2010

Performance and economics of methane hydrate reservoirs

Lavanya Nyayapathi
West Virginia University

Follow this and additional works at: <https://researchrepository.wvu.edu/etd>

Recommended Citation

Nyayapathi, Lavanya, "Performance and economics of methane hydrate reservoirs" (2010). *Graduate Theses, Dissertations, and Problem Reports*. 3300.
<https://researchrepository.wvu.edu/etd/3300>

This Thesis is protected by copyright and/or related rights. It has been brought to you by the The Research Repository @ WVU with permission from the rights-holder(s). You are free to use this Thesis in any way that is permitted by the copyright and related rights legislation that applies to your use. For other uses you must obtain permission from the rights-holder(s) directly, unless additional rights are indicated by a Creative Commons license in the record and/ or on the work itself. This Thesis has been accepted for inclusion in WVU Graduate Theses, Dissertations, and Problem Reports collection by an authorized administrator of The Research Repository @ WVU. For more information, please contact researchrepository@mail.wvu.edu.

Performance and Economics of Methane Hydrate Reservoirs

Lavanya Nyayapathi

Thesis submitted to the
College of Engineering and Mineral Resources
at West Virginia University
in partial fulfillment of the requirements
for the degree of

**Master of Science
in
Chemical Engineering**

**Dr. Brian J. Anderson
Dr. H. Ilkin Bilgesu
Dr. Jerald Fletcher
Dr. Richard Turton**

**Department of Chemical Engineering
Morgantown, West Virginia
2010**

Key words: Gas hydrates, CMG STARS, Methane hydrate reservoir simulation, Gas production from hydrates, Sensitivity analysis, Economics.

Performance and Economics of Methane Hydrate Reservoirs

Abstract

Lavanya Nyayapathi

In order to address the world's growing energy demand, the necessity to explore more and more unconventional sources of energy arises. Recently there has been increased interest in the potential of natural gas hydrates as an alternate energy resource. Hydrates are distributed worldwide and have a high energy density in that 1 m³ of methane hydrates can release as much as 164 m³ of gas.

Hydrates were studied as a laboratory curiosity until and then naturally occurring hydrates were discovered in 1934 clogging gas and oil pipelines. The first naturally occurring hydrate deposits were suggested in 1965 by Makogon in Russia. Kvenvolden published the amount of first *In Situ* estimate of methane hydrates as $3053 \times 10^{15} \text{ m}^3$. Since then a number of researchers estimated the total resource of methane hydrates present throughout the oceans and the permafrost around the world. Today the estimates range from 105 trillion cubic feet (TCF) to 2.7×10^8 TCF; however, the estimates are speculative and debatable. It is widely believed that gas hydrates have an energy potential greater than that of the total conventional gas reserve.

Several researchers have reported preliminary economics of arctic hydrates. In 2004, Hancock et al., modeled a reservoir with Mallik's geological characters and estimated the production and economics using only depressurization of the hydrate reservoir. Hancock et al., in 2008 reported the lowest price that enabled economically-viable production from hydrates in the absence of associated free gas to be \$CDN₂₀₀₅ 12/Mscf and that in the presence of associated free gas to be \$CDN₂₀₀₅ 7.5/Mscf. The paper also stated that it was more expensive to produce gas from oceanic hydrates. This work will focus mainly on the Alaskan hydrate deposits and their economics.

In this work, Problem 7 of the DOE Code Comparison study was analyzed using reservoir simulations performed with the CMG STARS simulator and the Downdip of Prudhoe Bay L-Pad site was found to be the most economic site when gas is produced only by depressurization and as a basic estimate gas produced from this well would cost about \$2.25 . Because it has been suggested that the introduction of horizontal wells into a gas hydrate reservoir would yield higher gas rates at early times, the Prudhoe Bay down dip type reservoir was modeled using a vertical well and a horizontal well. The two well settings are compared based on production rates of gas and water and horizontal well produced at a wellhead breakeven price of \$2.87 and the vertical well produced at \$7.51/MMSCF after taxes and at a discount rate of 15%.

A financial Monte Carlo analysis was carried out on the Prudhoe Bay L-Pad like reservoir as this could be the most likely site to be drilled for gas production from hydrates in the near future. Wireline log data from the Mount Elbert stratigraphic test well was used to model the 100 different reservoir settings used in the MC analysis. The propagation of uncertainty of the reservoir parameters to the economics has been presented in this document and temperature has been found to be the most sensitive factor in the economics of a hydrate well site.

Acknowledgements

Firstly, I would like to thank my research advisor and chair to my thesis committee, Dr. Brian Anderson for his support, encouragement and patience though out this work. I would like to thank my committee members Dr. Jerry Fletcher, Dr. Ilkin Bilgesu and Dr. Richard Turton for their valuable time and suggestions in this work.

I want to thank my parents for being by my side at all times. I gratefully acknowledge all the help and encouragement I got from my husband, Manohar during this research.

Thanks to Aneesh Bethi for answering all of my random questions. Thanks to my fellow lab members for their friendship and cooperation.

Lavanya Nyayapathi

June 1, 2010.

Table of Contents

Abstract.....	ii
Acknowledgements.....	iii
List of Figures.....	vi
List of Tables	vii
1. Background.....	1
1.1 History of Hydrates.....	1
1.2 Hydrates in Natural Gas Industry	2
1.3 Chemistry of Hydrates	2
1.3.1 Structure I.....	5
1.3.2 Structure II	5
1.3.3 Structure H.....	5
1.4 Stability of Gas Hydrates.....	7
1.5 Location of gas hydrates around the world.....	8
1.6 Estimates of methane hydrates.....	9
1.7 Methods of production.....	11
1.7.1 Depressurization	11
1.7.2 Thermal Injection.....	12
1.7.3 Addition of Chemical Inhibitors	12
1.8 Importance of Methane Hydrate as a potential energy resource.....	12
1.9 Trends of Natural Gas Prices	17
1.10 Recent field studies in gas hydrates.....	18
1.11 Reservoir Simulations and Economics of Hydrates.....	20
1.12 Thesis Objectives	23
2. Economic evaluations of Prudhoe Bay and Mt. Elbert like sites of hydrate deposits ..	25
2.1 Common Criteria used to evaluate projects	26
2.1.1 Assumptions.....	27
2.2 Case Studies	27
2.2.1 Case 1:.....	27
2.2.2 Case 2:.....	32
2.2.3 Case 3:.....	37

2.3 Summary	40
3. Horizontal wells and vertical wells in Hydrate bearing reservoirs: Performance and Economics.....	42
3.1 Production using Horizontal Well – Reservoir Setup.....	42
3.2 Production using vertical well – Reservoir setup	50
3.3 Results	54
3.4 Economics.....	57
4. Economic Analysis of a Plackett-Burman Sensitivity Analysis	59
4.1 The Numerical Simulation Code	59
4.2 The Plackett-Burman design.....	62
4.3 Results	64
4.3.1 Effects based on breakeven prices	66
5. Sensitivity Analysis of hydrate bearing reservoirs: Stochastic sampling of input parameters	70
5.1 Introduction to Monte Carlo methods.....	70
5.2 The simulation model: Simulator used.	72
5.3 Input Variables and Method followed	73
5.4 Results.....	78
6. Conclusions and Future Work	84
6.1 Conclusions.....	84
6.2 Future Work	85
Appendix I	90
Appendix II	91

List of Figures

Figure 1- 1 Structures of hydrates	4
Figure 1- 2 Types of cavities in hydrates	4
Figure 1- 3 Pressure-temperature curve of methane hydrate.....	6
Figure 1-4 Methane Hydrate Stability Curves in Permafrost and Ocean floor.....	8
Figure 1-5 World map showing realized and expected hydrate sites	9
Figure 1-6 Total energy consumption in the US projected to 2030.....	13
Figure 1- 7 Total global energy consumption projected to 2030.....	14
Figure 1- 8 Natural gas production in the US by source	16
Figure 1- 9 Energy use in the US by source, Quadrillion Btu	16
Figure 1- 10 Wellhead natural gas prices in the US projected to 2030	18
Figure 2-1 Schematic view of the grid for Case 1	28
Figure 2-2 Case 1: Gas rate and Cumulative gas rate for 50 years using STARS	29
Figure 2-3 Case 1: Water rate & Cumulative water rate for 50 years using STARS	30
Figure 2- 4 Cumulative Cash flow for Case 1	31
Figure 2- 5 Rate of return Vs. Breakeven wellhead price	32
Figure 2-6 Case 2: Schematic view of the Prudhoe Bay L-Pad reservoir	33
Figure 2-7 Case 2: Gas rate and Cumulative gas rate for 50 years using CMG STARS.....	34
Figure 2-8 Case 2: Water production & cumulative water rate for 50 years using CMG STARS	34
Figure 2- 9 Cumulative cash flow for case 2 at wellhead of \$7/mscf.....	36
Figure 2- 10 IRR vs. Wellhead price for Case 2	36
Figure 2- 11 IRR Vs. NPV for Case 2.....	37
Figure 2-12 Case 3: Gas rate and Cumulative gas production for 50 years using CMG STARS.....	38
Figure 2-13 Case 3: Water rate and cumulative water production for 50 years using CMG STARS	38
Figure 2-14 Cumulative Cash Flow curve for Case 3 at \$7/mscf wellhead price	39
Figure 2- 15 Internal Rate of Return Vs. Wellhead price for Case 3.....	40
Figure 2- 16 Internal Rare of Return Vs. NPV for Case 3.....	40
Figure 3- 1 Reservoir used for the simulation including a horizontal well	43
Figure 3- 2 Slice of the reservoir simulated using CMG STARS	43
Figure 3- 3 Aqueous and Gas relative Permeability curves used in the reservoir	48
Figure 3- 4 Capillary Pressure as a function of water saturation.....	49
Figure 3- 5 Radial reservoir used for the simulation using a vertical well.....	50
Figure 3- 6 Gas Rate obtained from both cases, Million cubic meters/day.....	55
Figure 3-7 Cumulative gas production for both cases, Million cubic meters.....	55
Figure 3- 8 Water rate in both cases, cubic meters/day.....	56
Figure 3- 9 Cumulative water production, million cubic meters.....	56
Figure 3- 10 Cumulative cash flow diagram for reservoir with vertical well.....	57
Figure 3- 11 Cumulative cash flow diagram for reservoir with horizontal well.....	58
Figure 4-1 Gas hydrate deposits in the North Slope of Alaska.	60
Figure 4-2 Geometric representation of the reservoir grid	61
Figure 4-3 Schematic of the grid and its seven reservoir parameters	63
Figure 4-4 Box plot of breakeven prices for each Scenario	65
Figure 4- 5 Box plot Scenarios 4-8 in more detail.....	66
Figure 4-5 Effects of reservoir variables on breakeven prices for Scenarios 1-3	67
Figure 4-6 Effects of reservoir variables on breakeven prices for Scenarios 4-8	68
Figure 5- 1 Schematic of uncertainty propagation in MC analysis	71
Figure 5-2 Flowchart showing the Data Selection and Reservoir Creation process.....	73

Figure 5- 3 Distribution of hydrate saturation of actual and sampled data.....	74
Figure 5- 4 Distribution of permeability of actual and sampled data	75
Figure 5- 5 Distribution of water saturation of actual and sampled data.....	76
Figure 5-6 Distribution of porosity of actual and sampled data.	77
Figure 5- 7 Distribution of free water saturation of actual and sampled data.....	77
Figure 5- 8 Cumulative Production curves obtained from CMG STARS for the 100 reservoir models	79
Figure 5-9 Scatter Plot of the effects of the runs considered for analysis	80
Figure 5- 10 Histogram of effects, breakeven prices.....	80

List of Tables

Table 1- 1 Different cavities of hydrate crystals	3
Table 1- 2 Comparison of physical properties of ice and hydrates.....	7
Table 1- 3 Potential estimates of hydrates by geographic location	10
Table 1- 4 Various estimates of methane hydrates.....	10
Table 2- 1 Economic details used in this document	27
Table 2- 2 Summary of Cases 1, 2 & 3	41
Table 3- 1 Pressure and Temperature values in reservoir with horizontal well.....	44
Table 3- 2 Medium Properties for the Problem.....	48
Table 3- 3 Pressure and Temperature values for vertical well reservoir	51
Table 3- 4 Radius of individual cells.....	52
Table 3- 5 Discretization of the grid in z direction.....	53
Table 4-1 Reservoir parameters in the base case problem.....	61
Table 4-2 Plackett-Burman sensitivity analysis matrix	63
Table 4-3 Parameter specifications for different scenarios	64
Table 4-3 (contd...).....	64
Table 4-4 Breakeven prices in different cases of the PB design (expressed in \$/MMBTU).....	65
Table 5- 1 Descriptive statistics for the various input variables used in the simulations	78
Table 5- 2 Table of correlation coefficients	82

1. Background

Methane hydrate is a cage-like array of water molecules inside of which are trapped molecules of methane, the chief constituent of natural gas. Methane hydrates exist under conditions of high pressure and low temperature thus the hydrate will gasify if warmed or depressurized. One cubic meter of gas hydrate releases as much as 164 cubic meters¹ of natural gas if dissociated. Hydrate deposits can be several meters thick¹ and, in general, classified as permafrost hydrates and oceanic hydrates based on the site of occurrence, continental margins or the ocean floor. Methane in these deposits can be either thermogenic, created by geological processes, or biogenic, created by biological activity in sediments.

1.1 History of Hydrates

Hydrates are widely found in nature and many areas of occurrences have been so far discovered. However, the first instance of hydrates was observed in the laboratory. Chlorine hydrate was first discovered by Sir Humphrey Davy in 1810². Faraday corroborated the existence of chlorine hydrate in 1823 and quoted its formula to be $\text{Cl}_2 \cdot 10\text{H}_2\text{O}$. Villard, in 1888, first determined the existence of methane, ethane and propane hydrates². During 1930s, gas hydrates were discovered as crystalline formations that plugged natural gas pipelines². The first naturally occurring hydrate was discovered in the permafrost of Russia. Hydrates in Northern Canada and the oceanic hydrates in the Caspian and Black seas were later discovered.³

1.2 Hydrates in Natural Gas Industry

Hydrates have been known to clog pipelines since the early 1930s. Hydrates can grow rapidly in pipelines and are known to have caused pipeline fractures and fountains. Fountains happen when a pipeline fails and its contents gush out. Hydrates can form in pipelines where there is water, gas and conditions of pressure and temperature for hydrate formation. In general, low temperature and high pressure are required. Hydrates tend to form at elbows and valves⁴ and can pose major risk to pipelines causing flow assurance hindrance and can damage the valves and instrumentation. High gas velocity, turbulence and formation of a nucleation site may also show considerable influence of hydrate formation in pipes⁵.

1.3 Chemistry of Hydrates

Understanding the chemistry of natural gas hydrates paves way for the discovery of efficient methods of hydrate dissociation. Gas hydrates are non stoichiometric, solid compounds similar to ice crystals⁶ in which molecules of natural gases are trapped. The gas molecules interact with the water molecules through van der Waals forces. Methane hydrates are, by far, the most widely naturally occurring hydrates. Hydrates form due to the unusual behavior of water molecule and its orientation. A water molecule consists of one oxygen atom covalently bonded to two hydrogen atoms. The angle between the atoms is 104.5° . There are two unbound electrons which induce a partially-negative charge on the oxygen atom due to its high electronegativity relative to hydrogen atom. The partially-induced charges result in a weak bond between two water molecules in the form of hydrogen bonding. When the water molecules line up they arrange themselves in different patterns. Hydrates are formed due to this ability of water to form hydrogen

bonds. When hydrates are formed the guest molecules and the host molecules are held together by van der Waals force. There is no chemical bonding between the guest and the host molecules.

The most common crystal structure for water ice is the hexagonal structure. Depending on the guest gas molecules, gas hydrates can occur in many different crystal structures, with the most common being structure I, structure II, and structure H. Structures I and II crystallize in a cubic system structure H crystallizes in a hexagonal system.

The various hydrate structures can be seen in Figure 1-1. Figure 1-2 shows the type of cavities that are capable of holding guest molecules. The two cavities that constitute the structure I lattice are the pentagonal dodecahedron and tetrakaidecahedron. The pentagonal dodecahedron (5^{12}) has 12 pentagonal faces with equal edge lengths and angles. The tetrakaidecahedron ($5^{12}6^2$) has 12 pentagonal faces and two hexagonal faces. Different other cavities such as the irregular dodecahedron ($4^35^66^3$) etc are summarized in Table 1-1.

Table 1- 1 Different cavities of hydrate crystals⁷

Hydrate Crystal Structure	I		II		H		
Cavity	Small	Large	Small	Large	Small	Medium	Large
Description	5^{12}	$5^{12}6^2$	5^{12}	$5^{12}6^4$	5^{12}	$4^35^66^3$	$5^{12}6^8$
Number of cavities/unit cell	2	6	16	8	3	2	1
Average cavity radius (Å)	3.95	4.33	3.91	4.73	3.94	4.04	5.79
Variation in radius (%)	3.4	14.4	5.5	1.73	4.0	8.5	15.1
No. of water molecules/cavity	20	24	20	28	20	20	36

Figure 1- 1 Structures of hydrates⁸

Figure 1- 2 Types of cavities in hydrates (a) pentagonal dodecahedron (b) tetrakaidecahedron (c) hexakaidecahedron (d) irregular dodecahedron (e) icosahedron⁹ (Adapted from Sloan – Clathrate hydrates of natural gases)

1.3.1 Structure I

Structure I hydrate was first observed by McMullan and Jeffrey in 1965¹⁰ using ethylene oxide as a hydrate forming guest. Structure I is a primitive cubic lattice structure with a lattice constant of ~ 12 Å. In this structure 46 water molecules form a cage and accommodate 8 guest molecules of about 4 to 6 Å as there are only 8 polyhedra in the crystal. There are two small cavities of 5^{12} and six large cavities of $5^{12}6^2$. Examples of Structure I hydrates are methane, ethane, carbon dioxide and hydrogen sulfide hydrates. Structure I hydrates are the most widely found in nature since methane preferentially forms this structure.

1.3.2 Structure II

Mak and McMullan in 1965¹¹ studied the x-ray diffraction of H_2S hydrate after construing Structure II hydrate. The crystal forms face centered cubic structure and fits in a cube of side 17.3 Å. It consists of 136 water molecules per unit and has 16 small cages (5^{12}) and 8 large ($5^{12}6^4$) cages. This structure is not formed by methane hydrates but is seen in isopropylamine. However structure II can be formed by natural gas hydrates in depending on the guest molecules, particularly certain mixtures of Methane + Ethane or with the addition of propane

1.3.3 Structure H

Ripmeester proposed Structure H in 1987¹². Structure H has large cavities and can accommodate large molecules like n-butane etc. There are three different kinds of cages in Structure H and it consists of 34 water molecules associated with three 5^{12} cavity guest molecules, two $4^35^66^3$ cavity guest molecules and one $5^{12}6^2$ cavity guest molecules. Smaller guest molecules, such as CH_4 , N_2 and CO_2 occupy 5^{12} cavities, and large guest

molecules such as 2-methylbutane, methylcyclopentane, methylcyclohexane, ethylcyclohexane and cyclooctane occupy $4^35^66^3$ cavities. Structure H hydrates are known to exist in the Gulf of Mexico, where supplies of thermogenically-produced heavy hydrocarbons are common⁴. However Structure H hydrates are less common in nature than structure I and II.

Methane molecules are tightly packed in a lattice of water molecules due to crystallization forces. Methane hydrates have the highest energy density of any naturally occurring form of methane. The density of methane hydrate is a function of methane saturation and is approximately 0.9 g/cm^3 . Methane hydrate formation enthalpy at 273 K is 54 kJ/mol. Hydrates have a heat capacity of 257 kJ/mol at constant pressure. Hydrate properties are similar to ice¹³; Table 1-2 shows physical properties of ice and hydrate. The pressure-temperature equilibrium curve is given in Figure 1-3.

Figure 1- 3 Pressure-temperature curve of methane hydrate

Table 1- 2 Comparison of physical properties of ice and hydrates

Property	Ice	Hydrate
Dielectric constant at 273 K	94	58
Water molecule reorientation time at 273 K (μsec)	21	10
Isothermal Young's modulus at 268 K (109 Pa)	9.5	8.4
Poisson' ratio	0.33	0.33
Bulk modulus (272 K)	8.8	5.6
Shear modulus (272 K)	3.9	2.4
Bulk density (kg/m ³)	916	912
Adiabatic bulk compressibility at 273K 10 ⁻¹¹ Pa	12	14
Thermal Conductivity at 263 K (W/m-K)	2.25	0.49±0.02
Heat of Fusion (kJ/mol)	6	54(measured) ¹⁴ ,57(calculated) ¹⁴

1.4 Stability of Gas Hydrates

The thermodynamic conditions favoring hydrate formation and stability are low temperature, high pressure, availability of gas and water molecules. Gas hydrates are typically stable at a depth of 600 m or more in the ocean floor and 150 m or more in the permafrost.

Figure 1-4 shows the hydrate stability zone for methane both in permafrost and in oceanic sediments. The dashed line represents geo-thermal gradient. The slopes of the dashed lines are different due to different thermal conductivities which affect the thermal gradient. The phase-boundary line is obtained from the pressure-temperature equilibrium curve. The region between the phase-boundary line and the dashed line represents the hydrate stability zone. These curves are stability curves of methane hydrates. In other

heavy natural gas hydrates like propane and butane, we can observe an increase in the depth of the hydrate stability zone due to the shift of the phase-boundary line. The hydrates which are closer to the phase boundary line dissociate easily as their equilibrium can easily be perturbed.

Figure 1-4 Methane Hydrate Stability Curves in Permafrost and Ocean floor

1.5 Location of gas hydrates around the world

The current knowledge about hydrate location in the world is incomplete. The majority of known gas hydrate occurrences are on continental margins¹⁶. Figure 1-4 shows a map of locations of gas hydrates found out by different groups and scientists¹⁶. The black dots show places where gas hydrates have been inferred and the white dots are the places where samples have been recovered. The dotted lines on the Russian landmass are areas of possible hydrate deposits.

Figure 1-5 World map showing realized and expected hydrate sites¹⁷

1.6 Estimates of methane hydrates

Methane hydrates are an enormous unexploited energy resource. Estimates of the total volume of methane gas locked in hydrate deposits worldwide range widely from about 105 trillion standard cubic feet (TCF) to 2.7×10^8 TCF (i.e., 2.8×10^{15} to 7.6×10^{18} cubic meters)¹⁸. Even at the lower end of this range, the energy contained in the methane hydrate resource exceeds that of all known coal, oil, and natural gas reserves. If economically-viable recovery techniques can be developed, methane hydrates could play a major role in meeting the world's future energy needs. However, only small-scale field experiments have been conducted thus far. The various estimates of methane hydrates¹⁹ for different locations of the world are given in Table 1-3. The world's methane hydrate estimates¹⁹ are given in Table 1-4. There is a decrease in the estimated amount of methane content from hydrates due to the refinement of the prediction techniques.

Table 1- 3 Potential estimates of hydrates by geographic location

Hydrate potential	Value, TCF
World-oceanic hydrate potential	30,000 to 49,100,000 x 10 ¹²
World-continental hydrate potential	5,000 to 12,000,000 x 10 ¹²
United states hydrate potential	1,331 x 10 ¹²
Alaska hydrate potential	590 x 10 ¹²
India hydrate potential	4,307 x 10 ¹²
Japan hydrate potential	1,765 x 10 ¹²
World's conventional gas resources	13,000 x 10 ¹²

Table 1- 4 Various estimates of methane hydrates

Year	CH ₄ amount 10 ¹⁵ m ³ STP	Citations
1973	3053	<i>Trofimuk et al.</i>
1977	1135	<i>Trofimuk et al.</i>
1982	1573	<i>Cheriskiy et al.</i>
1981	120	<i>Trofimuk et al.</i>
1981	301	<i>McIver</i>
1974/1981	15	<i>Makogon</i>
1982	15	<i>Trofimuk et al.</i>
1988	40	<i>Kvenvolden and Claypool</i>
1988	20	<i>Kvenvolden</i>
1990	20	<i>MacDonald</i>
1994	26.4	<i>Gornitz and Fung</i>
1995	45.4	<i>Harvey and Huang</i>
1995	1	<i>Ginsburg and Soloviev</i>
1996	6.8	<i>Holbrook et al.</i>
1997	15	<i>Makogon</i>
2002	0.2	<i>Soloviev</i>
2004	2.5	<i>Milkov</i>
2005	120	<i>Klauda and Sandler</i>

1.7 Methods of production

Methods of dissociation of hydrates are based on shifting the thermodynamic equilibrium of the three phase water-hydrate-gas system. Gas can be produced from hydrates either by changing the pressure and temperature of the hydrate bearing media or by injection of inhibitors. Three main methods for producing gas from hydrates are depressurization, thermal stimulation and inhibitor addition. In the depressurization technique, the pressure is reduced below the equilibrium value at a fixed temperature; in thermal stimulation, the temperature is increased to shift equilibrium and bring about hydrate dissociation and adding inhibitors shifts the pressure temperature equilibrium.

1.7.1 Depressurization

Depressurization is often considered to be the method that is most likely to be economic for commercial production of gas hydrates¹⁵. In this case a production well is drilled into the hydrate reservoir and a pressure difference is created between the wellbore and the reservoir. Pressure reduction frees the methane molecules from hydrate. A reduction in the reservoir pressure is obtained by removing the associated free gas or formation water. Hydrate dissociates giving gas and water molecules, which migrate towards the wellbore. Different models were developed to describe the process of hydrate decomposition in the porous media. This method is likely to be the most economically feasible as there is no extra heat to be introduced into the system. The heat needed to drive the endothermic dissociation process is supplied by the in situ sensible heat of the reservoir.

1.7.2 Thermal Injection

In this method heat is introduced into the hydrate-bearing layer through an injector well. Injection wells require high pressure pumps to inject water or steam into the reservoir. The fluids injected are generally hot fluids which raises the temperature of the hydrate layer causing hydrate dissociation. Methane gases mix with hot water and return to the surface. Hydrate-bearing layers are generally found in permafrost and in oceans at a depth of 150 m and 600 m respectively. Considering heat losses to the surroundings, a lot of energy would be wasted to provide heat to the hydrate layer. As far as economics is concerned it is not likely feasible to produce gas from this method¹⁵.

1.7.3 Addition of Chemical Inhibitors

Salts, alcohols and glycols are the most commonly used gas hydrate inhibitors¹⁵. When an inhibitor such as methanol is added to hydrate formations, it shifts the P - T equilibrium and enables hydrate dissociation without changing the pressure or temperature of the hydrate layer. However, it is important that the inhibitor be added to the hydrate layer uniformly.

1.8 Importance of Methane Hydrate as a potential energy resource

Energy demand is ever increasing in the world. As the developing nations continue to grow and increase their energy usage in the coming years, the total global energy demand is all set to increase. It is projected that India and China's energy demand is going to increase at an annual rate of 3.75% due to the rapid economic growth of the countries²⁰. The world's energy demand is projected to increase 3% per year until 2020²⁰. The

majority of the globe uses energy from non-renewable resources like coal, petroleum and natural gas. Figure 1-6 shows the total use of energy in the United States projected through 2030 according to the EIA. Figure 1-7 shows the global energy consumption projected out to 2030.

Figure 1-6 Total energy consumption in the US projected to 2030²⁰

Figure 1- 7 Total global energy consumption projected to 2030²⁰

The major energy sources in the United States are petroleum, natural gas, coal, nuclear, and renewable energy, of which natural gas supplies more than 23% of the primary energy consumed annually²⁰. The share of each source of energy is shown in Figure 1-9. In the US, many industries utilize natural gas for their energy needs. According to the EIA, electricity generation from natural gas is expected to increase from 752 billion kilowatt-hours to 930 billion kWh in 2030. The net imports of natural gas by the US are projected to increase by 21% by the year 2030. Also, natural gas is the least polluting²¹ among all the fossil fuels in terms of CO₂ emissions. It is cleaner energy because natural gas produces lower amounts of carbon dioxide on a constant energy basis than coal or

petroleum. As the demand for energy increases worldwide, interest in alternatives to conventional sources is increases. Since methane hydrate has the highest energy density ($\approx 7 \times 10^9$ Joules/m³) of any naturally occurring form of methane²². A large potential for clean energy exists even a fraction of it is recoverable, providing the opportunity to greatly impact the world's energy scenario. Since hydrate deposits are known to act as stabilizers of geological strata, it may be important to know the behavior of hydrates to understand the hazards of drilling in the ocean floor and continental shelves. Methane is a green house gas and plays major role in global climate change²³ and there have been speculations about explosions of gas hydrates and occasional burps of large amounts of methane into the atmosphere in the past²⁴. Hence it is important to study methane hydrate in connection with natural gas demand as well as climate and geology.

Domestic conventional and unconventional natural gas production is outpaced by the natural gas demand. New alternatives like natural gas from methane hydrates could play a major role in ensuring future energy supplies for the United States. Unconventional natural gas production is predicted to increase from 47 percent of the U.S. total in 2007 to 56 percent in 2030²⁵. The various sources of production of natural gas²⁵ projected through the year 2030 are given in Figure 1-8.

Figure 1- 8 Natural gas production in the US by source²⁵ (adapted from EIA - Annual Energy Review, 2009)

Figure 1- 9 Energy use in the US by source, Quadrillion Btu²⁵ (adapted from EIA - Annual Energy Review, 2007)

1.9 Trends of Natural Gas Prices

Historically, oil prices have always been higher than natural gas prices and it is expected that the trend will continue. So it is possible that consumers would change to natural gas alternatives wherever possible. Natural gas is an important fuel for industries and for electricity generation. It is projected by the EIA that by the year 2030, 40% of the world's total natural gas would be consumed by the industrial sector. Electricity production would consume 35% of the world's natural gas in the year 2030 as projected by EIA²⁵. To cater to the needs for a growing natural gas demand, it is essential that there are 48 trillion cubic feet (TCF) more of natural gas. Figure 1-10 shows the trends, both historical and projected of natural gas wellhead price in the US lower 48 states²⁵. It shows five different cases viz. a reference, high growth, low growth, rapid technology and slow technology. The reference case is based upon an extrapolation of historical trends. In the rapid technology case, a sharp decline in exploration and development cost is assumed and so prices would be lower than the reference case prices. In the slow technology case, natural gas prices are higher than in the reference case due to high exploration and development costs. In the high economic growth case, natural gas prices increase more sharply because of the high demand of natural gas. In the low economic growth case, natural gas consumption grows more slowly, and natural gas prices are lower, than in the reference case.

Hydrates are potentially a large resource of energy. Commercially viable and environment friendly techniques are yet to be developed for the extraction of hydrates, but it is believed that hydrates can be efficiently extracted from conventional natural gas extraction methods²⁶.

Figure 1- 10 Wellhead natural gas prices in the US projected to 2030²⁵(adapted from EIA Energy outlook 2009)

1.10 Recent field studies in gas hydrates

The first hydrate test was carried out at the Mallik field in Canada in 1972²⁷. Minor methane recovery was observed. A collaborative drilling program was carried out at Mallik field in 1998²⁷ and hydrate bearing core samples were collected for research purposes. A high concentration of hydrate was observed as a result of this drilling program.

In March 2002, the first-ever production test was carried out on a permafrost methane hydrate-bearing layer in Canada's Mackenzie Delta region. In this test, both thermal stimulation through hot water circulation, and depressurization method were applied to

induce methane hydrate decomposition. Methane gas was produced as a result of the test which was flared off and not measured.

Later, in 2002²⁷, at the same field a test well was drilled and 6 days of petro-physical data was collected. That test flared gas over a short period indicating that it was actually possible to recover energy through hydrate dissociation.

In 2004, hydrate bearing sediments were recovered by drilling shallow wells at the Nankai Trough in Japan²⁷. Before this, in 1999-2000, a deep well was drilled for gas hydrates and conventional oil & gas exploration as well.

In 2006, in India, coring, drilling and down hole logging of gas hydrates was performed and samples were recovered at ten different sites in Krishna Godavari basin in order to study the distribution, the nature of gas hydrates, the flow processes and the geological factors that control hydrate formation in marine segments²⁸.

In 2007, two days of experimental-scale tests were performed at the Mt. Elbert site on the Alaskan North Slope²⁹. Modular Dynamics Testing was performed and the flow and pressure build-up data collected indicated that gas was produced. The pressure build up data was used to calculate the permeability of the reservoir.

At the Mallik site, a collaboration between Japan and Canada conducted a 60 hour flow test which reinforced the notion that production of gas from hydrate wells was feasible.

In 2008, sustained gas flow was first reported from a hydrate well at the Mallik field and it was concluded that methane gas equivalent to that of coal bed methane well was

produced³⁰. The economic viability of gas production from hydrates is not yet established but the tests are conducted to get an insight into technical feasibility of gas hydrates.

1.11 Reservoir Simulations and Economics of Hydrates

Reservoir simulation is a computational method of modeling the flow of fluid in porous media over time. A reservoir simulator is built on different mathematical models which represent the petro-physical properties of a reservoir. Usually a reservoir simulator is validated by performing history matching of the data obtained from different production wells. When the reservoir simulator is validated it is used as a tool to predict future production rates which are very important in making investment decisions. Reservoir simulators may be an effective tool to decide what technique is best suited to a particular reservoir setting. Gas hydrates are a novel field that could potentially produce large amounts of energy for the mankind but in reality, field scale experiments could be prohibitively expensive³¹. Also, the equipment required for gas production from a hydrate well could cost millions of dollars. Reservoir simulators impart confidence and motivation before deciding on a drilling project. Reservoir simulators have so far been considered an important tool in predictions about production potentials of hydrate-bearing reservoirs. Gas hydrate reservoirs require special production techniques due to the low temperature of the reservoir. Secondary hydrate formation and ice formation could make the dissociated gas difficult to produce due to the decreasing permeability of the reservoir due to solid formation. Hence, there are a number of problems like highly coupled heat flow, mass flow, phase transitions, physical and chemical properties that need to be addressed for a successful reservoir model. Based on reservoir simulations

performed by various scientists, hydrate reservoirs that contain free gas are easier to produce than those with no free gas because free gas can be easily removed from the reservoir³². This causes sustained depressurization of the reservoir and promotes hydrate dissociation.

In the United States, Alaska and the Gulf of Mexico contain large deposits of hydrates. The Alaskan permafrost is in the Arctic margin of the North American continent. There are several deposits of petroleum and conventional gas also in Alaska and proven deposits of gas hydrates. Factors that make the permafrost hydrates to be more thinkable for production are:

- The high quality of the deposits
- The assurance that the dissociated gas remains trapped until extracted
- Permafrost hydrates are shallower than oceanic hydrates
- Land drilling infrastructure being cheaper than ocean drilling infrastructure
- The chance of hydrates being associated with free gas or petroleum deposits rather being individual targets

By the early 1990's, reservoir simulations of hydrate-bearing reservoirs were carried out by Shell³³. Since then various research groups performed reservoir modeling and simulation of methane hydrates. Since 2008, the USGS and DOE have been coordinating a Code Comparison Study of all major hydrate reservoir simulators in the world³⁴. In the study various problem sets of different complexities have been defined, modeled and simulated using TOUGH Fx-Hydrate, CMG STARS, MH-21, Stomp, HydRessim and a

simulator from the University of Houston. The results obtained from all the reservoir simulators have been in good agreement with each other³⁵.

Several researchers have reported preliminary economics of arctic hydrates. In 2004, Hancock et al., modeled a reservoir with Mallik's geological characters and estimated the production and economics using only the depressurization technique. Hancock et al., in 2008 reported the lowest price that enabled economically viable production from hydrates in the absence of associated free gas to be \$CDN₂₀₀₅ 12/Mscf and that in the presence of associated free gas to be \$CDN₂₀₀₅ 7.5/Mscf. The paper also stated that it was more expensive to produce gas from oceanic hydrates.

This work will focus mainly on the Alaskan hydrate deposits and its economics. The economic viability of a resource makes it a reserve. Economic evaluations are important for reservoir models simulated as an effort to find out the economic viability of the reservoir. With the hope of unconventional gas to fill in the gap between domestic production and consumption of natural gas in the United States and the predictions say this gap would continue to increase, research continues to be done on various unconventional resources such as hydrates, coal bed methane, coal to liquids etc. Hydrates are of special interest since they hold the largest amount of methane of any

natural formation. Besides, the US has a proven vast deposit of hydrates both in the ocean, the Gulf of Mexico and in the permafrost, the Alaskan North Slope.

1.12 Thesis Objectives

This work is aimed at providing insights into the basic economics of gas production from hydrates and to study the sensitivity and uncertainty in the production from hydrate bearing reservoirs. Problem 7 of the DOE Code Comparison study³⁴ is analyzed using Net Present Value (NPV), Rate of Return (ROR) and Breakeven analysis and the economics are given. The three hypothetical cases of Problem 7 are the Mt. Elbert deposit³⁵, the Prudhoe Bay L-Pad 106 gas hydrate deposit³⁵ and a deposit down dip of the Prudhoe Bay deposit. The problem sets were defined by a panel of scientists who participated in the DOE Code Comparison study. The Prudhoe Bay L-Pad like site is studied for sensitivity of reservoir parameters and their effects on economics using a Plackett-Burman Design³⁶. Plackett-Burman design is like a subset of the factorial design and is easier than factorial design method to estimate sensitivity.

A horizontal well is introduced in a reservoir and its production and economics are compared with the same reservoir when a vertical well is used. It is widely accepted that introduction of horizontal wells into reservoir yield quicker and higher gas rates³⁷. The Prudhoe Bay down dip type reservoir will be modeled using a vertical well and a

horizontal well and their economics are compared. The two well settings are compared based on production rates of gas and water.

A financial Monte Carlo analysis is carried out on the Prudhoe Bay L-Pad like reservoir as this could be the most likely site to be drilled for gas production from hydrates. Wire line log data from the Mt. Elbert stratigraphic test well is used to model the 100 different reservoir settings used in the MC analysis. The aim of the MC analysis is to study the propagation of uncertainty of the reservoir parameters to the economics. The prices presented in this work will be representative of the type of reservoir specified and its geological conditions. The economic viability of a project is subject to its local geological settings and local taxes and tariffs. There have been reports on the preliminary economics of hydrates earlier. However, this work describes the economics along with uncertainty and sensitivity associated with hydrate production as estimated by reservoir simulations and design of experiments.

2. Economic evaluations of Prudhoe Bay and Mt. Elbert like sites of hydrate deposits

The North Slope of Alaska is home to a tremendous resource of methane hydrates due to the favorable geologic settings. Three sites are picked for evaluating the possible well head price range of natural gas that could potentially be produced from hydrates. They are the Mt. Elbert site at the Milne Point, the Prudhoe Bay L-Pad deposit and the down dip of Prudhoe Bay L-pad site. These have been chosen since Mt. Elbert has already undergone a Modular Dynamics Test as part of the BP/DOE ANS project and has undergone significant wireline logging while the Prudhoe Bay sites are warmer reservoirs with either known or inferred hydrate occurrence. These sites have reservoir simulations conducted on them as part of the International Methane Hydrate code comparison project^{35, 38}. An economic evaluation of these simulation studies is desirable to provide an initial estimate that could lead to realization of the commercial viability of natural gas production from hydrates.

The economic analysis in this chapter will be carried out using the net present value, breakeven prices and the rate of return criteria. The reservoir simulation results used will be those generated using Computer Modeling Group's Steam, Thermal and Advanced Processes Reservoir Simulator (CMG STARS). In the reservoir models, the anisotropy of the reservoirs has been replaced with the average value of each of the reservoir properties obtained from NMR well log data. Problem 7a is based on Mt. Elbert site. It is a cold reservoir and hydrate can be extremely stable making it difficult to produce gas from the Mt. Elbert site. It was solved using a radial cylindrical grid system. The Hydrate bearing

layer in this problem is bound by two shale zones. Problem 7b originates from Prudhoe Bay L-Pad site. This reservoir consists of two hydrate bearing layers surrounded by shale zones. It is warmer than the reservoir specified in Problem 7a. Problem 7c uses the same reservoir geometry as that of Problem 7b; the only difference being that it is deeper than the 7b reservoir. The reservoir simulation results are adapted from the International methane hydrate code comparison study. The reservoir models for the three case studies that are discussed here are performed by a colleague and detailed problem descriptions and solutions can be found from his thesis. ‘Manohar Gaddipati - Code Comparison of Methane Hydrate Reservoirs using CMG STARS’, 2008

2.1 Common Criteria used to evaluate projects

The net present value (NPV) criterion is considered as a standard measure of investment. It is the total present worth of future cash flows. The NPV method is used extensively for decision making regarding investments. It is used to realize the time value of money for approval of long term projects. The PV of a project is given by the following equation.

$$NPV(i) = \sum_{n=0}^N \frac{F_n}{(1+i)^n}$$

F_n is the net cash flow, i is the rate of interest or the discount rate, n is time period and N is the total time. A positive PV represents a positive surplus and the project is generally undertaken when sufficient capital is available for the project. Each cash inflow is discounted to the present value and the sum of all the discounted cash inflows gives the present value.

The internal rate of return (*IRR*) is also a time discounted measure of a project's worth similar to the *PV* criterion. The *IRR* of a project is defined as the rate of interest that equates the present value of the entire series of cash flows to zero.

The breakeven point is the point at which cost or expenses and revenues or cash inflows are equal. A breakeven point in business is calculated in order to estimate if the commodity would be profitable or not. A breakeven price is a price at which the cost of capital is recovered. When a commodity sells at a price higher than its breakeven price, it will create profits. These three methods are very commonly used to evaluate investment worth.

2.1.1 Assumptions

The exact drilling and maintenance costs of hydrate wells are not completely known. At this point, it is widely accepted that they will cost something like gas wells. Table 2-1 shows the economics used for calculating breakeven prices in this document.

Table 2- 1 Economic details used in this document

Drilling Cost	\$6 Million
Fixed Costs	\$1 Million per annum
Operating and Maintenance Costs	\$0.15/mscf
Discount Rate	15%
Corporation Tax Rate	35%

2.2 Case Studies

2.2.1 Case 1:

This case is the Problem 7a of the DOE code comparison project³⁸. This problem was solved using a cylindrical domain and a production well at the axis of the cylinder³⁹. The reservoir consists of a hydrate layer of thickness 12.5 m bound by two shale layers each

of 70 m. It is a cold reservoir and it is expected that hydrate here is extremely stable and it would be difficult to extract large amounts of natural gas from the deposit using the depressurization technique. A schematic view of the grid used is given in Figure 2-1.

Figure 2-1 Schematic view of the grid for Case 1

The initial hydrate saturation in the hydrate bearing zone is 65% and the water saturation is 35%. In the shale zone, there is no hydrate at all and the water saturation is 100%. The geothermal gradient is 35.5 K/km and the hydrostatic pressure gradient is 9792 Pa/m. The grid was discretized in both radial and vertical directions. In radial direction, it was discretized logarithmically and in the vertical direction uniform discretization was assumed. The upper boundary of the system is constantly at 274.715 K and the lower boundary is at 277.271 K. The permeability of shale is assumed to be 0 mD and that of

the hydrate layer is 100 mD in the z direction and 1000 mD in r direction. Porosities of shale and hydrate are 10% and 35% respectively. Stone & Aziz relative permeability model³⁹ and Van Genuchten capillary pressure model⁴⁰ were used in the modeling of this problem. The well bore radius is 0.111 m and the bottom hole well pressure is 2.7 MPa. The reservoir was modeled for production and flow behavior for 50 years using Computer Modeling group's Steam, Thermal, Advanced processes reservoir simulator(CMG STARS). Figure 2-2 shows the cumulative gas production and the gas rates obtained from Case 1. Water rates and cumulative water rates are given in Figure 2-3. The amount of water produced is very less.

Figure 2-2 Case 1: Gas rate and Cumulative gas rate for 50 years using CMG STARS

Figure 2-3 Case 1: water rate and cumulative water rate for 50 years using CMG STARS

2.2.1.1 Cash Flow Curve & Analysis for Case 1

Economic analysis for Case 1 description is conducted for this thesis. Figure 2-4 shows the cumulative cash flow curve for case 1 at a wellhead price of \$7/mscf since it has been the well head price more or less consistently. The well cost was assumed to be \$6 million but it can vary from \$5-10 million in reality depending upon the terrain and geography of the location. It is assumed that the costs associated with drilling, operation and maintenance are approximately equal to that of a natural gas well as there is no thorough knowledge of hydrate well economics. In reality, there could be significant difference in the way a conventional gas well operates and the way a hydrate well operates and also the costs associated with production such as lower bottom hole flowing pressure, chemical inhibitors, flow assurance systems etc. Fixed maintenance costs are taken as \$1 million per annum and operational costs are \$0.15/mscf. The discount rate is assured to be 15%. The timescale of the simulations was 50 years. However the cash flow analyses are done

only for 25 years since only the initial years of returns impact the net present value of a project. The cash flow curve remains negative throughout the project life and the project is never going to breakeven with this gas rate as seen in Figure 2.5. The same reservoir showed increased production rates when heterogeneity was incorporated in this reservoir⁴¹. Figure 2-5 shows the calculated wellhead price for each different rates of return. Even the 0% discount rate case is not economic to encourage drilling at this location.

Figure 2- 4 Cumulative Cash flow for Case 1

Figure 2- 5 Rate of return Vs. Breakeven wellhead price

2.2.2 Case 2:

This problem is also from the DOE code comparison project. It is called problem 7b in the Code Comparison Study. It is a reservoir description based on the Prudhoe Bay L-Pad hydrate deposit on the Alaskan North Slope. In this reservoir there are two hydrate-bearing layers that are bounded by three shale layers. It has higher overall temperatures than the Mt. Elbert site due to the deeper hydrate layers. Figure 2-6 shows a schematic view of the reservoir modeled. This reservoir was also modeled using a cylindrical domain.

Figure 2-6 Case 2: Schematic view of the Prudhoe Bay L-Pad reservoir

This grid is 240 m deep and has an outer radius of 450 m. The radial discretization of Case 2 grid is same as that of Case 1 grid. The hydrate bearing zones (H1 & H2) and the shale layer (S2) are uniformly discretized in the z -direction and the peripheral shale zones are logarithmically discretized. The hydrate saturation in hydrate bearing zones (H1 & H2) is assumed to be 75% and the water saturation is 25%. In the shale zones, there is no hydrate and the water saturation is 100%. Pressure and temperature at the top of H1 are 7.327 MPa and 278.15 K. The upper boundary temperature is 275.15 K and the lower boundary temperature is 282.5 K. The bottom hole pressure is 2.7 MPa and the well bore radius is 0.111 m. The reservoir simulation was carried out for 50 years using CMG STARS. Figure 2-7 shows the cumulative gas production and the gas rates over a time

period of 50 years. Figure 2-8 shows the cumulative water production and water rates obtained in Case 2.

Figure 2-7 Case 2: Gas rate and Cumulative gas rate for 50 years using CMG STARS

Figure 2-8 Case 2: Water production and cumulative water rate for 50 years using CMG STARS

2.2.2.1 Cash Flow curve & Analysis for Case 2

The reservoir produced higher gas than Case 1 which could be attributed to the high temperature of the reservoir. Unlike in Case 1, there are initial returns from this reservoir in the onset of the simulation. Projects like this one that produce at higher gas rates early in their lifetime have an advantage over slowly-producing wells as provide a better return on investment due to the time value of money.

Figure 2-9 shows the cumulative cash flow curve for case 2 at a wellhead price of \$7/mscf. The well cost was taken as \$6 million. Fixed maintenance costs are taken as \$1 million per annum and operational costs are \$0.15/mscf. The discount rate is 15%. The simulations were run for 50 years and cash flow analyses are done for 25 years just as in Case 1. The cash flow curve remains negative throughout the project life and the project is never going to breakeven at this gas production rate. Figure 2-5 shows the calculated wellhead price for each different rates of return. For a project life of 25 years and 15% rate of return, the wellhead breakeven price was calculated to be \$15/mscf. Figure 2-10 shows the internal rate of return versus wellhead price calculated. Figure 2-11 shows rate of return plotted against net present value (NPV). Case 2 yielded higher rates of gas production and resulted in slightly more favorable economic picture compared to Case 1. It is still higher than recent market prices of about \$5/MMBTU to \$8/MMBTU.

Figure 2- 9 Cumulative cash flow for case 2 at wellhead of \$7/mscf

Figure 2- 10 IRR vs. Wellhead price for Case 2

Figure 2- 11 IRR Vs. NPV for Case 2

2.2.3 Case 3:

The reservoir is Case 3 is an adaptation from the down dip of Prudhoe Bay L-Pad unit. It is much warmer than Case 2. The grid is same as that of Case 2. The temperature and pressure of the bottom of the hydrate bearing zone H1 are chosen as 12°C and 9.1 M Pa. The upper boundary is held constant at 280.8 K and the lower boundary temperature is held at 288.15 K. Gas production and gas rates are given in Figure 2 – 12. Water production and water rates are given in Figure 2-13. This reservoir produced large amounts of gas at high production rates. The production was also quicker resulting in production in the initial years of the simulation run time.

Figure 2-12 Case 3: Gas rate and Cumulative gas production for 50 years using CMG STARS

Figure 2-13 Case 3: Water rate and cumulative water production for 50 years using CMG STARS

2.2.3.1 Cash Flow curve & Analysis for Case 3

The reservoir in Case 3 is predicted to produce large amounts of gas at a higher production rate in the initial years of the project. The project breaks even after 3 years at a 15% discount rate and \$7/mscf wellhead price. All the factors used in calculations are same as those in that of Case 1 and Case 2. Figure 2-14 shows the cumulative cash flow for Case 3 reservoir. Lower wellhead prices are obtained for this reservoir when compared to the earlier ones owing to higher and quicker gas production. Figure 2-15 shows the wellhead prices obtained for different rates of return. The NPV for this case is positive, as can be seen in Figure 2-16. Since it is deeper reservoir, the hydrate-bearing layers are at a higher temperature and easier to dissociate by simple depressurization therefore suggesting favorable economics.

Figure 2-14 Cumulative Cash Flow curve for Case 3 at \$7/mscf wellhead price

Figure 2- 15 Internal Rate of Return Vs. Wellhead price for Case 3

Figure 2- 16 Internal Rare of Return Vs. NPV for Case 3

2.3 Summary

Overall, warmer reservoirs are predicted to produce gas in higher quantities and it could lead to the realization of hydrates as a reserve. Table 2-1 gives a summary of the various cases discussed in this chapter. Case 1 is highly unlikely to become an economically

viable deposit if stimulated only by depressurization. Heterogeneity in reservoirs seems to have significant effect in cold reservoirs. ®. Case 2 is warmer than Case 1 and more economical. Case 3 is warmer than Cases 1 & 2 and shows the most economic scenario.

Table 2- 2 Summary of Cases 1, 2 & 3

	Location	Characteristic	Lag	Breakeven Price*
Case 1	Mt. Elbert site	Cold Res.	10 years	\$375/MSCF
Case 2	Prudhoe Bay L-Pad	Warm Res.	Less than 0.5 yr	\$15/MSCF
Case 3	Down dip of Prudhoe Bay L-Pad	Warmer Res.	Negligible	\$2.25/MSCF

3. Horizontal wells and vertical wells in Hydrate bearing reservoirs: Performance and Economics

The objective of this chapter is to compare the performance and economics of vertical and horizontal wells in hydrate bearing reservoirs. It has been proven by several studies³⁷ that conventional type of wells using horizontal well technology and following the depressurization method for hydrate dissociation yield high amounts of gas from the hydrate reservoirs. This is an attempt to introduce a horizontal well in the hydrate bearing layer and compare it with the production from a similar reservoir when a vertical well is used. The reservoirs are adapted from Case Study 3 (Problem 7c) of the DOE Code Comparison Study³⁸. The Case study 3 was adapted for this comparison as it was the most economical of the 3 cases analyzed. In the case of a vertical well, a radial reservoir was used but for the horizontal well a rectangular Cartesian reservoir will be used as it simplifies the description of the horizontal well. The method of production in both cases is hydrate dissociation due to depressurization.

3.1 Production using Horizontal Well – Reservoir Setup

Figure 4-1 shows a schematic of the reservoir used to calculate production rates using a horizontal well at the bottom of the hydrate bearing layer. It is a $450\text{m} \times 450\text{ m} \times 245\text{ m}$ reservoir in i - j - k directions. For the actual simulation using CMG STARS, because of symmetry, only one slice in the j -direction of the reservoir is simulated which is later integrated in the j -direction to the entire reservoir. The slice simulated is shown in Figure 3-2. It is 1 m thick in the j -direction. The hydrate layer is discretized into 1 m blocks in the k -direction; the upper shale layer is discretized into 3 m blocks in the k -direction and

the lower shale layer is discretized into 2.5 m blocks in the k -direction. The entire reservoir is divided into 1 m blocks in i -direction. Hydrate saturation in the hydrate bearing layer is assumed to be 75% and so water saturation in the hydrate later is 25%. In the shale zone, water saturation is assumed to be 100% and hydrate saturation is zero.

Table 3-1 shows pressure and temperature values used in the reservoir at various depths according to the discretization used in the grid.

Figure 3- 1 Reservoir used for the simulation including a horizontal well

Figure 3- 2 Slice of the reservoir simulated using CMG STARS

Table 3- 1 Pressure and Temperature values in reservoir with horizontal well

Cell	Region	Depth, m	Temperature, °C	Pressure, k Pa
		0		
1	Shale	3	7.695	7694.69
2	Shale	6	7.785	7724.06
3	Shale	9	7.875	7753.44
4	Shale	12	7.965	7782.82
5	Shale	15	8.055	7812.19
6	Shale	18	8.145	7841.57
7	Shale	21	8.235	7870.94
8	Shale	24	8.325	7900.32
9	Shale	27	8.415	7929.70
10	Shale	30	8.505	7959.07
11	Shale	33	8.595	7988.45
12	Shale	36	8.685	8017.82
13	Shale	39	8.775	8047.20
14	Shale	42	8.865	8076.58
15	Shale	45	8.955	8105.95
16	Shale	48	9.045	8135.33
17	Shale	51	9.135	8164.70
18	Shale	54	9.225	8194.08
19	Shale	57	9.315	8223.46
20	Shale	60	9.405	8252.83
21	Shale	63	9.495	8282.21
22	Shale	66	9.585	8311.58
23	Shale	69	9.675	8340.96
24	Shale	72	9.765	8370.34
25	Shale	75	9.855	8399.71
26	Shale	78	9.945	8429.09
27	Shale	81	10.035	8458.46
28	Shale	84	10.125	8487.84
29	Shale	87	10.215	8517.22
30	Shale	90	10.305	8546.59
31	Shale	93	10.395	8575.97
32	Shale	96	10.485	8605.34
33	Shale	99	10.575	8634.72
34	Shale	102	10.665	8664.10
35	Shale	105	10.755	8693.47
36	Shale	108	10.845	8722.85
37	Shale	111	10.935	8752.22

Cell	Region	Depth, m	Temperature, °C	Pressure, k Pa
38	Shale	114	11.025	8781.60
39	Shale	117	11.115	8810.98
40	Shale	120	11.205	8840.35
41	Shale	123	11.295	8869.73
42	Shale	126	11.385	8899.10
43	Shale	127	11.445	8918.69
44	Hydrate	128	11.475	8928.48
45	Hydrate	129	11.505	8938.27
46	Hydrate	130	11.535	8948.06
47	Hydrate	131	11.565	8957.86
48	Hydrate	132	11.595	8967.65
49	Hydrate	133	11.625	8977.44
50	Hydrate	134	11.655	8987.23
51	Hydrate	135	11.685	8997.02
52	Hydrate	136	11.715	9006.82
53	Hydrate	137	11.745	9016.61
54	Hydrate	138	11.775	9026.40
55	Hydrate	139	11.805	9036.19
56	Hydrate	140	11.835	9045.98
57	Hydrate	141	11.865	9055.78
58	Hydrate	142	11.895	9065.57
59	Hydrate	143	11.925	9075.36
60	Hydrate	144	11.955	9085.15
61	Hydrate	145	11.985	9094.94
62	Shale	147.5	12.037	9112.08
63	Shale	150	12.112	9136.56
64	Shale	152.5	12.187	9161.04
65	Shale	155	12.262	9185.52
66	Shale	157.5	12.337	9210.00
67	Shale	160	12.412	9234.48
68	Shale	162.5	12.487	9258.96
69	Shale	165	12.562	9283.44
70	Shale	167.5	12.637	9307.92
71	Shale	170	12.712	9332.40
72	Shale	172.5	12.787	9356.88
73	Shale	175	12.862	9381.36
74	Shale	177.5	12.937	9405.84
75	Shale	180	13.012	9430.32

Cell	Region	Depth, m	Temperature, °C	Pressure, k Pa
76	Shale	182.5	13.087	9454.80
77	Shale	185	13.162	9479.28
78	Shale	187.5	13.237	9503.76
79	Shale	190	13.312	9528.24
80	Shale	192.5	13.387	9552.72
81	Shale	195	13.462	9577.20
82	Shale	197.5	13.537	9601.68
83	Shale	200	13.612	9626.16
84	Shale	202.5	13.687	9650.64
85	Shale	205	13.762	9675.12
86	Shale	207.5	13.837	9699.60
87	Shale	210	13.912	9724.08
88	Shale	212.5	13.987	9748.56
89	Shale	215	14.062	9773.04
90	Shale	217.5	14.137	9797.52
91	Shale	220	14.212	9822.00
92	Shale	222.5	14.287	9846.48
93	Shale	225	14.362	9870.96
94	Shale	227.5	14.437	9895.44
95	Shale	230	14.512	9919.92
96	Shale	232.5	14.587	9944.40
97	Shale	235	14.662	9968.88
98	Shale	237.5	14.737	9993.36
99	Shale	240	14.812	10017.84
100	Shale	242.5	14.887	10042.32
101	Shale	245	14.962	10066.80

Boundary Conditions:

There is no net mass transport between the reservoir and the surroundings. The upper boundary temperature is held constant at 7.8°C and the lower boundary temperature is held at constant at 15.15°C. The boundary conditions are same as that of the Case 3 reservoir mentioned in Chapter 2.

Initial Conditions:

A warm reservoir with temperature of 12°C is considered in this problem. The pressure and temperature of the bottom of the hydrate bearing zone are chosen as 12°C and 9.1 MPa. These high values are chosen considering the base of the hydrate stability zone. Pressure and temperature values of the entire reservoir are calculated based on the gradients 9792 Pa/m and 0.03 K/m.

Relative Permeability Models:

A relative permeability model developed by Stone³⁹ & Aziz³⁹ is used in this reservoir description. The reservoir parameters from the Code Comparison Study³⁸ are used for the description of the horizontal reservoir model as well.

Water Relative Permeability

$$k_{rw} = \left\{ \frac{(S_w - S_{wir})}{(1 - S_{wir})} \right\}^{5.04} ; S_{wir} = 0.10 \quad \text{eqn. (1)}$$

Gas Relative Permeability

$$k_{rg} = \left\{ \frac{(S_G - S_{Gir})}{(1 - S_{wir})} \right\}^{3.16} \quad \text{eqn. (2)}$$

$S_{wir} = 0$. $S_{Gir} = 0$. S_{wir} and S_{Gir} represents irreducible water and gas saturation. Gas and water relative permeability curves are shown in Figure 3-3.

Figure 3- 3 Aqueous and Gas relative Permeability curves used in the reservoir

Medium properties:

Medium properties like permeability porosity are specified in Table 3-2.

Table 3- 2 Medium Properties for the Problem

Property	Value
Permeability, mD	Shale - 0.0
	Hydrate layer – 1000 (r-direction)
	Hydrate layer - 100 (z-direction)
Porosity, %	Shale - 0
	Hydrate zone – 0.4
Pore Compressibility (1/Pa)	1.00E-08
Rock Density (kg/m ³)	2650
Rock Specific Heat (J/kg/K)	1000

Capillary Pressure Model:

Van Genuchten Capillary pressure Model³ is used in this reservoir.

$$\bar{s}_l = \frac{(s_l - s_{lr})}{(1 - s_{lr})} = \left[1 - \left(\alpha \beta_{gl} \left\{ \frac{(P_g - P_l)}{\rho_l g} \right\}^n \right)^m \right] :$$

$\alpha = 10.204 \text{ 1/m}, \beta_{gl} = 1.0, n = 4.432, m = 0.7744, s_{lr} = 0.28$ *eqn. (3)*

where $\bar{s}_l$ is the effective aqueous saturation, s_l is the aqueous saturation, β_{gl} is the interfacial tension scaling factor, and h_{gl} is the gas-aqueous capillary pressure head.

Figure 4-4 shows the variation of capillary pressure with water saturation.

Figure 3- 4 Capillary Pressure as a function of water saturation

Well Information:

The well radius is selected to be 0.111 m. The bottom hole pressure is chosen to be 2.7 MPa to avoid ice formation in the system.

Data and Sampling Frequency:

The simulations are carried over a time period of 50 years. Data for gas production rate, water production rate, cumulative gas production and cumulative water production is recorded with a time step of 0.001 days for 50 years.

3.2 Production using vertical well – Reservoir setup

Figure 3-5 shows the radial reservoir and the vertical well that is embedded in it. This is adapted from problem 7c of DOE code comparison study. The top hydrate layer is removed so as to reasonably compare it with the reservoir mentioned in section 3.1. All the properties are similar to that of the reservoir mentioned in section 3.1. Table 3-3 shows the pressure and temperature values at various depths in the reservoir.

Figure 3- 5 Radial reservoir used for the simulation using a vertical well

Table 3- 3 Pressure and Temperature values for vertical well reservoir

Cell	Region	Z (boundary)	Z (center)	T (center)	T (boundary)	P (boundary) Mpa	P (center) Mpa
		0		280.8		7.68	
1	Shale	33.751	16.875	281.813	281.306	8.011	7.845
2	Shale	56.314	45.032	282.489	282.151	8.232	8.121
3	Shale	71.397	63.855	282.942	282.716	8.379	8.305
4	Shale	81.48	76.439	283.244	283.093	8.478	8.429
5	Shale	88.221	84.851	283.447	283.346	8.544	8.511
6	Shale	92.727	90.474	283.582	283.514	8.588	8.566
7	Shale	95.74	94.234	283.672	283.627	8.618	8.603
8	Shale	97.754	96.747	283.733	283.702	8.637	8.628
9	Shale	99.1	98.427	283.773	283.753	8.651	8.644
10	Shale	100	99.385	283.804	283.795	8.659	8.654
11	Shale	100.9	100.45	283.827	283.814	8.668	8.664
12	Shale	101.8	101.35	283.854	283.841	8.677	8.673
13	Shale	102.7	102.25	283.881	283.868	8.686	8.681
14	Shale	103.6	103.15	283.908	283.895	8.695	8.69
15	Shale	104.5	104.05	283.935	283.922	8.703	8.699
16	Shale	105.4	104.95	283.962	283.949	8.712	8.708
17	Shale	106.3	105.85	283.989	283.976	8.721	8.717
18	Shale	107.2	106.75	284.016	284.003	8.73	8.725
19	Shale	108.1	107.65	284.043	284.03	8.739	8.734
20	Shale	109	108.55	284.07	284.057	8.747	8.743
21	Shale	109.9	109.45	284.097	284.084	8.756	8.752
22	Shale	110.8	110.35	284.124	284.111	8.765	8.761
23	Shale	111.7	111.25	284.151	284.138	8.774	8.77
24	Shale	112.6	112.15	284.178	284.165	8.783	8.778
25	Shale	113.5	113.05	284.205	284.192	8.792	8.787
26	Shale	114.4	113.95	284.232	284.219	8.8	8.796
27	Shale	115.3	114.85	284.259	284.246	8.809	8.805
28	Shale	116.2	115.75	284.286	284.273	8.818	8.814
29	Shale	117.1	116.65	284.313	284.3	8.827	8.822
30	Shale	118	117.55	284.34	284.327	8.836	8.831
31	Shale	118.9	118.45	284.367	284.354	8.844	8.84
32	Shale	119.8	119.35	284.394	284.381	8.853	8.849
33	Shale	120.7	120.25	284.421	284.408	8.862	8.858
34	Shale	121.6	121.15	284.448	284.435	8.871	8.866
35	Shale	122.5	122.05	284.475	284.462	8.88	8.875
36	Shale	123.4	122.95	284.502	284.489	8.888	8.884
37	Shale	124.3	123.85	284.529	284.516	8.897	8.893
38	Shale	125.2	124.75	284.556	284.543	8.906	8.902
39	Shale	126.1	125.65	284.583	284.57	8.915	8.911
40	Shale	127	126.55	284.61	284.597	8.924	8.919
41	Hydrate	127.9	127.45	284.637	284.624	8.933	8.928
42	Hydrate	128.8	128.35	284.664	284.651	8.941	8.937
43	Hydrate	129.7	129.25	284.691	284.678	8.95	8.946
44	Hydrate	130.6	130.15	284.718	284.705	8.959	8.955
45	Hydrate	131.5	131.05	284.745	284.732	8.968	8.963

Cell	Region	Z (boundary)	Z (center)	T (center)	T (boundary)	P (boundary) Mpa	P (center) Mpa
46	Hydrate	132.4	131.95	284.772	284.759	8.977	8.972
47	Hydrate	133.3	132.85	284.799	284.786	8.985	8.981
48	Hydrate	134.2	133.75	284.826	284.813	8.994	8.99
49	Hydrate	135.1	134.65	284.853	284.84	9.003	8.999
50	Hydrate	136	135.55	284.88	284.867	9.012	9.007
51	Hydrate	136.9	136.45	284.907	284.894	9.021	9.016
52	Hydrate	137.8	137.35	284.934	284.921	9.029	9.025
53	Hydrate	138.7	138.25	284.961	284.948	9.038	9.034
54	Hydrate	139.6	139.15	284.988	284.975	9.047	9.043
55	Hydrate	140.5	140.05	285.015	285.002	9.056	9.052
56	Hydrate	141.4	140.95	285.042	285.029	9.065	9.06
57	Hydrate	142.3	141.85	285.069	285.056	9.074	9.069
58	Hydrate	143.2	142.75	285.096	285.083	9.082	9.078
59	Hydrate	144.1	143.65	285.123	285.11	9.091	9.087
60	Hydrate	145	144.55	285.15	285.137	9.1	9.096
61	Shale	145.9	145.45	285.177	285.164	9.109	9.104
62	Shale	147.246	146.573	285.217	285.197	9.122	9.115
63	Shale	149.26	148.253	285.278	285.248	9.142	9.132
64	Shale	152.273	150.766	285.368	285.323	9.171	9.156
65	Shale	156.779	154.526	285.503	285.436	9.215	9.193
66	Shale	163.52	160.149	285.706	285.604	9.281	9.248
67	Shale	173.603	168.561	286.008	285.857	9.38	9.331
68	Shale	188.686	181.145	286.461	286.234	9.528	9.454
69	Shale	211.249	199.968	287.137	286.799	9.749	9.638
70	Shale	245	228.125	288.15	287.644	10.079	9.914

Discretization of the Grid:

r-direction:

There are 80 cells distributed logarithmically from $r = r_w = 0.111\text{m}$. (r_w = well bore radius) to $r = 450\text{m}$. The radius of the individual cells is given in Table 3-3.

Table 3- 4 Radius of individual cells

Cell	Radius, m	Cell	Radius, m	Cell	Radius, m	Cell	Radius, m
r1	0.131	r21	1.414	r41	10.287	r61	71.627
r2	0.153	r22	1.567	r42	11.340	r62	78.906
r3	0.177	r23	1.735	r43	12.500	r63	86.923
r4	0.204	r24	1.919	r44	13.777	r64	95.755
r5	0.233	r25	2.123	r45	15.184	r65	105.482

r6	0.266	r26	2.347	r46	16.734	r66	116.198
r7	0.302	r27	2.594	r47	18.442	r67	128.000
r8	0.341	r28	2.866	r48	20.322	r68	141.001
r9	0.384	r29	3.166	r49	22.394	r69	155.321
r10	0.432	r30	3.496	r50	24.675	r70	171.095
r11	0.485	r31	3.859	r51	27.188	r71	188.469
r12	0.543	r32	4.260	r52	29.957	r72	207.607
r13	0.606	r33	4.701	r53	33.006	r73	228.688
r14	0.677	r34	5.187	r54	36.365	r74	251.909
r15	0.754	r35	5.722	r55	40.065	r75	277.486
r16	0.839	r36	6.311	r56	44.140	r76	305.659
r17	0.933	r37	6.961	r57	48.629	r77	336.692
r18	1.037	r38	7.676	r58	53.573	r78	370.874
r19	1.151	r39	8.464	r59	59.020	r79	408.526
r20	1.276	r40	9.331	r60	65.019	r80	450.000

z-direction: The hydrate bearing zone is uniformly discretized and the upper and lower shale zones are logarithmically discretized. In both of these shale zones, the first grid block (next to the hydrate zone) is the same size as those in the hydrate bearing zone (0.9 m). For each subsequent cell, the dz obeys $dz_i = dz_{i-1} * 1.49587$ (as one moves away from the hydrate zone). This leads to the following z values given in Table 3-4

Table 3- 5 Discretization of the grid in z direction.

Cell number	dz	z (boundary)	z (center)
1	0.900	0.900	0.450
2	1.346	2.246	1.573
3	2.014	4.260	3.253
4	3.012	7.273	5.766
5	4.506	11.779	9.526
6	6.741	18.520	15.149
7	10.083	28.603	23.561
8	15.083	43.686	36.145
9	22.563	66.249	54.968
10	33.751	100.000	83.125

Boundary conditions, initial conditions and all other properties are similar to those used in section 3.1. The simulations are carried over a time period of 50 years. Data for gas production rate, water production rate, cumulative gas production and cumulative water production is recorded with a time step of 0.001 days for 50 years.

3.3 Results

The simulations were carried out using CMG STARS. For the horizontal slice, in order to integrate the results obtained for the entire reservoir, the rates are multiplied by a factor of 450π . This factor is worked out from the fact that the reservoir is 450 m thick in the *j-direction* and that it is being compared to a cylindrical system. The ratio of their volumes is π . For this scaling up, the pressure drop across the horizontal well is neglected as it is expected that pressure drop along the horizontal fracture will be much lesser than in a vertical well.

Figure 3-6 shows gas rates of the two reservoirs. The reservoir with horizontal well yielded quicker and higher gas rates at earlier times. This can be attributed to the quicker depressurization in the horizontal well. Figure 3-7 shows the cumulative gas rates of both the reservoirs. Much higher water rates are obtained in the horizontal well case than that in the vertical well case. The higher water removal causes higher depressurization of the reservoir and enhances gas production due to the pressure gradient in the reservoir.

Figure 3- 6 Gas Rate obtained from both cases, Million cubic meters/day

Figure 3-7 Cumulative gas production for both cases, Million cubic meters

Figure 3-8 shows water rate obtained in both the reservoirs. The reservoir with horizontal well yielded more water over the simulation time as seen in Figure 3-9. This shows it was easily depressurized.

Figure 3- 8 Water rate in both cases, cubic meters/day

Figure 3- 9 Cumulative water production, million cubic meters

3.4 Economics

Figures 3-10 and 3-11 show the cumulative cash flow diagrams for the vertical well and the horizontal well respectively. The vertical well reservoir breaks even using a wellhead of \$7/MCF at 6 years and a 15% discount rate and after 6 years at 17% and 19% discount rates. For a project life of 20 years, the wellhead breakeven price is \$7.51/MCF.

The reservoir with horizontal well breaks even after 1 year at \$7.00/MCF and at discount rates 15%, 17% and 19%. For a project life of 20 years, the wellhead breakeven price is about \$2.87/MCF. The breakeven price for the vertical well was obtained as \$7.51/MCF.

Figure 3- 10 Cumulative cash flow diagram for reservoir with vertical well

Figure 3- 11 Cumulative cash flow diagram for reservoir with horizontal well

From these results, it can be stated that horizontal wells would likely provide much higher rates of gas production from hydrate reservoirs than vertical wells at earlier times. However, the economics are largely dependent on the capital, operating and maintenance costs of these wells. The economic details used in this chapter are given in Chapter 2.

4. Economic Analysis of a Plackett-Burman Sensitivity Analysis

The objective of this study is to enumerate the effects of reservoir parameters on economics using a previously performed Plackett-Burman design³⁶. In the previous study sensitivity analysis is performed for seven reservoir parameters pressure, temperature, hydrate saturation, permeability, bottom-hole pressure, porosity and free water saturation. Cases have been simulated with increased and decreased values of the parameters and the results are compared³⁵. The objective of this work is to perform an economic analysis of the Plackett-Burman analysis.

There are many universally accepted procedures for conducting sensitivity analysis; a common approach is to explore the effects of changing parameters one at a time on the production rates. For the sensitivity analysis, seven factors were chosen. Here, the Plackett-Burman (P-B) design has been used which will be discussed in the later part of the document. The economics of each situation will be quantified by breakeven price calculated based on the production and this breakeven price is attributed like the outputs from the model for the given input factors.

4.1 The Numerical Simulation Code

The sensitivity studies in this work are conducted using STARS⁴² (Steam, Thermal and Advanced Process Reservoir Simulator) simulator developed by Computer Modeling Group (CMG). STARS can model the flow of three-phase, multi-component fluids using Cartesian cylindrical or mixed coordinates. The input parameters to the model can be in the forms of field data or they are generated by correlations built into the model. STARS is designed to stimulate a variety of complex oilfield production and enhancement

processes; however, it is primarily used for conventional black oil studies. To simulate gas production by hydrate dissociation STARS needs to make adjustments to accommodate the properties of hydrate. In this study, hydrate is considered as the oil phase with very high viscosity and low relative permeability.

The base case problem originates from Prudhoe Bay L-Pad 106 site³⁸ in Alaska. The geographical location is shown in Figure 4-1. The base case problem is adapted from the International Methane Hydrate Code Comparison Project. The base case is the reservoir model used in Case 2 described in Chapter 2. The reservoir parameters are given here in Table 4-1.

Figure 4-1 Gas hydrate deposits in the North Slope of Alaska.

Figure 4-2 Geometric representation of the reservoir grid

Table 4-1 Reservoir parameters in the base case problem.

Property	Value
Permeability, mD	Shale - 0.0 Hydrate layer - 1000 (r direction) Hydrate layer - 100 (z direction)
Porosity, %	Shale - 10 Hydrate zone - 35
Pore Compressibility (1/Pa)	1.00E-08
Bulk Density(kg/m ³)	1.86E+03
Rock Density (kg/m ³)	2650
Rock Specific Heat (J/kg/K)	1000
Grain specific heat (J/kg/K)	750
Bulk Specific Heat (J/kg/K)	525
Initial saturations	shale - $S_w = 1.0$ HBZ - $S_H=70\%$, $S_w = 30\%$
Initial Bottom Hole Pressure	2700 kPa
Initial pressure (at uppermost layer of HBZ)	7327 kPa
Capillary pressure Model	$\bar{S}_w = \frac{S_w - S_{wir}}{1 - S_{wir}} = \left[1 + (\alpha \beta_{gl} h_{gl})^n \right]^{-m}$
α	10.204 1/m
β_{gl}	1
S_{wir}	0.28
n	4.432
Aqueous rel Perm model	$k_{rw} = \left\{ \frac{(S_w - S_{wir})}{(1 - S_{wir})} \right\}^{4.52}$
S_{wir}	0.248
Gas rel Perm model	$k_{rg} = \left\{ \frac{(S_G - S_{Gir})}{(1 - S_{wir})} \right\}^{3.16}$
S_{Gir}	0
S_{wir}	0

4.2 The Plackett-Burman design

The Plackett-Burman design is an alternative to the complete factorial design which requires 2^n runs, where n is the number of parameters and “2” is a consequence of using 2 values (high, low) for each parameter. To perform one complete factorial design in this problem, a cumbersome 128 (2^7) runs would need to be conducted.

The P-B design specifies a subset of scenarios used for a complete factorial design. The number of scenarios for the design is 2 times the smallest multiple of 4 that is greater than the number of parameters. In this case 16 runs are conducted for seven reservoir parameters. Upper or lower values for each parameter are selected based on the Plackett-Burman sensitivity analysis (PBSA) matrix given in Table 3-2. The ‘plus’ and the ‘minus’ in the matrix represents higher and lower values for each run. These values are obtained by increasing and decreasing the value of the parameter by certain fixed percentage in order to gain maximum benefit from this design. A total of 16 runs are conducted for each design by changing the seven parameters for every run in the fashion of the PBSA matrix. All other variables are same as in the base case problem. Hydrate saturation, water saturation, free water saturation and irreducible water saturation are linked together by the following equations.

$$S_w + S_H = 1, S_G = 0 \text{ (initially)}, S_{irw} = S_w - S_{free}$$

Eight different reservoir scenarios are considered in this study. The seven reservoir parameters with their higher and lower values for Scenario 1 are shown in Figure 4-3. The values of the parameters for eight different designs are tabulated in Table 3-3.

Pressure and Temperature values specified are for the uppermost part of the shale zone and the gradients are the same as those of the base case.

Table 4-2 Plackett-Burman sensitivity analysis matrix

Run Number	Pressure	Temperature	Hydrate Saturation	Permeability	Bottom hole Pressure	Porosity	Free water
1	+	+	+	-	+	-	-
2	-	+	+	+	-	+	-
3	-	-	+	+	+	-	+
4	+	-	-	+	+	+	-
5	-	+	-	-	+	+	+
6	+	-	+	-	-	+	+
7	+	+	-	+	-	-	+
8	-	-	-	-	-	-	-
9	-	-	-	+	-	+	+
10	+	-	-	-	+	-	+
11	+	+	-	-	-	+	-
12	-	+	+	-	-	-	+
13	+	-	+	+	-	-	-
14	-	+	-	+	+	-	-
15	-	-	+	-	+	+	-
16	+	+	+	+	+	+	+

Figure 4-3 Schematic of the grid and its seven reservoir parameters

Table 4-3 Parameter specifications for different scenarios

Parameters	Scenario 1		Scenario 2		Scenario 3		Scenario 4	
Pressure (kPa)	7782	6513	5243	6513	5878	6513	5878	6513
Temperature (°C)	3.306	2.506	1.706	2.506	2.306	2.506	7.391	8.157
Hydrate Sat.	0.8	0.75	0.5	0.75	0.65	0.75	0.65	0.75
Permeability (mD)	1500/150	1000/100	500/50	1000/100	750/75	1000/100	750/75	1000/100
BHP (kPa)	3500	2700	2700	3000	2700	2900	2700	2900
Porosity	0.5	0.4	0.3	0.4	0.3	0.4	0.3	0.4
Free Water	0.2	0.15	0.1	0.15	0.12	0.15	0.12	0.15

Table 4-3 (contd...)

Parameters	Scenario 5		Scenario 6		Scenario 7		Scenario 8	
Pressure (kPa)	7148	6513	7148	6513	5878	6513	7148	6513
Temperature (°C)	8.92	8.157	5.56	5.11	4.65	5.11	8.92	8.157
Hydrate Sat.	0.8	0.75	0.8	0.7	0.6	0.7	0.5	0.4
Permeability (mD)	1250/125	1000/100	1250/125	1000/100	750/75	1000/100	1250/125	1000/100
BHP (kPa)	2900	2700	3000	2900	2700	2900	2900	2700
Porosity	0.5	0.4	0.5	0.4	0.3	0.4	0.4	0.3
Free Water	0.18	0.15	0.18	0.15	0.12	0.15	0.18	0.15

Simulations were run using CMG STARS for 20 years. The project life time for evaluating the economics is 20 years.

4.3 Results

Scenarios 1-3 did not produce as much gas owing to low reservoir temperatures. Scenarios 4-8 were warmer reservoirs and produced significantly higher amounts of gas leading to better economics. Scenario 1 resulted in very high prices. The best Scenario was Scenario 8. The wellhead breakeven prices for all the Scenarios and runs can be seen in Table 3-4. Production curves for all the designs are given in Appendix II. Figure 3-4 shows the spread of breakeven prices in each design.

Table 4-4 Breakeven prices in different cases of the PB design (expressed in \$/MMBTU)

Run	Scenario 1	Scenario 2	Scenario 3	Scenario 4	Scenario 5	Scenario 6	Scenario 7	Scenario 8
1	210.31	77.57	24.04	4.54	4.39	7.23	6.85	4.05
2	15.28	18.45	17.42	4.47	4.35	7	6.46	3.97
3	156.93	48.2	16.93	4.49	4.4	6.75	6.27	4.04
4	26.11	45.39	83.17	4.92	4.73	7.81	7.58	4.21
5	13.13	29.62	23.39	4.74	4.53	7.16	7.23	4.11
6	27.65	106.95	27.37	5.06	4.77	8.64	7.73	4.18
7	5.14	8.55	9.7	4.11	4.06	5.61	5.22	3.95
8	16.63	24.71	14.04	4.57	4.42	6.77	6.37	4.15
9	11.94	17.04	14.16	4.57	4.46	6.85	6.37	4.06
10	123.59	43.07	20.44	4.67	4.52	6.93	6.73	4.19
11	16.8	24.79	20.8	4.7	4.48	7.36	7.03	4.11
12	10.4	18.89	14.58	4.32	4.21	6.32	5.85	3.94
13	21.77	41.37	14.96	4.45	4.35	6.68	6.12	4.01
14	37.31	13.37	13.25	4.25	4.2	5.95	5.76	4.03
15	10594.2	318.83	53.04	5.41	5.02	9.47	9.2	4.15
16	72.29	33.32	29.27	4.57	4.44	7.23	6.73	4.01

Figure 4-4 Box plot of breakeven prices for each Scenario

Figure 4- 5 Box plot Scenarios 4-8 in more detail

The most economic scenario was found out to be scenario 8 since it was more productive, owing to the warmer reservoir settings and optimum hydrate saturation. Hydrate saturation that was very high (70% or higher) showed a negative impact on production as hydrate dissociation is endothermic and the cooled reservoir inhibited the further dissociation of hydrate. The Scenarios 1 through 3, being cold reservoirs, were unable to produce as much gas.

4.3.1 Effects based on breakeven prices

For all the runs, the breakeven prices are calculated and the effects of parameters on the breakeven prices are determined. Equation is used to calculate the effect power of a parameter, j . A higher power means more correlation. Positive power ' j ' means positive correlation (as the parameter increases, the breakeven price increases) and negative ' j '

means negative correlation (negative correlation is good in this study as lesser breakeven price is better).

eqn. (3)

Where B_n is the breakeven price for each run $j = 1, 2 \dots 8$. '+' is taken before the B_n when there is a corresponding '+' in the matrix column for that specific parameter and '-' is taken before the B_n when there is a corresponding '-' in the matrix column for that specific parameter.

The effects of the reservoir parameters on breakeven prices are studied. Points above the y-axis indicate that as the variable increases, price increases. Below y-axis, the points represent negative effects, i.e., as the variable increases, prices decrease.

Figure 4-5 Effects of reservoir variables on breakeven prices for Scenarios 1-3

Figure 4-6 Effects of reservoir variables on breakeven prices for Scenarios 4-8

The breakeven prices were found out to be the most sensitive to the reservoir temperature and bottom-hole pressure upon production. Among seven parameters studied, temperature has the highest negative (-) effect on production rates while bottom hole pressure has the highest positive (+) effect on breakeven prices which means as temperature increases, the breakeven price decreases. Other parameters such as rock permeability and free water saturation showed a positive correlation to the production, while hydrate saturations above 60% have a negative impact on production rates. Hydrate saturations of approximately 40-50% show a positive impact on gas production rates and so negatively impact on the prices. The most economic scenario was found to be Scenario 8 since it was more productive owing to the warmer reservoir settings and optimum (40-50%) hydrate saturation. Scenarios 1–3 produced much less gas over the 20-yr lifetime of

the well due to the low initial reservoir temperatures. The lowest breakeven price obtained was \$3.95 for Run 7 of Scenario 8. Run #7 has higher temperatures and high permeabilities in every scenario leading to higher gas productivity.

5. Sensitivity Analysis of hydrate bearing reservoirs: Stochastic sampling of input parameters

The objective of this study is to estimate the uncertainty in production rates at hydrate-bearing reservoirs that could arise from the uncertainty in the reservoir parameters. One hundred reservoirs were modeled based on data distributions adapted from wire-line log data obtained from Mt. Elbert stratigraphic test well²⁹ on the Alaskan North Slope. The geologic architecture used for the model is taken from Case 3 of Chapter 2. In this study, a Monte Carlo method of sensitivity analysis is conducted by inputting reservoir properties from a pre-determined range of values with a specific mean and standard deviation. These statistics of the input variables are adapted from the Mt. Elbert stratigraphic test well data and the range is decided by engineering judgment. Hydrate saturation, permeability, porosity and free water saturation will be the parameters included as Monte Carlo simulation variables. All of the 100 reservoirs are also modeled with a constant bottom hole well pressure of 2700 kPa as lower BHPs caused ice formation in the system.

5.1 Introduction to Monte Carlo methods

Monte Carlo⁴³ (MC) methods can be described as statistical simulation methods, where statistical simulation is defined as any method that utilizes sequences of random numbers to perform the simulations. Statistical simulation methods can be different from conventional numerical discretization methods, which generally are applied to ODEs and PDEs that describe some underlying physical or mathematical system. In many applications of Monte Carlo, the physical process is simulated directly, and there is no

need to even write down the differential equations that describe the behavior of the system. The only requirement is that the physical (or mathematical) system be described by probability density functions (PDF) and MC simulation can proceed by random sampling from the PDFs. Many simulations (or trials) are then performed and the desired result is taken as an average over the number of observations (which may be a single observation or perhaps millions of observations). In many practical applications, one can predict the statistical error (the variance) in this average result, and hence an estimate of the number of Monte Carlo trials that are needed to achieve a given error. Schematic representation uncertainty propagation in a Monte Carlo simulation is shown in Figure 5-1.

Figure 5- 1 Schematic of uncertainty propagation in MC analysis

Monte Carlo simulation is a method for iteratively evaluating a deterministic model using sets of random numbers as inputs. This method is often used when the model is complex, nonlinear, or involves more than just a couple uncertain parameters. The Monte Carlo method is just one of many methods for analyzing uncertainty propagation. The aim of the method is to determine how random variation or error affects the sensitivity, and performance of the system being modeled. Monte Carlo simulation is categorized as a sampling method because the inputs are randomly generated from probability distributions to simulate the process of sampling from an actual population. So, it is tried to choose a distribution for the inputs that most closely matches data we already have, or best represents our current state of knowledge. The data generated from the simulation can be represented as probability distributions (or histograms).

The Economics of each situation will be quantified by breakeven price calculated based on the production and this breakeven price is the effect that is considered due to the variables hydrate saturation, permeability, bottom-hole pressure, porosity and free water saturation.

5.2 The simulation model: Simulator used.

The sensitivity studies in this study are conducted using STARS⁴² (Steam, Thermal and Advanced Process Reservoir Simulator) simulator developed by Computer Modeling Group (CMG). STARS can model the flow of three-phase, multi-component fluids using Cartesian, cylindrical or mixed coordinates. The input parameters to the model can be in the forms of field data or they are generated by correlations built into the model. STARS is designed to stimulate a variety of complex oilfield production and enhancement

processes; however, it is primarily used for conventional black oil studies. To simulate gas production by hydrate dissociation STARS needs to make adjustments to accommodate the properties of hydrate. In this study, hydrate is considered as the oil phase with very high viscosity and low relative permeability.

5.3 Input Variables and Method followed

Figure 5-2 shows the process followed for data selection and reservoir creation. The distribution of actual data and the sampled data will be discussed in this section.

Figure 5-2 Flowchart showing the Data-Selection and Reservoir Creation process

The reservoir model's input variables are hydrate saturation, water saturation, free water saturation, porosity and permeability. Each reservoir model is simulated using CMG STARS and resulting water production and gas production are recorded from which the breakeven price would later be calculated as the effect of these input variables.

Hydrate saturation: Hydrate saturation is the relative amount of hydrate in the pores of a medium usually as a percentage of volume. As hydrate saturation increases, it is typically expected that the productivity of the reservoir increases. However as a previous study found higher hydrate saturation can actually yield lower gas production⁴. For this experiment, 100 values are randomly sampled from the available Mt. Elbert Stratigraphic test well data. The mean and standard deviation of the actual and sampled data and the distributions are shown in Figure 5-3.

Figure 5- 3 Distribution of hydrate saturation of actual and sampled data

Permeability: Permeability is the ability of a rock or medium to transmit fluids. Effective permeability is the ability to transport a particular fluid in the presence of other immiscible fluids in the reservoir. Relative permeability is the ratio of effective permeability of a particular fluid at a particular saturation to absolute permeability of that fluid at total saturation. Figure 5-4 shows the distribution of permeability in actual and sampled data. It also shows the mean and standard deviation of the actual and sampled data.

Figure 5- 2 Distribution of permeability of actual and sampled data

Water Saturation: Water saturation is the fraction of water in a given pore space. Water saturation follows the equation $S_H + S_G + S_W = 1$, where S_H is the hydrate saturation, S_G is the gas saturation and S_W is the water saturation. There is no gas initially in the reservoir. So the distribution of water saturation is directly dependent on the hydrate saturation

distribution. It is equal to a value of $(1 - S_H)$. Figure 5-5 shows the statistics and distribution of water saturation values of the actual and sampled data.

Figure 5- 5 Distribution of water saturation of actual and sampled data

Porosity: Porosity is the void space in a rock or medium. It is the interconnected pores in the medium that allow the medium to have permeability to fluids. It is generally thought that higher porosity gives high production rates due to more available pore volume in the reservoir. However it depends on the value of porosity chosen. There is a lot of uncertainty associated with porosity changes⁴. Figure 5-6 gives the distribution of porosity of the actual and sampled data.

Free water saturation: Irreducible water saturation is the minimum possible saturation of water in a rock or medium. It is also referred to as connate water saturation. It is the lowest water saturation, S_{wi} , that can be achieved in a core plug by displacing the water

by oil or gas. Free water saturation is the difference between water saturation in a rock and its irreducible water saturation. Permeability is affected by changing irreducible water saturation. So, irreducible water saturation and free water saturation are both important factors to be considered during a reservoir study. Figure 5-7 gives the distribution of free water saturation in actual and sampled data.

Figure 5-6 Distribution of porosity of actual and sampled data.

Figure 5- 7 Distribution of free water saturation of actual and sampled data

Table 5-1 shows the descriptive statistics of the input variables used. 100 different reservoir models were prepared for the analysis. Each set of input data is simulated using CMG STARS for output variables such as gas production and water production from which the breakeven price would be later calculated as the effect of these input variables.

Table 5- 1Descriptive statistics for the various input variables used in the simulations

Variable	Mean	St. Dev	Minimum	Maximum	N
Hydrate Saturation	0.5603	0.1982	0.0732	0.9482	100
Water Saturation	0.4417	0.1953	0.9268	0.0518	100
Porosity	0.3490	0.0321	0.2507	0.4340	100
Permeability	869.5	437.1	50.9	1918.3	100
Free Water saturation	0.1549	0.0278	0.0176	0.1898	100

5.4 Results

The factors that are analyzed are hydrate saturation, water saturation, porosity, permeability and free water saturation. The simulations of the models yielded a varied range of production rates. This can be seen in Figure 5-8. The response factor which will be called ‘effect’ in this document is the wellhead breakeven price for each production curve. Figure 5-8 shows how variant the outcome can be from similar reservoir settings by varying some input parameters.

Figure 5- 3 Cumulative Production curves obtained from CMG STARS for the 100 reservoir models

Figure 5-9 shows a scatter plot of all the effects calculated. Some unusually high values arising from very low hydrate saturation have been omitted from the analysis. Detailed spreadsheet of the effects data is given in Appendix III. These arrays of input parameters used yielded an output model with a mean of \$36.77 and standard deviation of \$37.01.

Figure 5-9 Scatter Plot of the effects of the runs considered for analysis

Figure 5- 10 Histogram of effects, breakeven prices

Regression Analysis:

Regression was performed using Minitab 15⁴⁵

The regression equation is

Effects, BEP = - 66 + 129 Hydrate Sat. MC + 17 Water Sat. MC + 216 Porosity MC
- 0.0375 Permeability, mD MC - 106 Free Water Sat. MC

Predictor	Coef	SE Coef	T	P
Constant	-65.7	151.2	-0.43	0.665
Hydrate Sat. MC	128.9	140.7	0.92	0.362
Water Sat. MC	16.8	143.0	0.12	0.907
Porosity MC	216.05	91.16	2.37	0.020
Permeability, mD MC	-0.037466	0.006941	-5.40	0.000
Free Water Sat. MC	-106.4	130.9	-0.81	0.419

S = 27.4388   R-Sq = 49.7%   R-Sq(adj) = 46.8%

Correlation:

Table 5-2 gives the correlation coefficients obtained between each of the parameters. The correlation was also calculated using Minitab 15. A positive correlation coefficient means that as one factor increases, the corresponding factor increases and a negative correlation coefficient means as the factor increases, the corresponding factor decreases. It is important to note that correlation does not imply causality. Only properly controlled experiments enable the determination whether a relationship is causal. In the data presented in Table 5-2, the correlation coefficients might imply that

- As Permeability and Free water saturation increase, Breakeven price tends to decrease. However, the P-value of *Free water saturation-Effects, BEP* is higher than 0.05 (the default α value) because of which it cannot be asserted that they have a linear relationship

- Hydrate saturation and Porosity do not have a direct linear relationship. More experiments are required to calculate the effect of these factors on the breakeven prices.

Table 5- 2 Table of correlation coefficients

	Hydrate Saturation	Water Saturation	Porosity	Permeability,mD	Free Water Saturation
Water Saturation	-0.995 0				
Porosity	-0.021 0.838	0.022 0.832			
Permeability, mD	0.083 0.411	-0.08 0.431	-0.049 0.632		
Free Water Saturation	-0.236 0.018	0.227 0.023	-0.015 0.879	0.015 0.886	
Effects, BEP	0.519 0	-0.514 0	0.24 0.022	-0.333 0.001	-0.084 0.43
Pearson Coefficient					
P-Value					

The base case of this experiment is Problem 7c of the DOE Code Comparison project. Its breakeven price (effect) calculated was about \$7.00. The 5th percentile (P-5) is that value which marks off the lowest 5 per cent of the observations from the rest, the 50th percentile (P-50) is the same as the median, and the 95th percentile (P-95) exceeds all but 5 per cent of the values. The P-5 of this distribution is about \$6.97, P-50 is \$18.30 and P-

95 is \$107.97. Figure 5-10 shows a frequency histogram of the effects data. There are some extremely high effects which arise from very low producing reservoirs.

The 5th percentile and not 50th percentile of this experiment is close to the base case's breakeven price. It is because the effects between the reservoir parameters were not taken into consideration. Hydrate Saturation, Porosity, water saturation, permeability and free water saturation are all interdependent and highly localized. So, there is a lot of difference between the base case scenario and the P-50 of the experiment conducted. Further analysis is recommended taking into view the thorough lithology of the reservoir.

6. Conclusions and Future Work

6.1 Conclusions

Economic Evaluations for problem 7 (referred to as Cases 1, 2 & 3 in Chapter 2) of the DOE Code Comparison Study are carried out using NPV, IRR and Breakeven analyses. Problem 7C (Case 3) was found out to be the most commercially viable site of the cases in Problem 7 as it was warmer and deeper than other cases.

For similar reservoir descriptions, simulations were carried out using CMG STARS by incorporating a horizontal and a vertical well in comparable reservoirs and their results were evaluated against each other. The reservoir completed with a horizontal well showed higher production rates at earlier times. The wellhead prices for equivalent horizontal well and vertical well completions were calculated to be \$2.87 and \$7.51 per mscf respectively.

Sensitivity analysis using L-2 Plackett-Burman Design was carried out to calculate effects of reservoir parameters on wellhead prices. It was found that breakeven wellhead prices were most sensitive to temperature of the reservoir and the bottom hole well pressure. Stochastic sampling of reservoir parameters was performed using the data from Mt. Elbert Stratigraphic test well. It was observed that Bottomhole pressure had a positive correlation with wellhead prices (as BHP increases breakeven prices increase) and permeability had a negative correlation (breakeven prices decrease with increase in permeability) with wellhead prices.

Lowering the Bottomhole pressure as much as possible (but not less than 2700 kPa to avoid ice formation) leads to increase in production rates and better economics as flow of higher depressurization enables more dissociation of gas. Minimum wellhead breakeven obtained was \$6.54/mscf. The Q1 showed a value of about \$11/mscf wellhead breakeven price in this analysis. However, there was a significant difference in the breakeven price obtained from Case 2, chapter 2 and the sensitivity analysis (MC). This is due to varying the reservoir parameters randomly and individually when they are all in fact interrelated.

6.2 Future Work

Economic evaluations must be done for more complex reservoir models that incorporate heterogeneity, multiple wells, and also should set a simulation time of less than 15 years and aim at producing gas quickly through multiple methods of production. A well cost model specifically for hydrate wells needs to be developed taking into consideration the site-specific geology. In future, any financial Monte Carlo simulations on hydrate reservoirs should be done taking into consideration the interrelationship between all the reservoir parameters.

References

1. Kvenvolden, K. A. (1993) *Gas hydrates-Geological Perspective and global change. Reviews of Geophysics* 31, 173-187
2. Humphry Davy, (1811) *Philosophical Transactions of the Royal Society* vol. 101, pp. 155-162
3. Yefremova, A.G. ; Gritchina, N.D., (1981) *Gas hydrates in marine sediments and problem of their practical use* Pages: 32-35
4. Sloan, E., & Koh, C. (2007). *Clathrate hydrates of natural gases*: CRC Press. Pages
5. Kelkar, S., Selim, M., & Sloan, E. (1998). *Hydrate dissociation rates in pipelines. Fluid Phase Equilibria*, 150, 371-382.
6. Sloan, E. (2003). *Fundamental principles and applications of natural gas hydrates. Nature*, 426(6964), 353-363.
7. Sloan, E., & Koh, C. (2007). *Clathrate hydrates of natural gases*: CRC Press. Page 55
8. The Colorado School of Mines website:
<http://inside.mines.edu/~sdec/GasHydrates.html>, last accessed on 9/3/09.
9. Sloan, E., & Koh, C. (2007). *Clathrate hydrates of natural gases*: CRC Press. Page 54
10. McMullan, R., & Jeffrey, G. (1965). *Polyhedral clathrate hydrates. IX. Structure of ethylene oxide hydrate. The Journal of Chemical Physics*, 42, 2725.
11. Mak, T., & McMullan, R. (1965). *Polyhedral clathrate hydrates. X. Structure of the double hydrate of tetrahydrofuran and hydrogen sulfide. The Journal of Chemical Physics*, 42, 2732
12. Ripmeester, J., Tse, J., Ratcliffe, C., & Powell, B. (1987). *A new clathrate hydrate structure.*
13. Sloan, E., & Koh, C. (2007). *Clathrate hydrates of natural gases*: CRC Press. Page 9
14. Michael D. Max, Natural Gas Hydrate: *In Oceanic and Permafrost Environments*, 2000 page 4 & Franks, F. (1973). *Water in crystalline hydrates: aqueous*

solutions of simple nonelectrolytes: Plenum Pub Corp.

15. Kishore Mohanty et al, *Petrophysical Characterization and Reservoir Simulator for Methane Gas Production from Gulf of Mexico Hydrates*, June 2007
16. US Geological Survey, 2000
17. The USGS website: <http://walrus.wr.usgs.gov/globalhydrate/poster.pdf>, last accessed on 9/4/09
18. Kvenvolden, K.A. "Gas Hydrates as a Potential Energy Resource", U.S. Geological Survey Professional Paper 1570, pg.555-561, 1993
19. Tofimuk, A.A., Cherskiy, N.V., Tsarev, V.P., *Future Supply of Nature-Made Petroleum and Gas* (Meyer, R.F.,ed.), Pergamon Press, New York, 919 (1977)
20. Energy Information Administration, *Annual Energy Outlook 2009*
21. Marquita Kaya Hill, *Understanding environmental pollution*, page 443
22. Gudmundsson, J.S. et al, *Proceedings of the 2nd ICGH, France*, 1996: 415
23. US EPA, *Climate Change Science an Analysis of Some Key Questions*, 2001
24. Erwin Suess et al, *Flammable Ice*, *Scientific American* November 2009
25. Energy Information Administration, *Annual Energy Outlook 2008*
26. M. D. Max and A. Lowrie, *Oceanic Methane Hydrates: A "Frontier" Gas Resource* *Journal of Petroleum Geology* Volume 19 (1996)
27. Michael D. Max et al. (eds.), *Economic Geology of Natural Gas Hydrate*, 191-206. © 2006 Springer. Printed in the Netherlands.
28. Ann Cook and David Goldberg, *Stress and gas hydrate-filled fracture distribution, Krishna-Godavari basin, India. Proceedings of the 6th International Conference on Gas Hydrates (ICGH 2008), Vancouver, British Columbia, CANADA, July 6-10, 2008.*
29. Anderson, B., et al. *Analysis of Modular Dynamic Formation Test Results from the "Mount Elbert" Stratigraphic Test Well, Milne Point, Alaska.* in *Proceedings of the 6th International Conference on Gas Hydrates*. 2008. Vancouver, British Columbia, Canada.
30. Yamamoto, K.; Dallimore, S. R. *Overview of the 2006-2008 JOGMEC/NRCan/Aurora Mallik Gas Hydrate Production Test Program*, 2008: *American Geophysical Union*

31. J.J. Kollé and M.D. Max, (2000) *Seafloor drilling of the hydrate economic zone for exploration and production of methane*, Tempress Technologies Inc.,
32. E. Suess et al, *Gas hydrate destabilization: enhanced dewatering, benthic material turnover and large methane plumes at the Cascadia convergent margin*, *Earth and Planetary Science Letters* Volume 170, Issues 1-2, 30 June 1999, Pages 1-15
33. Swinkels, W., & Drenth, R. J. J. (2000). *Thermal reservoir simulation model of production from naturally occurring gas hydrate accumulations*.
34. Wilder, J. et al. An International Effort to Compare Gas Hydrate Reservoir Simulators. *Proceedings of the 6th International Conference on Gas Hydrates, July 6-10 2008, Vancouver, British Columbia*.
35. M Gaddipati *Code Comparison of Methane Hydrate Reservoir Simulators using CMG STARS*, - 2008 - West Virginia University
36. Diane L. Beres and Douglas M. Hawkins.,” *Plackett-Burman technique for sensitivity analysis of many-parameterd models*” *Ecological Modeling* 141 (2001) 171-183
37. Moridis, G.J., et al. 2008. *The Use of Horizontal Wells in Gas Production From Hydrate Accumulations. Proceedings of the 6th International Conference on Gas Hydrates, July 6-10 2008, Vancouver, British Columbia*.
38. Wilder, J. et al. *An International Effort to Compare Gas Hydrate Reservoir Simulators. Proceedings of the 6th International Conference on Gas Hydrates, July 6-10 2008, Vancouver, British Columbia*.
39. Stone, H.L., 1970. *Probability model for estimating three-phase relative permeability. Journal of Petroleum Technology* 22 (2), 214–218.
40. Van Genuchten, M., 1980. *A closed-form equation for predicting the hydraulic conductivity of unsaturated soils. Soil Science Society of America Journal* 44, 892–898.
41. Anderson, B.J., et al., *Regional forward production modeling from a single well test, Marine and Petroleum Geology* (2010), doi:10.1016/j.marpetgeo.2010.01.015
42. Computer Modeling Group Ltd, *CMG STARS*. 2009: Calgary, Alberta, Canada.

43. John Michael Hammersley, David Christopher Handscomb '*Monte Carlo methods*' *Chapman and Hall* (1983)
44. 2007 Minitab Inc, Minitab 15 Statistical Software English

Appendix I

Appendix II

S. No.	Hydrate Sat. MC	Water Sat. MC	Porosity MC	Permeability, mD MC	Free Water Sat. MC	Irr. Wat. Sat. MC	Effects, BEP
1	0.8423	0.1577	0.3667	1457.49	0.1377	0.0200	\$ 107.97
2	0.4951	0.5049	0.3196	1283.29	0.1898	0.3151	\$ 11.43
3	0.8298	0.1702	0.3686	1276.59	0.0176	0.1526	\$ 86.23
4	0.2834	0.7166	0.3703	1014.52	0.1538	0.5629	\$ 8.52
5	0.5779	0.4221	0.4069	1035.41	0.1699	0.2522	\$ 12.66
6	0.3493	0.6507	0.3398	564.10	0.1573	0.4935	\$ 17.96
7	0.8422	0.1578	0.3503	939.43	0.1561	0.0017	\$ 146.69
8	0.8056	0.1944	0.3887	1207.63	0.1662	0.0281	\$ 71.70
9	0.3174	0.6826	0.3615	1201.06	0.1301	0.5525	\$ 10.02
10	0.6101	0.3899	0.3117	198.51	0.1444	0.2456	\$ 645.16
11	0.6222	0.3778	0.3384	1809.87	0.1473	0.2305	\$ 15.17
12	0.9398	0.0602	0.3535	248.58	0.0075	0.0527	\$ 1466.64
13	0.1107	0.8893	0.3720	922.44	0.1358	0.7536	\$ 7.50
14	0.6071	0.3929	0.3093	477.27	0.1387	0.2542	\$ 43.56
15	0.1145	0.8855	0.3337	1176.67	0.1731	0.7124	\$ 7.61
16	0.5296	0.4704	0.3884	1229.82	0.1303	0.3401	\$ 18.06
17	0.4485	0.5515	0.3673	154.42	0.1833	0.3682	\$ 82.19
18	0.6215	0.3785	0.3326	1632.39	0.1757	0.2028	\$ 17.27
19	0.7193	0.2807	0.3809	663.04	0.1542	0.1264	\$ 84.42
20	0.6137	0.3863	0.2507	1634.30	0.1709	0.2154	\$ 10.60
21	0.5990	0.4010	0.3601	754.87	0.1584	0.2425	\$ 29.52
22	0.2249	0.7751	0.3368	344.04	0.1319	0.6432	\$ 11.37
23	0.6087	0.3913	0.3506	1383.10	0.1754	0.2159	\$ 17.17
24	0.5343	0.4657	0.3441	896.70	0.1313	0.3344	\$ 19.68

25	0.6380	0.3620	0.3667	757.26	0.1854	0.1766	\$ 34.61
26	0.6789	0.3211	0.3831	916.67	0.1878	0.1333	\$ 36.99
27	0.5052	0.4948	0.3601	877.49	0.1637	0.3311	\$ 17.57
28	0.5039	0.4961	0.3645	1669.87	0.1484	0.3477	\$ 11.90
29	0.7195	0.2805	0.3999	606.07	0.1427	0.1378	\$ 138.12
30	0.7141	0.2859	0.3293	257.28	0.1805	0.1054	\$ 290.92
31	0.4735	0.5265	0.3762	432.75	0.1607	0.3658	\$ 29.81
32	0.7580	0.2420	0.3353	841.40	0.1604	0.0816	\$ 56.48
33	0.4992	0.5008	0.3127	549.19	0.1552	0.3456	\$ 19.46
34	0.4799	0.5201	0.2737	223.86	0.1558	0.3643	\$ 33.90
35	0.6295	0.3705	0.3499	469.53	0.1332	0.2373	\$ 91.95
36	0.4268	0.5732	0.3787	780.37	0.1314	0.4418	\$ 15.50
37	0.7352	0.2648	0.3603	1806.98	0.1549	0.1099	\$ 25.00
38	0.7861	0.2139	0.3629	1256.32	0.1485	0.0654	\$ 62.77
39	0.4992	0.5008	0.3716	1112.70	0.1405	0.3604	\$ 15.55
40	0.0732	0.9268	0.3452	302.84	0.1492	0.7776	\$ 11.62
41	0.6611	0.3389	0.2969	1528.16	0.1594	0.1795	\$ 15.30
42	0.7162	0.2838	0.3442	671.88	0.1582	0.1257	\$ 60.24
43	0.7401	0.2599	0.3396	1382.08	0.1805	0.0794	\$ 26.02
44	0.5904	0.4096	0.3107	1090.42	0.1738	0.2357	\$ 16.12
45	0.3027	0.6973	0.3700	559.43	0.1634	0.5339	\$ 12.14
46	0.5257	0.4743	0.3680	1017.84	0.1636	0.3108	\$ 17.64
47	0.8308	0.1692	0.3084	452.36	0.1673	0.0020	\$ 190.43
48	0.7362	0.2638	0.3817	1393.38	0.1741	0.0896	\$ 58.90
49	0.6604	0.3396	0.3484	903.25	0.1469	0.1926	\$ 1295.79
50	0.7151	0.2849	0.3422	465.04	0.1659	0.1190	\$ 89.46
51	0.8296	0.1704	0.3243	608.59	0.1312	0.0391	\$ 4003.16

52	0.6137	0.3863	0.3011	505.80	0.1311	0.2552	\$ 300.37
53	0.5260	0.4740	0.3184	1918.35	0.1857	0.2884	\$ 9.95
54	0.6694	0.3306	0.3635	639.33	0.1492	0.1814	\$ 60.20
55	0.5363	0.4637	0.3270	1041.18	0.1632	0.3005	\$ 14.73
56	0.2569	0.7431	0.3825	1144.59	0.1460	0.5972	\$ 7.93
57	0.1235	0.8765	0.3107	216.70	0.1770	0.6996	\$ 10.43
58	0.5769	0.4231	0.4024	1012.37	0.1722	0.2509	\$ 25.16
59	0.6544	0.3456	0.3111	853.58	0.1451	0.2005	\$ 30.95
60	0.4558	0.5442	0.3370	537.70	0.1626	0.3817	\$ 19.60
61	0.5436	0.4564	0.3749	1093.47	0.1669	0.2895	\$ 19.79
62	0.7731	0.2269	0.4096	1045.86	0.1356	0.0913	\$ 120.78
63	0.7721	0.2279	0.3801	729.49	0.1576	0.0703	\$ 100.01
64	0.2575	0.7425	0.4004	1098.86	0.1510	0.5915	\$ 7.99
65	0.4237	0.5763	0.3355	719.16	0.1505	0.4257	\$ 13.51
66	0.5220	0.4780	0.3541	538.34	0.1814	0.2966	\$ 29.22
67	0.3864	0.6136	0.3267	1334.29	0.1508	0.4629	\$ 11.62
68	0.4914	0.5086	0.3563	1362.44	0.1369	0.3717	\$ 12.57
69	0.7702	0.2298	0.3271	1226.61	0.1694	0.0604	\$ 24.67
70	0.7882	0.2118	0.2824	519.18	0.1865	0.0254	\$ 62.56
71	0.1480	0.8520	0.3772	554.21	0.1798	0.6722	\$ 6.98
72	0.7686	0.2314	0.3689	548.79	0.1640	0.0674	\$ 14.35
73	0.3538	0.6462	0.3115	1103.00	0.1469	0.4993	\$ 6.54
74	0.7748	0.2252	0.3473	1268.90	0.1609	0.0642	\$ 6.90
75	0.2665	0.7335	0.3428	966.37	0.1580	0.5755	\$ 6.55
76	0.5186	0.4814	0.3635	1055.22	0.1861	0.2953	\$ 6.94
77	0.8689	0.1311	0.3552	663.65	0.1201	0.0110	\$ 8.12
78	0.4502	0.5498	0.3453	786.83	0.1401	0.4097	\$ 9.37

79	0.4501	0.5499	0.3718	1358.36	0.1627	0.3872	\$ 9.02
80	0.6488	0.3512	0.2796	704.80	0.1559	0.1953	\$ 6.87
81	0.6683	0.3317	0.3826	323.58	0.1791	0.1525	\$ 107.15
82	0.5024	0.4976	0.3473	243.90	0.1392	0.3584	\$ 65.02
83	0.5355	0.4645	0.3401	487.29	0.1706	0.2939	\$ 32.11
84	0.9482	0.2518	0.3508	1066.77	0.1222	0.1296	\$ 83.55
85	0.2333	0.7667	0.3046	1173.59	0.1422	0.6245	\$ 7.18
86	0.6334	0.3666	0.3650	905.42	0.1751	0.1915	\$ 29.32
87	0.4559	0.5441	0.4340	162.27	0.1896	0.3546	\$ 101.79
88	0.6441	0.3559	0.3484	1065.55	0.1560	0.2000	\$ 25.27
89	0.2350	0.7650	0.3568	50.91	0.1744	0.5906	\$ 95.39
90	0.5893	0.4107	0.3530	43.95	0.1694	0.2413	\$ 1156.12
91	0.5927	0.4073	0.3097	991.11	0.1806	0.2267	\$ 18.30
92	0.2344	0.7656	0.3376	1501.01	0.1574	0.6082	\$ 7.05
93	0.7545	0.2455	0.4001	698.92	0.1329	0.1125	\$ 238.36
94	0.3953	0.6047	0.3496	989.89	0.1385	0.4662	\$ 10.97
95	0.5971	0.4029	0.3132	1660.77	0.1630	0.2399	\$ 12.75
96	0.5241	0.4759	0.3121	911.70	0.1776	0.2984	\$ 14.69
97	0.8689	0.1311	0.3038	592.90	0.0833	0.0478	\$ 22329.1
98	0.4502	0.5498	0.3880	389.57	0.1794	0.3704	\$ 36.38
99	0.4501	0.5499	0.3744	264.46	0.1850	0.3649	\$ 48.82
100	0.6488	0.3512	0.3609	443.13	0.1587	0.1925	\$ 62.24