	-1.604.886	-1.604.886	-1.604.886	-1.604.886	-1.604.886	-1.604.886	-1.604.886	-24.073.297
TOTAL REVENUES	51.891.328	51.891.328	51.891.328	51.891.328	51.891.328	51.891.328	51.891.328	51.891.328	51.891.328	51.891.328	51.891.328	778.369.924

ANNUAL PRODUCTION	
Amount of HRT	2
Hydrate Recovery Tool	16.000.000
Total Hydrate Recovery Tool	32.000.000
INCOME	
Price US$/MMBTU	4,20
Gas yield in GHBS [m³/m³]	11,25
Mining Recovery	100%
Processing Recovery	100%
Overburden Ratio	0%
CALCULATED REV PER CUBE$_{SEDIMENT}$	
US$/m³	1,67
CALCULATED	7,93 x Mineral Resources
OTHER	
Royalty	3,0%
$V_{Overburden}/V_{bulk}$ Ratio	0,0%
Closure Year	2040
Mineral Resources (m³)	56.500.000

Table H-4 Residual Value

Equipment	Quantity	Life [yr]	Cost Unit [US$]	Year Project Year Production Year	2012 1	2013 2	2014 3	2015 4	2016 5	2017 6	2018 7	2019 8	2020 9 1	2021 10 2	2022 11 3	2023 12 4	2024 13 5	2025 14 6	2026 15 7	2027 16 8	2028 17 9	2029 18 10	2030 19 11	2031 20 12	2032 21 13	2033 22 14	2034 23 15	Total
					-	-	-	-	-	-	-	-	432.650.000	402.790.667	378.931.333	349.072.000	325.212.667	310.353.333	286.494.000	256.634.667	232.775.333	202.916.000	317.056.667	287.197.333	263.338.000	233.478.667	209.619.333	179.760.000
Cutterhead & connection	3	2	2.000.000										6.000.000	3.000.000	6.000.000	3.000.000	6.000.000	3.000.000	6.000.000	3.000.000	6.000.000	3.000.000	6.000.000	3.000.000	6.000.000	3.000.000	6.000.000	3.000.000
Machine body, powerpack and controls	3	5	2.000.000										6.000.000	4.800.000	3.600.000	2.400.000	1.200.000	6.000.000	4.800.000	3.600.000	2.400.000	1.200.000	6.000.000	4.800.000	3.600.000	2.400.000	1.200.000	-
Traveling carriage	2	10	1.000.000										2.000.000	1.800.000	1.600.000	1.400.000	1.200.000	1.000.000	800.000	600.000	400.000	200.000	2.000.000	1.800.000	1.600.000	1.400.000	1.200.000	1.000.000
Material collection system	3	5	1.000.000										3.000.000	2.400.000	1.800.000	1.200.000	600.000	3.000.000	2.400.000	1.800.000	1.200.000	600.000	3.000.000	2.400.000	1.800.000	1.200.000	600.000	-
Booster Pumps	6	5	1.000.000										6.000.000	4.800.000	3.600.000	2.400.000	1.200.000	6.000.000	4.800.000	3.600.000	2.400.000	1.200.000	6.000.000	4.800.000	3.600.000	2.400.000	1.200.000	-
Pipe System incl. flexibles	1	10	120.000.000										120.000.000	108.000.000	96.000.000	84.000.000	72.000.000	60.000.000	48.000.000	36.000.000	24.000.000	12.000.000	120.000.000	108.000.000	96.000.000	84.000.000	72.000.000	60.000.000
Hull	1	25	200.000.000										200.000.000	192.000.000	184.000.000	176.000.000	168.000.000	160.000.000	152.000.000	144.000.000	136.000.000	128.000.000	120.000.000	112.000.000	104.000.000	96.000.000	88.000.000	80.000.000
Riser Tower / Mooring	1	25	30.500.000										30.500.000	29.280.000	28.060.000	26.840.000	25.620.000	24.400.000	23.180.000	21.960.000	20.740.000	19.520.000	18.300.000	17.080.000	15.860.000	14.640.000	13.420.000	12.200.000
Power Pack	1	10	1.000.000										1.000.000	900.000	800.000	700.000	600.000	500.000	400.000	300.000	200.000	100.000	1.000.000	900.000	800.000	700.000	600.000	500.000
Crane 25t	1	25	5.000.000										5.000.000	4.800.000	4.600.000	4.400.000	4.200.000	4.000.000	3.800.000	3.600.000	3.400.000	3.200.000	3.000.000	2.800.000	2.600.000	2.400.000	2.200.000	2.000.000
Crane 20t	1	25	3.500.000										3.500.000	3.360.000	3.220.000	3.080.000	2.940.000	2.800.000	2.660.000	2.520.000	2.380.000	2.240.000	2.100.000	1.960.000	1.820.000	1.680.000	1.540.000	1.400.000
Crane 5t	3	25	1.000.000										3.000.000	2.880.000	2.760.000	2.640.000	2.520.000	2.400.000	2.280.000	2.160.000	2.040.000	1.920.000	1.800.000	1.680.000	1.560.000	1.440.000	1.320.000	1.200.000
Dynamic Positioning System	1	15	500.000										500.000	466.667	433.333	400.000	366.667	333.333	300.000	266.667	233.333	200.000	166.667	133.333	100.000	66.667	33.333	0
Hotel Facilities	1	25	20.000.000										20.000.000	19.200.000	18.400.000	17.600.000	16.800.000	16.000.000	15.200.000	14.400.000	13.600.000	12.800.000	12.000.000	11.200.000	10.400.000	9.600.000	8.800.000	8.000.000
Ancillary Projects @ 10%	1	25	26.150.000										26.150.000	25.104.000	24.058.000	23.012.000	21.966.000	20.920.000	19.874.000	18.828.000	17.782.000	16.736.000	15.690.000	14.644.000	13.598.000	12.552.000	11.506.000	10.460.000
					-	-	-	-	-	-	-	-	625.000.000	600.000.000	575.000.000	550.000.000	525.000.000	500.000.000	475.000.000	450.000.000	425.000.000	400.000.000	375.000.000	350.000.000	325.000.000	300.000.000	275.000.000	250.000.000
Power plant, Controls & instrumentation	1	25	100.000.000										100.000.000	96.000.000	92.000.000	88.000.000	84.000.000	80.000.000	76.000.000	72.000.000	68.000.000	64.000.000	60.000.000	56.000.000	52.000.000	48.000.000	44.000.000	40.000.000
Storage Tank	1	25	75.000.000										75.000.000	72.000.000	69.000.000	66.000.000	63.000.000	60.000.000	57.000.000	54.000.000	51.000.000	48.000.000	45.000.000	42.000.000	39.000.000	36.000.000	33.000.000	30.000.000
Primary separation	1	25	125.000.000										125.000.000	120.000.000	115.000.000	110.000.000	105.000.000	100.000.000	95.000.000	90.000.000	85.000.000	80.000.000	75.000.000	70.000.000	65.000.000	60.000.000	55.000.000	50.000.000
Gas Treating	1	25	110.000.000										110.000.000	105.600.000	101.200.000	96.800.000	92.400.000	88.000.000	83.600.000	79.200.000	74.800.000	70.400.000	66.000.000	61.600.000	57.200.000	52.800.000	48.400.000	44.000.000
Dehydration plant	1	25	25.000.000										25.000.000	24.000.000	23.000.000	22.000.000	21.000.000	20.000.000	19.000.000	18.000.000	17.000.000	16.000.000	15.000.000	14.000.000	13.000.000	12.000.000	11.000.000	10.000.000
Water Handling plant & disposal system	1	25	50.000.000										50.000.000	48.000.000	46.000.000	44.000.000	42.000.000	40.000.000	38.000.000	36.000.000	34.000.000	32.000.000	30.000.000	28.000.000	26.000.000	24.000.000	22.000.000	20.000.000
Solids Discharge equipment	1	25	50.000.000										50.000.000	48.000.000	46.000.000	44.000.000	42.000.000	40.000.000	38.000.000	36.000.000	34.000.000	32.000.000	30.000.000	28.000.000	26.000.000	24.000.000	22.000.000	20.000.000
Trace Hydrocarbon Removal plant	1	25	25.000.000										25.000.000	24.000.000	23.000.000	22.000.000	21.000.000	20.000.000	19.000.000	18.000.000	17.000.000	16.000.000	15.000.000	14.000.000	13.000.000	12.000.000	11.000.000	10.000.000
Solid Control	1	25	25.000.000										25.000.000	24.000.000	23.000.000	22.000.000	21.000.000	20.000.000	19.000.000	18.000.000	17.000.000	16.000.000	15.000.000	14.000.000	13.000.000	12.000.000	11.000.000	10.000.000
CNG plant with offloading facilities including compressors	1	25	40.000.000										40.000.000	38.400.000	36.800.000	35.200.000	33.600.000	32.000.000	30.400.000	28.800.000	27.200.000	25.600.000	24.000.000	22.400.000	20.800.000	19.200.000	17.600.000	16.000.000
					-	-	-	-	-	-	-	-	3.000.000	1.500.000	3.000.000	1.500.000	3.000.000	1.500.000	3.000.000	1.500.000	3.000.000	1.500.000	3.000.000	1.500.000	3.000.000	1.500.000	3.000.000	1.500.000
Equipment	1	2	3.000.000										3.000.000	1.500.000	3.000.000	1.500.000	3.000.000	1.500.000	3.000.000	1.500.000	3.000.000	1.500.000	3.000.000	1.500.000	3.000.000	1.500.000	3.000.000	1.500.000
					11.000.000	10.646.667	10.293.333	9.940.000	9.586.667	9.233.333	8.880.000	8.526.667	61.223.333	59.768.333	58.313.333	56.858.333	55.403.333	53.948.333	52.493.333	51.038.333	49.583.333	48.128.333	46.673.333	45.218.333	43.763.333	42.308.333	40.853.333	39.398.333
Offices	1	50	1.000.000		1.000.000	980.000	960.000	940.000	920.000	900.000	880.000	860.000	840.000	820.000	800.000	780.000	760.000	740.000	720.000	700.000	680.000	660.000	640.000	620.000	600.000	580.000	560.000	540.000
Workshop	1	30	2.500.000		2.500.000	2.416.667	2.333.333	2.250.000	2.166.667	2.083.333	2.000.000	1.916.667	1.833.333	1.750.000	1.666.667	1.583.333	1.500.000	1.416.667	1.333.333	1.250.000	1.166.667	1.083.333	1.000.000	916.667	833.333	750.000	666.667	583.333
Communications	1	30	2.500.000		2.500.000	2.416.667	2.333.333	2.250.000	2.166.667	2.083.333	2.000.000	1.916.667	1.833.333	1.750.000	1.666.667	1.583.333	1.500.000	1.416.667	1.333.333	1.250.000	1.166.667	1.083.333	1.000.000	916.667	833.333	750.000	666.667	583.333
Port	1	50	50.000.000		-	-	-	-	-	-	-	-	50.000.000	49.000.000	48.000.000	47.000.000	46.000.000	45.000.000	44.000.000	43.000.000	42.000.000	41.000.000	40.000.000	39.000.000	38.000.000	37.000.000	36.000.000	35.000.000
Exploration & Mining Lease	1	30	5.000.000		5.000.000	4.833.333	4.666.667	4.500.000	4.333.333	4.166.667	4.000.000	3.833.333	3.666.667	3.500.000	3.333.333	3.166.667	3.000.000	2.833.333	2.666.667	2.500.000	2.333.333	2.166.667	2.000.000	1.833.333	1.666.667	1.500.000	1.333.333	1.166.667
Ancillary Projects	1	30	3.050.000		-	-	-	-	-	-	-	-	3.050.000	2.948.333	2.846.667	2.745.000	2.643.333	2.541.667	2.440.000	2.338.333	2.236.667	2.135.000	2.033.333	1.931.667	1.830.000	1.728.333	1.626.667	1.525.000
				Residual Value																								470.658.333

Table H-5 Results Cash flow 10 years

Cash Flow (10 years) of:	Gas Hydrate Bearing Sediments Project																		
Year	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	Total
Project Year	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	
Production Year									1	2	3	4	5	6	7	8	9	10	
Mineral Resources & Production																			
Decreasing Mineral Resources	56,500,000	56,500,000	56,500,000	56,500,000	56,500,000	56,500,000	56,500,000	56,500,000	24,500,000	-7,500,000	-39,500,000	-71,500,000	-103,500,000	-135,500,000	-167,500,000	-199,500,000	-231,500,000	-263,500,000	
Annual Bulk Production	0	0	0	0	0	0	0	0	32,000,000	32,000,000	32,000,000	32,000,000	32,000,000	32,000,000	32,000,000	32,000,000	32,000,000	32,000,000	
Annual Overburden	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Annual Production	0	0	0	0	0	0	0	0	32,000,000	32,000,000	32,000,000	32,000,000	32,000,000	32,000,000	32,000,000	32,000,000	32,000,000	32,000,000	
Cumulative Production	0	0	0	0	0	0	0	0	32,000,000	64,000,000	96,000,000	128,000,000	160,000,000	192,000,000	224,000,000	256,000,000	288,000,000	320,000,000	
Revenues																			
Product Revenues	0	0	0	0	0	0	0	0	53,496,215	53,496,215	53,496,215	53,496,215	53,496,215	53,496,215	53,496,215	53,496,215	53,496,215	53,496,215	534,962,147
Royalty	0	0	0	0	0	0	0	0	-1,604,886	-1,604,886	-1,604,886	-1,604,886	-1,604,886	-1,604,886	-1,604,886	-1,604,886	-1,604,886	-1,604,886	-16,048,864
Residual Revenue																		596,063,333	596,063,333
Total Revenues	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**51,891,328**	**51,891,328**	**51,891,328**	**51,891,328**	**51,891,328**	**51,891,328**	**51,891,328**	**51,891,328**	**51,891,328**	**647,954,662**	**1,114,976,616**
Costs																			
OPEX	-3,270,072	-3,270,072	-3,270,072	-3,270,072	-3,270,072	-3,270,072	-3,270,072	-3,270,072	-103,698,803	-103,698,803	-103,698,803	-103,698,803	-103,698,803	-103,698,803	-103,698,803	-103,698,803	-103,698,803	-103,698,803	-1,063,148,607
Depreciation	-391,264	-426,979	-464,016	-502,477	-542,477	-584,144	-62,520,941	-62,566,396	-62,614,015	-62,664,015	-62,711,383	-62,766,939	-62,819,880	-62,913,630	-62,973,630	-63,045,058	-63,114,289	-63,197,622	-756,819,153
Total Costs	**-3,661,337**	**-3,697,051**	**-3,734,088**	**-3,772,550**	**-3,812,550**	**-3,854,216**	**-65,791,013**	**-65,836,468**	**-166,312,817**	**-166,362,817**	**-166,410,186**	**-166,465,741**	**-166,518,683**	**-166,612,433**	**-166,672,433**	**-166,743,861**	**-166,813,092**	**-166,896,425**	**-1,819,967,760**
Earnings Before Interest and tax (EBIT)	**-3,661,337**	**-3,697,051**	**-3,734,088**	**-3,772,550**	**-3,812,550**	**-3,854,216**	**-65,791,013**	**-65,836,468**	**-114,421,489**	**-114,471,489**	**-114,518,858**	**-114,574,413**	**-114,627,354**	**-114,721,104**	**-114,781,104**	**-114,852,533**	**-114,921,764**	**481,058,236**	**-704,991,144**
Carried Forward Loss	0	-3,661,337	-7,732,561	-12,331,100	-17,212,571	-22,396,879	-27,898,375	-95,625,648	-194,220,717	-373,000,932	-555,706,250	-744,434,355	-939,641,965	-1,141,636,452	-1,350,787,571	-1,567,793,992	-1,793,038,599	-2,026,530,744	-10,873,650,048
Interest		-374,173	-864,452	-1,108,921	-1,371,759	-1,647,280	-1,936,259	-32,758,601	-64,358,726	-68,233,829	-74,209,247	-80,633,198	-87,367,132	-94,430,014	-102,225,317	-110,392,074	-118,570,382	-127,157,317	
Net income before Tax	**-3,661,337**	**-7,732,561**	**-12,331,100**	**-17,212,571**	**-22,396,879**	**-27,898,375**	**-95,625,648**	**-194,220,717**	**-373,000,932**	**-555,706,250**	**-744,434,355**	**-939,641,965**	**-1,141,636,452**	**-1,350,787,571**	**-1,567,793,992**	**-1,793,038,599**	**-2,026,530,744**	**-1,672,629,826**	**-12,546,279,874**
Federal Income Taxes @ 30%	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Net Profit after Tax	**-3,661,337**	**-7,732,561**	**-12,331,100**	**-17,212,571**	**-22,396,879**	**-27,898,375**	**-95,625,648**	**-194,220,717**	**-373,000,932**	**-555,706,250**	**-744,434,355**	**-939,641,965**	**-1,141,636,452**	**-1,350,787,571**	**-1,567,793,992**	**-1,793,038,599**	**-2,026,530,744**	**-1,672,629,826**	**-12,546,279,874**
Investment Analysis																			
Cash In with Non-Cash Expenditures																			
Net Profit after tax	-3,661,337	-7,732,561	-12,331,100	-17,212,571	-22,396,879	-27,898,375	-95,625,648	-194,220,717	-373,000,932	-555,706,250	-744,434,355	-939,641,965	-1,141,636,452	-1,350,787,571	-1,567,793,992	-1,793,038,599	-2,026,530,744	-1,672,629,826	-12,546,279,874
Depreciation	391,264	426,979	464,016	502,477	542,477	584,144	62,520,941	62,566,396	62,614,015	62,664,015	62,711,383	62,766,939	62,819,880	62,913,630	62,973,630	63,045,058	63,114,289	63,197,622	756,819,153
Carried Forwrd Loss	0	3,661,337	7,732,561	12,331,100	17,212,571	22,396,879	27,898,375	95,625,648	194,220,717	373,000,932	555,706,250	744,434,355	939,641,965	1,141,636,452	1,350,787,571	1,567,793,992	1,793,038,599	2,026,530,744	10,873,650,048
Cash In	**-3,270,072**	**-3,644,245**	**-4,134,524**	**-4,378,993**	**-4,641,831**	**-4,917,352**	**-5,206,331**	**-36,028,674**	**-116,166,201**	**-120,041,303**	**-126,016,722**	**-132,440,672**	**-139,174,607**	**-146,237,489**	**-154,032,791**	**-162,199,548**	**-170,377,857**	**417,098,541**	**-915,810,672**
Cash Out																			
CAPEX	-12,100,000	-1,000,000	-1,000,000	-1,000,000	-1,000,000	-1,000,000	-1,221,770,000	-1,000,000	-1,000,000	-1,000,000	-9,900,000	-1,000,000	-9,900,000	-16,500,000	-9,900,000	-1,000,000	-9,900,000	-1,000,000	-1,300,970,000
Working Capital	403,160	0	0	0	0	0	0	0	-809,223	0	0	0	0	0	0	0	0	0	0
Cash Out	**-11,696,840**	**-1,000,000**	**-1,000,000**	**-1,000,000**	**-1,000,000**	**-1,000,000**	**-1,221,770,000**	**-1,000,000**	**-1,809,223**	**-1,000,000**	**-9,900,000**	**-1,000,000**	**-9,900,000**	**-16,500,000**	**-9,900,000**	**-1,000,000**	**-9,900,000**	**-1,000,000**	**-1,301,376,064**
Net Cash Flow																			
Cash In	-3,270,072	-3,644,245	-4,134,524	-4,378,993	-4,641,831	-4,917,352	-5,206,331	-36,028,674	-116,166,201	-120,041,303	-126,016,722	-132,440,672	-139,174,607	-146,237,489	-154,032,791	-162,199,548	-170,377,857	417,098,541	-915,810,672
Cash Out	-11,696,840	-1,000,000	-1,000,000	-1,000,000	-1,000,000	-1,000,000	-1,221,770,000	-1,000,000	-1,809,223	-1,000,000	-9,900,000	-1,000,000	-9,900,000	-16,500,000	-9,900,000	-1,000,000	-9,900,000	-1,000,000	-1,301,376,064
Net Cash Flow	**-14,966,913**	**-4,644,245**	**-5,134,524**	**-5,378,993**	**-5,641,831**	**-5,917,352**	**-1,226,976,331**	**-37,028,674**	**-117,975,424**	**-121,041,303**	**-135,916,722**	**-133,440,672**	**-149,074,607**	**-162,737,489**	**-163,932,791**	**-163,199,548**	**-180,277,857**	**416,098,541**	**-2,217,186,736**
Cumulative Cash Flow	**-14,966,913**	**-19,611,158**	**-24,745,682**	**-30,124,675**	**-35,766,507**	**-41,683,859**	**-1,268,660,190**	**-1,305,688,864**	**-1,423,664,288**	**-1,544,705,591**	**-1,680,622,312**	**-1,814,062,985**	**-1,963,137,592**	**-2,125,875,081**	**-2,289,807,872**	**-2,453,007,420**	**-2,633,285,277**	**-2,217,186,736**	
Financing (Bank)	14,966,913	19,611,158	24,745,682	30,124,675	35,766,507	41,683,859	1,268,660,190	1,305,688,864	1,423,664,288	1,544,705,591	1,680,622,312	1,814,062,985	1,963,137,592	2,125,875,081	2,289,807,872	2,453,007,420	2,633,285,277	2,217,186,736	
Total Net Cash Flow	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	
	10 years																		
Net Present Value (with pre-production) @ 10%	**-1,718,030,999**																		
Internal Rate of Return	**#DIV/0!**																		

	Assumed
ANNUAL PRODUCTION	
Pilot DSM system	32,000,000
INCOME	
Price US$/m3	4.20
Average grade (m3/m3)	11.25
m3 / mmBtu	28.263682
Mining Recovery	100%
Processing Recovery	100%
Overburden Ratio	0%
CALCULATED REV PER CUBE	
US$/m3	1.67
ANNUAL OPEX	US$
Pilot DSM system	103,698,803
CAPEX Mining	US$
Initial CAPEX costs	1,121,700,000
OTHER	
VOverburden/Vbulk Ratio	0.0%
Royalty	3.0%
Corporate Tax Rate	30%
Closure Year	2030
Mineral Resources (m3)	2
NPV Discount Rate	15%

Table H-6 Results Cash flow 15 years

Cash Flow (15 years) of: Gas Hydrate Bearing Sediments Project

Year	2012	2013	2014	2015	2016	2017	2018	2019
Project Year	0	1	2	3	4	5	6	7
Production Year								
Mineral Resources & Production								
Decreasing Mineral Resources	56,500,000	56,500,000	56,500,000	56,500,000	56,500,000	56,500,000	56,500,000	56,500,000
Annual Bulk Production	0	0	0	0	0	0	0	0
Annual Overburden	0	0	0	0	0	0	0	0
Annual Production	0	0	0	0	0	0	0	0
Cumulative Production	0	0	0	0	0	0	0	0
Revenues								
Product Revenues	0	0	0	0	0	0	0	0
Royalty	0	0	0	0	0	0	0	0
Residual Revenue								
Total Revenues	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Costs								
OPEX	-3,270,072	-3,270,072	-3,270,072	-3,270,072	-3,270,072	-3,270,072	-3,270,072	-3,270,072
Depreciation	-391,264	-426,979	-464,016	-502,477	-542,477	-584,144	-62,520,941	-62,566,396
Total Costs	**-3,661,337**	**-3,697,051**	**-3,734,088**	**-3,772,550**	**-3,812,550**	**-3,854,216**	**-65,791,013**	**-65,836,468**
Earnings Before Interest and tax (EBIT)	**-3,661,337**	**-3,697,051**	**-3,734,088**	**-3,772,550**	**-3,812,550**	**-3,854,216**	**-65,791,013**	**-65,836,468**
Carried Forward Loss	0	-3,661,337	-7,732,561	-12,331,100	-17,212,571	-22,396,879	-27,898,375	-95,625,648
Interest		-374,173	-864,452	-1,108,921	-1,371,759	-1,647,280	-1,936,259	-32,758,601
Net income before Tax	**-3,661,337**	**-7,732,561**	**-12,331,100**	**-17,212,571**	**-22,396,879**	**-27,898,375**	**-95,625,648**	**-194,220,717**
Federal Income Taxes @ 30%	0	0	0	0	0	0	0	0
Net Profit after Tax	**-3,661,337**	**-7,732,561**	**-12,331,100**	**-17,212,571**	**-22,396,879**	**-27,898,375**	**-95,625,648**	**-194,220,717**
Investment Analysis								
Cash In with Non-Cash Expenditures								
Net Profit after tax	-3,661,337	-7,732,561	-12,331,100	-17,212,571	-22,396,879	-27,898,375	-95,625,648	-194,220,717
Depreciation	391,264	426,979	464,016	502,477	542,477	584,144	62,520,941	62,566,396
Carried Forward Loss	0	3,661,337	7,732,561	12,331,100	17,212,571	22,396,879	27,898,375	95,625,648
Cash In	**-3,270,072**	**-3,644,245**	**-4,134,524**	**-4,378,993**	**-4,641,831**	**-4,917,352**	**-5,206,331**	**-36,028,674**
Cash Out								
CAPEX	-12,100,000	-1,000,000	-1,000,000	-1,000,000	-1,000,000	-1,000,000	-1,221,770,000	-1,000,000
Working Capital	403,160	0	0	0	0	0	0	0
Cash Out	**-11,696,840**	**-1,000,000**	**-1,000,000**	**-1,000,000**	**-1,000,000**	**-1,000,000**	**-1,221,770,000**	**-1,000,000**
Net Cash Flow								
Cash In	-3,270,072	-3,644,245	-4,134,524	-4,378,993	-4,641,831	-4,917,352	-5,206,331	-36,028,674
Cash Out	-11,696,840	-1,000,000	-1,000,000	-1,000,000	-1,000,000	-1,000,000	-1,221,770,000	-1,000,000
Net Cash Flow Before Financing	-14,966,913	-4,644,245	-5,134,524	-5,378,993	-5,641,831	-5,917,352	-1,226,976,331	-37,028,674
Cumulative Cash Flow Before Financing	-14,966,913	-19,611,158	-24,745,682	-30,124,675	-35,766,507	-41,683,859	-1,268,660,190	-1,305,688,864
Financing (Bank)	14,966,913	19,611,158	24,745,682	30,124,675	35,766,507	41,683,859	1,268,660,190	1,305,688,864
Total Net Cash Flow	0	0	0	0	0	0	0	0

Year	2020	2021	2022	2023	2024	2025	2026	2027
Project Year	8	9	10	11	12	13	14	15
Production Year	1	2	3	4	5	6	7	8
Mineral Resources & Production								
Decreasing Mineral Resources	24,500,000	-7,500,000	-39,500,000	-71,500,000	-103,500,000	-135,500,000	-167,500,000	-199,500,000
Annual Bulk Production	32,000,000	32,000,000	32,000,000	32,000,000	32,000,000	32,000,000	32,000,000	32,000,000
Annual Overburden	0	0	0	0	0	0	0	0
Annual Production	32,000,000	32,000,000	32,000,000	32,000,000	32,000,000	32,000,000	32,000,000	32,000,000
Cumulative Production	32,000,000	64,000,000	96,000,000	128,000,000	160,000,000	192,000,000	224,000,000	256,000,000
Revenues								
Product Revenues	53,496,215	53,496,215	53,496,215	53,496,215	53,496,215	53,496,215	53,496,215	53,496,215
Royalty	-1,604,886	-1,604,886	-1,604,886	-1,604,886	-1,604,886	-1,604,886	-1,604,886	-1,604,886
Residual Revenue								
Total Revenues	**51,891,328**	**51,891,328**	**51,891,328**	**51,891,328**	**51,891,328**	**51,891,328**	**51,891,328**	**51,891,328**
Costs								
OPEX	-103,698,803	-103,698,803	-103,698,803	-103,698,803	-103,698,803	-103,698,803	-103,698,803	-103,698,803
Depreciation	-62,614,015	-62,664,015	-62,711,383	-62,766,939	-62,819,880	-62,913,630	-62,973,630	-63,045,058
Total Costs	**-166,312,817**	**-166,362,817**	**-166,410,186**	**-166,465,741**	**-166,518,683**	**-166,612,433**	**-166,672,433**	**-166,743,861**
Earnings Before Interest and tax (EBIT)	**-114,421,489**	**-114,471,489**	**-114,518,858**	**-114,574,413**	**-114,627,354**	**-114,721,104**	**-114,781,104**	**-114,852,533**
Carried Forward Loss	-194,220,717	-373,000,932	-555,706,250	-744,434,355	-939,641,965	-1,141,636,452	-1,350,787,571	-1,567,793,992
Interest	-64,358,726	-68,233,829	-74,209,247	-80,633,198	-87,367,132	-94,430,014	-102,225,317	-110,392,074
Net income before Tax	**-373,000,932**	**-555,706,250**	**-744,434,355**	**-939,641,965**	**-1,141,636,452**	**-1,350,787,571**	**-1,567,793,992**	**-1,793,038,599**
Federal Income Taxes @ 30%	0	0	0	0	0	0	0	0
Net Profit after Tax	**-373,000,932**	**-555,706,250**	**-744,434,355**	**-939,641,965**	**-1,141,636,452**	**-1,350,787,571**	**-1,567,793,992**	**-1,793,038,599**
Investment Analysis								
Cash In with Non-Cash Expenditures								
Net Profit after tax	-373,000,932	-555,706,250	-744,434,355	-939,641,965	-1,141,636,452	-1,350,787,571	-1,567,793,992	-1,793,038,599
Depreciation	62,614,015	62,664,015	62,711,383	62,766,939	62,819,880	62,913,630	62,973,630	63,045,058
Carried Forward Loss	194,220,717	373,000,932	555,706,250	744,434,355	939,641,965	1,141,636,452	1,350,787,571	1,567,793,992
Cash In	**-116,166,201**	**-120,041,303**	**-126,016,722**	**-132,440,672**	**-139,174,607**	**-146,237,489**	**-154,032,791**	**-162,199,548**
Cash Out								
CAPEX	-1,000,000	-1,000,000	-9,900,000	-1,000,000	-9,900,000	-16,500,000	-9,900,000	-1,000,000
Working Capital	-809,223	0	0	0	0	0	0	0
Cash Out	**-1,809,223**	**-1,000,000**	**-9,900,000**	**-1,000,000**	**-9,900,000**	**-16,500,000**	**-9,900,000**	**-1,000,000**
Net Cash Flow								
Cash In	-116,166,201	-120,041,303	-126,016,722	-132,440,672	-139,174,607	-146,237,489	-154,032,791	-162,199,548
Cash Out	-1,809,223	-1,000,000	-9,900,000	-1,000,000	-9,900,000	-16,500,000	-9,900,000	-1,000,000
Net Cash Flow Before Financing	-117,975,424	-121,041,303	-135,916,722	-133,440,672	-149,074,607	-162,737,489	-163,932,791	-163,199,548
Cumulative Cash Flow Before Financing	-1,423,664,288	-1,544,705,591	-1,680,622,312	-1,814,062,985	-1,963,137,592	-2,125,875,081	-2,289,807,872	-2,453,007,420
Financing (Bank)	1,423,664,288	1,544,705,591	1,680,622,312	1,814,062,985	1,963,137,592	2,125,875,081	2,289,807,872	2,453,007,420
Total Net Cash Flow	0	0	0	0	0	0	0	0

Year	2028	2029	2030	2031	2032	2033	2034	Total
Project Year	16	17	18	19	20	21	22	
Production Year	9	10	11	12	13	14	15	
Mineral Resources & Production								
Decreasing Mineral Resources	-231,500,000	-263,500,000	-295,500,000	-327,500,000	-359,500,000	-391,500,000	-423,500,000	
Annual Bulk Production	32,000,000	32,000,000	32,000,000	32,000,000	32,000,000	32,000,000	32,000,000	
Annual Overburden	0	0	0	0	0	0	0	
Annual Production	32,000,000	32,000,000	32,000,000	32,000,000	32,000,000	32,000,000	32,000,000	
Cumulative Production	288,000,000	320,000,000	352,000,000	384,000,000	416,000,000	448,000,000	480,000,000	
Revenues								
Product Revenues	53,496,215	53,496,215	53,496,215	53,496,215	53,496,215	53,496,215	53,496,215	802,443,220
Royalty	-1,604,886	-1,604,886	-1,604,886	-1,604,886	-1,604,886	-1,604,886	-1,604,886	-24,073,297
Residual Revenue							470,658,333	470,658,333
Total Revenues	**51,891,328**	**51,891,328**	**51,891,328**	**51,891,328**	**51,891,328**	**51,891,328**	**522,549,662**	**1,249,028,257**
Costs								
OPEX	-103,698,803	-103,698,803	-103,698,803	-103,698,803	-103,698,803	-103,698,803	-103,698,803	-1,581,642,621
Depreciation	-63,114,289	-63,197,622	-64,533,986	-64,633,986	-64,733,986	-64,858,986	-64,987,557	-1,080,567,655
Total Costs	**-166,813,092**	**-166,896,425**	**-168,232,789**	**-168,332,789**	**-168,432,789**	**-168,557,789**	**-168,686,360**	**-2,662,210,276**
Earnings Before Interest and tax (EBIT)	**-114,921,764**	**-115,005,097**	**-116,341,461**	**-116,441,461**	**-116,541,461**	**-116,666,461**	**353,863,301**	**-1,413,182,019**
Carried Forward Loss	-1,793,038,599	-2,026,530,744	-2,268,693,159	-2,521,198,003	-2,787,043,739	-3,066,786,539	-3,357,332,354	-24,874,703,842
Interest	-118,570,382	-127,157,317	-136,163,384	-149,404,275	-163,201,340	-173,879,354	-185,169,245	-1,775,456,279
Net income before Tax	**-2,026,530,744**	**-2,268,693,159**	**-2,521,198,003**	**-2,787,043,739**	**-3,066,786,539**	**-3,357,332,354**	**-3,188,638,298**	**-28,063,342,140**
Federal Income Taxes @ 30%	0	0	0	0	0	0	0	0
Net Profit after Tax	**-2,026,530,744**	**-2,268,693,159**	**-2,521,198,003**	**-2,787,043,739**	**-3,066,786,539**	**-3,357,332,354**	**-3,188,638,298**	**-28,063,342,140**
Investment Analysis								
Cash In with Non-Cash Expenditures								
Net Profit after tax	-2,026,530,744	-2,268,693,159	-2,521,198,003	-2,787,043,739	-3,066,786,539	-3,357,332,354	-3,188,638,298	-28,063,342,140
Depreciation	63,114,289	63,197,622	64,533,986	64,633,986	64,733,986	64,858,986	64,987,557	1,080,567,655
Carried Forward Loss	1,793,038,599	2,026,530,744	2,268,693,159	2,521,198,003	2,787,043,739	3,066,786,539	3,357,332,354	24,874,703,842
Cash In	**-170,377,857**	**-178,964,792**	**-187,970,858**	**-201,211,749**	**-215,008,815**	**-225,686,829**	**233,681,614**	**-2,108,070,643**
Cash Out								
CAPEX	-9,900,000	-1,000,000	-161,700,000	-1,000,000	-9,900,000	-1,000,000	-9,900,000	-1,484,470,000
Working Capital	0	0	0	0	0	0	0	-406,064
Cash Out	**-9,900,000**	**-1,000,000**	**-161,700,000**	**-1,000,000**	**-9,900,000**	**-1,000,000**	**-9,900,000**	**-1,484,876,064**
Net Cash Flow								
Cash In	-170,377,857	-178,964,792	-187,970,858	-201,211,749	-215,008,815	-225,686,829	233,681,614	-2,108,070,643
Cash Out	-9,900,000	-1,000,000	-161,700,000	-1,000,000	-9,900,000	-1,000,000	-9,900,000	-1,484,876,064
Net Cash Flow Before Financing	-180,277,857	-179,964,792	-349,670,858	-202,211,749	-224,908,815	-226,686,829	223,781,614	-3,592,946,707
Cumulative Cash Flow Before Financing	-2,633,285,277	-2,813,250,069	-3,162,920,927	-3,365,132,677	-3,590,041,491	-3,816,728,320	-3,592,946,707	
Financing (Bank)	2,633,285,277	2,813,250,069	3,162,920,927	3,365,132,677	3,590,041,491	3,816,728,320	3,592,946,707	
Total Net Cash Flow	0	0	0	0	0	0	0	

	15 years
Net Present Value (before pre-production phase) @ 10%	-785,789,446
Internal Rate of Return	#DIV/0!

	Assumed
ANNUAL PRODUCTION	
Pilot DSM system	32,000,000
INCOME	
Price US$/$m^3$	4.20
Average grade (m^3/m^3)	11.25
m3 / mmBtu	28.263682
Mining Recovery	100%
Processing Recovery	100%
Overburden Ratio	0%
CALCULATED REV PER CUBE	
US$/m3	1.67
ANNUAL OPEX	US$
Pilot DSM system	103,698,803
CAPEX Mining	US$
Initial CAPEX costs	1,121,700,000
OTHER	
$V_{Overburden}/V_{bulk}$ Ratio	0.0%
Royalty	3.0%
Corporate Tax Rate	30%
Closure Year	2035
Mineral Resources (m3)	2
NPV Discount Rate	15%

Table H-7 Results Cash flow 20 years

Cash Flow (20 years) of: Gas Hydrate Bearing Sediments Project

Year / Project Year / Production Year	2012 / 0	2013 / 1	2014 / 2	2015 / 3	2016 / 4	2017 / 5	2018 / 6	2019 / 7
Mineral Resources & Production								
Decreasing Mineral Resources	56,500,000	56,500,000	56,500,000	56,500,000	56,500,000	56,500,000	56,500,000	56,500,000
Annual Bulk Production	0	0	0	0	0	0	0	0
Annual Overburden	0	0	0	0	0	0	0	0
Annual Production	0	0	0	0	0	0	0	0
Cumulative Production	0	0	0	0	0	0	0	0
Revenues								
Product Revenues	0	0	0	0	0	0	0	0
Royalty	0	0	0	0	0	0	0	0
Residual Revenue								
Total Revenues	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Costs								
OPEX	-3,270,072	-3,270,072	-3,270,072	-3,270,072	-3,270,072	-3,270,072	-3,270,072	-3,270,072
Depreciation	-391,264	-426,979	-464,016	-502,477	-542,477	-584,144	-62,520,941	-62,566,396
Total Costs	**-3,661,337**	**-3,697,051**	**-3,734,088**	**-3,772,550**	**-3,812,550**	**-3,854,216**	**-65,791,013**	**-65,836,468**
Earnings Before Interest and tax (EBIT)	**-3,661,337**	**-3,697,051**	**-3,734,088**	**-3,772,550**	**-3,812,550**	**-3,854,216**	**-65,791,013**	**-65,836,468**
Carried Forward Loss	0	-3,661,337	-7,732,561	-12,331,100	-17,212,571	-22,396,879	-27,898,375	-95,625,648
Interest		-374,173	-864,452	-1,108,921	-1,371,759	-1,647,280	-1,936,259	-32,758,601
Net income before Tax	**-3,661,337**	**-7,732,561**	**-12,331,100**	**-17,212,571**	**-22,396,879**	**-27,898,375**	**-95,625,648**	**-194,220,717**
Federal Income Taxes @ 30%	0	0	0	0	0	0	0	0
Net Profit after Tax	**-3,661,337**	**-7,732,561**	**-12,331,100**	**-17,212,571**	**-22,396,879**	**-27,898,375**	**-95,625,648**	**-194,220,717**
Investment Analysis								
Cash In with Non-Cash Expenditures								
Net Profit after tax	-3,661,337	-7,732,561	-12,331,100	-17,212,571	-22,396,879	-27,898,375	-95,625,648	-194,220,717
Depreciation	391,264	426,979	464,016	502,477	542,477	584,144	62,520,941	62,566,396
Carried Forward Loss	0	3,661,337	7,732,561	12,331,100	17,212,571	22,396,879	27,898,375	95,625,648
Cash In	**-3,270,072**	**-3,644,245**	**-4,134,524**	**-4,378,993**	**-4,641,831**	**-4,917,352**	**-5,206,331**	**-36,028,674**
Cash Out								
CAPEX	-12,100,000	-1,000,000	-1,000,000	-1,000,000	-1,000,000	-1,000,000	-1,221,770,000	-1,000,000
Working Capital	403,160	0	0	0	0	0	0	0
Cash Out	**-11,696,840**	**-1,000,000**	**-1,000,000**	**-1,000,000**	**-1,000,000**	**-1,000,000**	**-1,221,770,000**	**-1,000,000**
Net Cash Flow								
Cash In	-3,270,072	-3,644,245	-4,134,524	-4,378,993	-4,641,831	-4,917,352	-5,206,331	-36,028,674
Cash Out	-11,696,840	-1,000,000	-1,000,000	-1,000,000	-1,000,000	-1,000,000	-1,221,770,000	-1,000,000
Net Cash Flow	-14,966,913	-4,644,245	-5,134,524	-5,378,993	-5,641,831	-5,917,352	-1,226,976,331	-37,028,674
Cumulative Cash Flow	-14,966,913	-19,611,158	-24,745,682	-30,124,675	-35,766,507	-41,683,859	-1,268,660,190	-1,305,688,864
Financing (Bank)	14,966,913	19,611,158	24,745,682	30,124,675	35,766,507	41,683,859	1,268,660,190	1,305,688,864
Total Net Cash Flow	0	0	0	0	0	0	0	0

Year / Project Year / Production Year	2020 / 8 / 1	2021 / 9 / 2	2022 / 10 / 3	2023 / 11 / 4	2024 / 12 / 5	2025 / 13 / 6	2026 / 14 / 7	2027 / 15 / 8
Mineral Resources & Production								
Decreasing Mineral Resources	24,500,000	-7,500,000	-39,500,000	-71,500,000	-103,500,000	-135,500,000	-167,500,000	-199,500,000
Annual Bulk Production	32,000,000	32,000,000	32,000,000	32,000,000	32,000,000	32,000,000	32,000,000	32,000,000
Annual Overburden	0	0	0	0	0	0	0	0
Annual Production	32,000,000	32,000,000	32,000,000	32,000,000	32,000,000	32,000,000	32,000,000	32,000,000
Cumulative Production	32,000,000	64,000,000	96,000,000	128,000,000	160,000,000	192,000,000	224,000,000	256,000,000
Revenues								
Product Revenues	53,496,215	53,496,215	53,496,215	53,496,215	53,496,215	53,496,215	53,496,215	53,496,215
Royalty	-1,604,886	-1,604,886	-1,604,886	-1,604,886	-1,604,886	-1,604,886	-1,604,886	-1,604,886
Residual Revenue								
Total Revenues	**51,891,328**	**51,891,328**	**51,891,328**	**51,891,328**	**51,891,328**	**51,891,328**	**51,891,328**	**51,891,328**
Costs								
OPEX	-103,698,803	-103,698,803	-103,698,803	-103,698,803	-103,698,803	-103,698,803	-103,698,803	-103,698,803
Depreciation	-62,614,015	-62,664,015	-62,711,383	-62,766,939	-62,819,880	-62,913,630	-62,973,630	-63,045,058
Total Costs	**-166,312,817**	**-166,362,817**	**-166,410,186**	**-166,465,741**	**-166,518,683**	**-166,612,433**	**-166,672,433**	**-166,743,861**
Earnings Before Interest and tax (EBIT)	**-114,421,489**	**-114,471,489**	**-114,518,858**	**-114,574,413**	**-114,627,354**	**-114,721,104**	**-114,781,104**	**-114,852,533**
Carried Forward Loss	-194,220,717	-373,000,932	-555,706,250	-744,434,355	-939,641,965	-1,141,636,452	-1,350,787,571	-1,567,793,992
Interest	-64,358,726	-68,233,829	-74,209,247	-80,633,198	-87,367,132	-94,430,014	-102,225,317	-110,392,074
Net income before Tax	**-373,000,932**	**-555,706,250**	**-744,434,355**	**-939,641,965**	**-1,141,636,452**	**-1,350,787,571**	**-1,567,793,992**	**-1,793,038,599**
Federal Income Taxes @ 30%	0	0	0	0	0	0	0	0
Net Profit after Tax	**-373,000,932**	**-555,706,250**	**-744,434,355**	**-939,641,965**	**-1,141,636,452**	**-1,350,787,571**	**-1,567,793,992**	**-1,793,038,599**
Investment Analysis								
Cash In with Non-Cash Expenditures								
Net Profit after tax	-373,000,932	-555,706,250	-744,434,355	-939,641,965	-1,141,636,452	-1,350,787,571	-1,567,793,992	-1,793,038,599
Depreciation	62,614,015	62,664,015	62,711,383	62,766,939	62,819,880	62,913,630	62,973,630	63,045,058
Carried Forward Loss	194,220,717	373,000,932	555,706,250	744,434,355	939,641,965	1,141,636,452	1,350,787,571	1,567,793,992
Cash In	**-116,166,201**	**-120,041,303**	**-126,016,722**	**-132,440,672**	**-139,174,607**	**-146,237,489**	**-154,032,791**	**-162,199,548**
Cash Out								
CAPEX	-1,000,000	-1,000,000	-9,900,000	-1,000,000	-9,900,000	-16,500,000	-9,900,000	-1,000,000
Working Capital	-809,223	0	0	0	0	0	0	0
Cash Out	**-1,809,223**	**-1,000,000**	**-9,900,000**	**-1,000,000**	**-9,900,000**	**-16,500,000**	**-9,900,000**	**-1,000,000**
Net Cash Flow								
Cash In	-116,166,201	-120,041,303	-126,016,722	-132,440,672	-139,174,607	-146,237,489	-154,032,791	-162,199,548
Cash Out	-1,809,223	-1,000,000	-9,900,000	-1,000,000	-9,900,000	-16,500,000	-9,900,000	-1,000,000
Net Cash Flow	-117,975,424	-121,041,303	-135,916,722	-133,440,672	-149,074,607	-162,737,489	-163,932,791	-163,199,548
Cumulative Cash Flow	-1,423,664,288	-1,544,705,591	-1,680,622,312	-1,814,062,985	-1,963,137,592	-2,125,875,081	-2,289,807,872	-2,453,007,420
Financing (Bank)	1,423,664,288	1,544,705,591	1,680,622,312	1,814,062,985	1,963,137,592	2,125,875,081	2,289,807,872	2,453,007,420
Total Net Cash Flow	0	0	0	0	0	0	0	0

Year / Project Year / Production Year	2028 / 16 / 9	2029 / 17 / 10	2030 / 18 / 11	2031 / 19 / 12	2032 / 20 / 13	2033 / 21 / 14	2034 / 22 / 15	2035 / 23 / 16
Mineral Resources & Production								
Decreasing Mineral Resources	-231,500,000	-263,500,000	-295,500,000	-327,500,000	-359,500,000	-391,500,000	-423,500,000	-455,500,000
Annual Bulk Production	32,000,000	32,000,000	32,000,000	32,000,000	32,000,000	32,000,000	32,000,000	32,000,000
Annual Overburden	0	0	0	0	0	0	0	0
Annual Production	32,000,000	32,000,000	32,000,000	32,000,000	32,000,000	32,000,000	32,000,000	32,000,000
Cumulative Production	288,000,000	320,000,000	352,000,000	384,000,000	416,000,000	448,000,000	480,000,000	512,000,000
Revenues								
Product Revenues	53,496,215	53,496,215	53,496,215	53,496,215	53,496,215	53,496,215	53,496,215	53,496,215
Royalty	-1,604,886	-1,604,886	-1,604,886	-1,604,886	-1,604,886	-1,604,886	-1,604,886	-1,604,886
Residual Revenue								
Total Revenues	**51,891,328**	**51,891,328**	**51,891,328**	**51,891,328**	**51,891,328**	**51,891,328**	**51,891,328**	**51,891,328**
Costs								
OPEX	-103,698,803	-103,698,803	-103,698,803	-103,698,803	-103,698,803	-103,698,803	-103,698,803	-103,698,803
Depreciation	-63,114,289	-63,197,622	-64,533,986	-64,633,986	-64,733,986	-64,858,986	-64,987,557	-65,237,557
Total Costs	**-166,813,092**	**-166,896,425**	**-168,232,789**	**-168,332,789**	**-168,432,789**	**-168,557,789**	**-168,686,360**	**-168,936,360**
Earnings Before Interest and tax (EBIT)	**-114,921,764**	**-115,005,097**	**-116,341,461**	**-116,441,461**	**-116,541,461**	**-116,666,461**	**-116,795,032**	**-117,045,032**
Carried Forward Loss	-1,793,038,599	-2,026,530,744	-2,268,693,159	-2,521,198,003	-2,787,043,739	-3,066,786,539	-3,357,332,354	-3,659,296,631
Interest	-118,570,382	-127,157,317	-136,163,384	-149,404,275	-163,201,340	-173,879,354	-185,169,245	-197,008,334
Net income before Tax	**-2,026,530,744**	**-2,268,693,159**	**-2,521,198,003**	**-2,787,043,739**	**-3,066,786,539**	**-3,357,332,354**	**-3,659,296,631**	**-3,973,349,997**
Federal Income Taxes @ 30%	0	0	0	0	0	0	0	0
Net Profit after Tax	**-2,026,530,744**	**-2,268,693,159**	**-2,521,198,003**	**-2,787,043,739**	**-3,066,786,539**	**-3,357,332,354**	**-3,659,296,631**	**-3,973,349,997**
Investment Analysis								
Cash In with Non-Cash Expenditures								
Net Profit after tax	-2,026,530,744	-2,268,693,159	-2,521,198,003	-2,787,043,739	-3,066,786,539	-3,357,332,354	-3,659,296,631	-3,973,349,997
Depreciation	63,114,289	63,197,622	64,533,986	64,633,986	64,733,986	64,858,986	64,987,557	65,237,557
Carried Forward Loss	1,793,038,599	2,026,530,744	2,268,693,159	2,521,198,003	2,787,043,739	3,066,786,539	3,357,332,354	3,659,296,631
Cash In	**-170,377,857**	**-178,964,792**	**-187,970,858**	**-201,211,749**	**-215,008,815**	**-225,686,829**	**-236,976,720**	**-248,815,809**
Cash Out								
CAPEX	-9,900,000	-1,000,000	-161,700,000	-1,000,000	-9,900,000	-1,000,000	-9,900,000	-16,500,000
Working Capital	0	0	0	0	0	0	0	0
Cash Out	**-9,900,000**	**-1,000,000**	**-161,700,000**	**-1,000,000**	**-9,900,000**	**-1,000,000**	**-9,900,000**	**-16,500,000**
Net Cash Flow								
Cash In	-170,377,857	-178,964,792	-187,970,858	-201,211,749	-215,008,815	-225,686,829	-236,976,720	-248,815,809
Cash Out	-9,900,000	-1,000,000	-161,700,000	-1,000,000	-9,900,000	-1,000,000	-9,900,000	-16,500,000
Net Cash Flow	-180,277,857	-179,964,792	-349,670,858	-202,211,749	-224,908,815	-226,686,829	-246,876,720	-265,315,809
Cumulative Cash Flow	-2,633,285,277	-2,813,250,069	-3,162,920,927	-3,365,132,677	-3,590,041,491	-3,816,728,320	-4,063,605,040	-4,328,920,848
Financing (Bank)	2,633,285,277	2,813,250,069	3,162,920,927	3,365,132,677	3,590,041,491	3,816,728,320	4,063,605,040	4,328,920,848
Total Net Cash Flow	0	0	0	0	0	0	0	0

Year / Project Year / Production Year	2036 / 24 / 17	2037 / 25 / 18	2038 / 26 / 19	2039 / 27 / 20	Total
Mineral Resources & Production					
Decreasing Mineral Resources	-487,500,000	-519,500,000	-551,500,000	-583,500,000	
Annual Bulk Production	32,000,000	32,000,000	32,000,000	32,000,000	
Annual Overburden	0	0	0	0	
Annual Production	32,000,000	32,000,000	32,000,000	32,000,000	
Cumulative Production	544,000,000	576,000,000	608,000,000	640,000,000	
Revenues					
Product Revenues	53,496,215	53,496,215	53,496,215	53,496,215	1,069,924,294
Royalty	-1,604,886	-1,604,886	-1,604,886	-1,604,886	-32,097,729
Residual Revenue				215,120,000	
Total Revenues	**51,891,328**	**51,891,328**	**51,891,328**	**267,011,328**	**1,252,946,565**
Costs					
OPEX	-103,698,803	-103,698,803	-103,698,803	-103,698,803	-2,100,136,634
Depreciation	-65,427,557	-65,677,557	-65,977,557	-66,477,557	-1,409,365,443
Total Costs	**-169,126,360**	**-169,376,360**	**-169,676,360**	**-170,176,360**	**-3,509,502,077**
Earnings Before Interest and tax (EBIT)	**-117,235,032**	**-117,485,032**	**-117,785,032**	**96,834,968**	**-2,256,555,512**
Carried Forward Loss	-3,973,349,997	-4,300,398,177	-4,641,131,017	-4,995,867,004	-46,444,746,669
Interest	-209,813,147	-223,247,808	-236,950,956	-251,318,798	
Net income before Tax	**-4,300,398,177**	**-4,641,131,017**	**-4,995,867,004**	**-5,150,350,835**	**-51,595,097,503**
Federal Income Taxes @ 30%	0	0	0	0	0
Net Profit after Tax	**-4,300,398,177**	**-4,641,131,017**	**-4,995,867,004**	**-5,150,350,835**	**-51,595,097,503**
Investment Analysis					
Cash In with Non-Cash Expenditures					
Net Profit after tax	-4,300,398,177	-4,641,131,017	-4,995,867,004	-5,150,350,835	-51,595,097,503
Depreciation	65,427,557	65,677,557	65,977,557	66,477,557	1,409,365,443
Carried Forward Loss	3,973,349,997	4,300,398,177	4,641,131,017	4,995,867,004	46,444,746,669
Cash In	**-261,620,622**	**-275,055,283**	**-288,758,430**	**-88,006,273**	**-3,740,985,392**
Cash Out					
CAPEX	-10,450,000	-1,000,000	-9,900,000	-1,000,000	-1,523,320,000
Working Capital	0	0	0	0	0
Cash Out	**-10,450,000**	**-1,000,000**	**-9,900,000**	**-1,000,000**	**-1,523,726,064**
Net Cash Flow					
Cash In	-261,620,622	-275,055,283	-288,758,430	-88,006,273	-3,740,985,392
Cash Out	-10,450,000	-1,000,000	-9,900,000	-1,000,000	-1,523,726,064
Net Cash Flow	-272,070,622	-276,055,283	-298,658,430	-89,006,273	-5,264,711,456
Cumulative Cash Flow	-4,600,991,470	-4,877,046,753	-5,175,705,183	-5,264,711,456	
Financing (Bank)	4,600,991,470	4,877,046,753	5,175,705,183	5,264,711,456	
Total Net Cash Flow	0	0	0	0	

	20 years
Net Present Value (with pre-production) @ 10%	-3,305,644,607
Internal Rate of Return	#DIV/0!

	Assumed
ANNUAL PRODUCTION	
Pilot DSM system	32,000,000
INCOME	
Price US$/m3	4.20
Average grade (m3/m3)	11.25
m3 / mmBtu	28.263682
Mining Recovery	100%
Processing Recovery	100%
Overburden Ratio	0%
CALCULATED REV PER CUBE	
US$/m3	1.67
ANNUAL OPEX	US$
Pilot DSM system	103,698,803
CAPEX Mining	US$
Initial CAPEX costs	1,121,700,000
OTHER	
VOverburden/Vbulk Ratio	0.0%
Royalty	3.0%
Corporate Tax Rate	30%
Closure Year	2040
Mineral Resources (m3)	2
NPV Discount Rate	15%