2000

A techno-economic study of liquefied natural gas transportation : a prospective to develop India's first import terminal

Neelima Vyas
World Maritime University

WORLD MARITIME UNIVERSITY
Malmö, Sweden

A TECHNO – ECONOMIC STUDY OF LIQUEFIED NATURAL GAS TRANSPORTATION.

A PROSPECTIVE TO DEVELOP INDIA'S FIRST IMPORT TERMINAL

By

NEELIMA VYAS
India

A dissertation submitted to the World Maritime University in partial fulfilment of the requirements for the award of the degree of

MASTER OF SCIENCE

in

PORT MANAGEMENT

2000

DECLARATION

I certify that all the material in this dissertation that is not my own work has been identified, and that no material is included for which a degree has previously been conferred on me.

The contents of this dissertation reflect my own personal views, and are not necessarily endorsed by the University.

…………………….. (Signature)

…………………….. (Date)

Supervised by:
Name : Dr. Shou Ma
Office : Course Professor, Port Management
World Maritime University

Assessor:
Name : Capt. Jan Horck
Office : Lecturer, Port Management
World Maritime University

Co-assessor:
Name : Professor Hiroyuki Adachi
Office : Deputy Director General
Shipping Research Institute
Ministry of Transport - Japan

Acknowledgement

I wish to extend my deep gratitude to the Canadian International Development Agency (CIDA), Canada - the sponsors for my studies at the World Maritime University.

Further, I wish to extend my profound appreciation to my supervisor Dr Shou Ma for his continuous advice, guidance and encouragement for the dissertation as well as during my tenure at the university as my Course professor. Your unflinching support, advice and direction has made this dissertation possible and a reality.

I would like to also acknowledge the guidance and encouragement from Captain Horck, during my studies at WMU. To Dr Francou and Cecilia for their assistance in not only helping in obtaining information but in the translation of several French documents. What seemed an impossible task due to the lack of information from the industry is finally completed. Your ever-willing assistance, belief and support assisted in putting my feet back on the ground each time I faltered and has enhanced in compiling this work. I am indebted to WMU especially to the professors and lecturers for imparting and sharing their knowledge and experience.

A very special word of thanks to my colleagues and friends, especially Nishanti as we formed the chain of determination and togetherness with a single mission to graduate successfully.

My parents and family have been a constant support, encouraging and guiding me all along the journey of challenge till today – A pillar of strength and inspiration, they are my source of hope for a better, brighter and secured tomorrow.

… *This project is a dedication to them.*

Above all my profound gratitude to the Almighty.

It has been an experience I will always cherish.

Thanking each one and all.

Abstract

Title: **A techno-economic study of Liquefied Natural Gas transportation. A prospective to set up India's very first import terminal.**

Degree: **MSc**

India faces challenges in the energy and environment sector presently, with a large deficit of electricity. Commercial fuel sources can be coal, oil, natural gas, hydro and nuclear power. The Primary fuel sources for electrification in the country are coal and oil however, natural gas should be considered as an alternate resource. Being a clear, environment friendly fuel as compared to the high carbon emissions from the other fuel can position gas as the choice of energy now and in the future.

As gas distribution is uneven along with the insufficient domestic supply it calls for the country to import gas. Transportation and production are the major cost elements contributing to the projects being capital intensive and complex. This is also because of the characteristic feature of the contract, which are long term (20-25 years), involving supplier, facilitator and consumer. An alternate to make LNG viable thus needs to be considered to enhance its possibility as an alternate fuel source as well as the fuel of the future.

The dissertation discusses the geographic location of suppliers, the reserve/production ratios, cost per kWh for power plants, project financing and pricing mechanism. It further addresses the developments in technology from safety prospective, as well as transportation of the gas as a frozen hydrate instead of the traditional liquefied form.

Key words: LNG, NGH, India, Economies, Pricing, and Technology.

Table of Contents

List of Tables

List of Figures

Glossary of definition and abbreviations

Absorption: A process for separating mixtures into their constituents, on the basis that some components are more readily absorbed than others. E.g. is the extraction of the heavier components from natural gas.

API gravity: American Petroleum Institute scale used to express the specific gravity of oils.

Aromatics: Hydrocarbons with a ring structure, generally with a distinct odour and good solvent properties.

Associated gas: Natural gas found in association with oil in a reservoir, either dissolved in the oil or as a cap above the oil.

Barrel (bbl): A standard measure for oil and oil products. One barrel = 159 litres.

Base load project: Projects, which provide a continuous, stable supply of gas, usually sufficient to meet normal demand.

Boil - off: A process of vaporisation of very small quantities of refrigerated liquid by heat conducted through the insulation surrounding the storage tank.

BP: Bharat Petroleum

Brent blend: A blend of North Sea crude, used as an international marker for crude oil pricing.

British thermal unit (BTU): The quantity of heat required to raise the temperature of one pound of water through one degree Fahrenheit.

Butane: A hydrocarbon consisting of 4 carbon atoms and 10 hydrogen atoms C_4H_{10}. Normally a gas, but easily liquefied for transport and storage.

Calorie: The amount of heat required to raise the temperature of 1 gm. of water through 1 ^{o} C.

Calorific value: The amount of energy released as heat when fuel is burnt.

Catalyst: A substance, which accelerates a chemical reaction without forming part of the final product and remain unchanged at the end of the reaction.

CO_2: Carbon di oxide: The basis for plant respiration. Liberated when plant matter decomposes or combusts. Also liberated when burning oil, coal or gas.

Dead weight tonnage (DWT): The weight of cargo, stores and fuel, which a vessel carries when fully, loaded.

Element: A chemical term referring to a substance that cannot be chemically broken down into simpler forms.

Environmental Impact Assessment (EIA): An assessment of the impact of an industrial installation or activity on the surrounding environment, conducted before work on that activity has commenced. The original baseline study, a key part of this process, describes the original conditions.

Flaring: The controlled and safe burning of gas which cannot be used for commercial or technical reasons.

Fuel oils: The heavy oils from the refining process, used as fuel for power stations, ships etc.

G SM^3: Giga standard cubic metre = 1 billion cubic metre of gas at 1.01325 bar and 15^{o}C.

GAIL: Gas Authorities of India Limited.

Gasification: The production of gaseous fuel from solid or liquid fuel.

Heat: It is a form of energy and is produced through the movement or agitation of molecules and atoms in a substance. The amount or quantity of heat is commonly measured in British Thermal Units (BTU). One BTU is equal to the amount of heat required to raise the temperature of 1 pound of water 1 degree Fahrenheit. To measure larger quantities of heat, a unit equals to 1000 BTUs and is called MMBTUs.

Hydrocarbon: Any compound or mixture of compounds, solids, liquid or gas containing Carbon and Hydrogen (e.g. Coal, crude oil and natural gas).

IEA: International Energy Administration: Established in 1974 to monitor the world energy situation, promote good relations between producer and consumer countries and develop strategies for energy supplies during emergency times.

IOC: Indian Oil Corporation.

KOGAS: Korea Gas Corporation.

LNG: Liquefied Natural Gas: Consists of propane, butane or a mixture of 2 which maybe wholly or partially liquefied under pressure in order to facilitate transport and storage.

Mercaptans: Strong smelling compounds of Carbon, Hydrogen and Sulphur found in gas and oil. Sometimes added to natural gas for safety reasons.

Methane: The smallest hydrocarbon molecule with 1 carbon atom and 4 hydrogen atoms CH_4. It is a chief component of Natural gas as well as coal.

MMscf/day: Million standard cubic feet/day.

Naphtha: A range of distillates lighter than kerosene.

Natural gas: A mixture of naturally occurring gases found either in isolation or associated with crude oil. The main component is methane, propane, butane, hydrogen sulphide and carbon di oxide. However, these are mostly removed at or near the well head in a gas processing plant.

NGL: Natural Gas Liquid: Hydrocarbon which can be extracted as liquids from natural gas in gas processing plants or from gas field facilities. They generally include propane and heavier fractions such as butane and ethane.

NH_3: Ammonia: A direct combination of hydrogen and nitrogen under pressure over a catalyst results in ammonia.

Nm^3: Normal cubic metre under a reference condition of 0^oC and 1.01325 bar.

NO_x: Nitrogen oxides: Created by combustion of fossil fuels.

N_2O: Nitrous oxide

NTPC: National Thermal Power Corporation

Oil equivalent: Oil and gas volumes are expressed in terms of oil equivalents. As a thumb rule 1 tonne of oil equivalent = 1 tonne of oil = 1000 cubic metre of gas.

ONGC: Oil and Natural Gas Corporation.

OPEC: Organisation of Petroleum Exporting Countries: Formed in 1960. Its member countries are Algeria, Ecuador, Gabon, Indonesia, Iran, Iraq, Kuwait, Libya, Nigeria, Qatar, Saudi Arabia, United Arab Emirates and Venezuela.

Proven reserves: The quantity of oil and gas estimated to be recoverable from known fields under existing economic and operating conditions.

Qatar gas: Qatar Liquefied Gas Company.

Ragas: Ras Laffan LNG Company.

Sm^3: Standard cubic metre under a reference condition of 15^oC and 1.01325 bar.

SO_2: Sulphur di oxide: Formed from the combustion of coal and oil.

Solvent: A liquid capable of dissolving or dispersing other substances.

Specific gravity: The ratio of the density of a substance at a particular temperature to the density of water at 4^oC.

Spot market: An international market in which oil or oil products are traded for immediate delivery at the current price.

Well head: Control equipment fitted to the top of the well consisting of outlets, valves, blowout preventers' etc.

Well: Drilling as a part of the programme to determine the size and likely yield of an oil or gas field.

Thermal properties:

Temperature: It is the degree or intensity of heat and is an indication of the kinetic energy of the molecules of the body. The temperature of substances maybe expressed in either relative or absolute units. On the Fahrenheit (F) scale, water freezes at 3^o and boils at 212^o at 14.696 psi. The freezing and boiling point on the Celsius scale are 0^o and 100^o.

Conversion is

$$T_f = \frac{9}{5}(T_c + 32) \qquad\qquad T_c = \frac{5}{9}(T_f - 32)$$

Ambient temperature: The temperature of the medium surrounding the body, for example room air temperature.

Joule: Unit of measure of quantity of heat in SI system. One calorie of heat will raise the temperature of 1 gram of water 1^oC. This is equal to 4.186 joules. 1 kilojoule equals 0.948 BTU or 0.239 cals.

Conversion table

Approximate conversion factors

Crude oil*

To convert

	Tonnes (metric)	Kilolitres	Barrels	Tonnes / year
From		**Multiply by**		
Tonnes(metric)	1	1.165	7.33	-
Kilolitres	0.858	1	6.2898	-
Barrels	0.136	0.159	1	-
Barrels/day	-	-	-	49.8

*Based on world-wide average gravity

Products

To convert

	Barrels to tonnes	Tonnes to barrels	Kilolitres to tonnes	Tonnes to Kilolitres
From		**Multiply by**		
LPG	0.086	11.6	0.542	1.844
Gasoline	0.118	8.5	0.740	1.351
Fuel Oil	0.149	6.7	0.939	1.065

LNG and Natural Gas

To convert

	Billion cubic metres NG	Billion cubic feet NG	Million tonnes LNG	Trillion British thermal units
From		**Multiply by**		
1 billion cubic metres NG	1	35.3	0.73	36
1 billion cubic feet NG	0.028	1	0.021	1.03
1 million tonnes of oil equivalent	1.111	39.2	0.805	40.4
1 million tonnes of LNG	1.38	48.7	1	52.0
1 trillion British thermal unit	0.028	0.98	0.02	1
1 million barrels oil equivalent	0.16	5.61	0.12	5.8

LNG and Natural Gas

To convert

	Million tonnes oil equivalent	Million barrels oil equivalent	Million tonnes of LNG	Trillion British thermal units
From		**Multiply by**		
1 billion cubic metres NG	0.90	6.29	36	6.29
1 billion cubic feet NG	0.016	0.18	0.73	1.03
1 million tonnes of oil equivalent	1	7.33	0.805	40.4
1 million tonnes of LNG	1.23	8.68	1	52.0
1 trillion British thermal unit	0.025	0.17	0.02	1
1 million barrels oil equivalent	0.14	1	0.12	5.8

Units:

1 metric tonne	=	2204.62 lb.				
1 kilolitre	=	6.2898 barrels.				
1 kilcalorie (kcal)	=	4.187 kJ	=	3.948 BTU.		
1 kilojoule (kJ)	=	0.239 kcal	=	0.948 BTU.		
1 British thermal unit (BTU)	=	0.252 kcal	=	1.055 kJ.		
1 kilowatt hour (kWh)	=	860 kcal	=	3600 kJ	=	3412 BTU

Calorific equivalents

I barrel oil equivalents	=	5.8 million BTU.
1 tonne oil equivalent	=	10 million kcal.
1 tonne coal equivalent	=	7 million kcal.

One tonne of oil equivalent equals approximately:

Heat units	10 million kilocalories 40 million BTU
Solid fuels	1.5 tonnes of coal
Electricity	12 megawatt – hours

1 million tonnes of oil produces about 4000 gigawatt-hours of electricity in a modern power station.

Source: BP Amoco Statistical Review of World Energy 2000.
Statoil, Shell, Marubeni Corporation

Natural Gas Composition

Component	Pipeline inlet gas %	Common gas %	High – purity LNG %
Methane	81.3 – 97.5	95.3	97.5 – 99.5
Ethane	2.0 – 7.0	4.1	Less than 1.0
Propane	0.27 – 3.0	0.43	Less than 0.1
Iso – butane	0.03 – 0.32	0.04	-
N – butane	0.01 – 0.90	0.01	-
Hexane	0.02 – 0.17	0.05	-
Water	3.5 – 20 pounds/MMcf	-	-
Nitrogen	0.26 – 10.0	0.02	Less than 2.5
Oxygen	0 – 10 ppm	-	-
Carbon di oxide	0.47 – 1.5	-	-
Sulphur	0 – 1.2 MMcf	-	-

Source: LNG express: LNG Market Statistics March 2000.

Trillion equals 1 million million	=	10^{12}
1 trillion cubic feet of natural gas	=	26 million tonnes of oil.
1 million tonne of LNG	=	0.05 trillion cubic feet (gas)
1 billion cubic metre corresponds	=	0.04 trillion cubic feet (Tcf)

Chapter 1
Introduction

The Republic of India faces great challenges in energy and environment sector as it enters the 21st century. It is the world's 7th largest energy consumer and is planning major energy infrastructure investments to keep up with the increasing demand particularly for electric power. Power outages are a common feature and to meet the electricity deficit the government has targeted a total capacity of 47,000MW for the current 5-year plan and 113,500MW by 2007. The power shortages increased during the Indian fiscal year 1998-1999 with a 5.6 % overall shortage and 11.3 % peaking shortage. The country relies on coal for 55 % of its energy requirements whilst oil accounts for about 31 % of the energy consumption. The rapidly growing population will continue to increase demands for electricity generation and will place greater pressures on the environment to absorb carbon emissions. The past few economic surveys have emphasised the need to accelerate, widen and deepen reforms of the formerly non-tradable infrastructure (ports, railways and roads) and the energy sector, to avert an impending mismatch between the economic growth and position of services. It thus becomes pertinent to analyse the fuel source for these power plants and to consider an alternate.

Natural gas is seen as an increasingly important source of energy for the power plants of the country. It is environment friendly, clean, absent of SO_2 and with reduced N_2O and CO_2. India has not imported LNG prior, nor has it any import terminals as of date.

Indian consumption of natural gas however, is presumed to rise faster than any other fuel in recent years. From 0.6 trillion cubic feet (Tcf) p.a. in 1995 natural gas is projected to reach 1.2 Tcf in 2001 and 1.9 Tcf in 2007. Increased use of natural gas in power generation will account for most of the increase, as the government is in the process of encouraging the construction of gas-fired electric power plants. LNG supports the use of combined cycle gas turbine for power generation (CCGT). These are relatively more efficient and less hazardous to the environment as compared to other power generation fuel alternatives. Given that the domestic gas supply of 0.6 Tcf is not likely to keep pace with the projected gas demand of 1.9 Tcf in 2007, India will have to import most of its gas requirements either via pipelines or LNG tankers making it one of the world's largest importers in the near future. An energy policy can be framed for long term measures to adequately maintain the required supplies of energy resources. In the case of natural gas, the policy would entail an assessment of power and security, to growing imports of natural gas in the world economy, trends in global supply, demand, concerns for environment protection and pricing mechanism.

As many of the world's gas fields are not located near potential customers, gas must be either piped long distance or liquefied and transported by specialised tanker. The option of importing LNG alongwith its uses in CCGT has expanded the potential for meeting electrification goals in developing countries especially Asia.

Thus, Chapter 2 discusses the world-wide energy scenario and demand / supply of the natural gas market which may assist when considering the supplier. The world LNG industry is currently facing pressures, which is likely to change the face of the industry. The Asian crisis intensified the impetus for structural change in the LNG markets, resulting in the emergence of new markets like India and China as well as the expansion of the existing ones.

Natural gas being an environment friendly fuel is the fuel of the future. Its only drawback is the cost of production and transport, since it must also compete with oil and other fuel sources which is brought forth in Ch 3 – LNG economies and natural gas pricing. This is due to the processing amount and the expense associated with transporting gas to the consumer. LNG requires to be converted from gaseous to liquid before shipping, transporting in special designed refrigerated, specialised ships and delivering to ports equipped with special receiving facilities. It then must be regasified and distributed to consumers, resulting in traditionally being more expensive on a cost basis as compared to alternate resources.

Technology has and will respond to challenges and has also advanced since the last 20 years. Chapter 5 addresses the subject of design and technological developments from safety prospective, which is one of the major criteria of LNG transportation. However, the present challenge is, in simple terms to reduce transportation costs without any sacrifice in the high safety standards and reliability, which the industry has established. Thus it was considered vital to analyse transportation leading to the concept of transporting LNG not in the traditional form at $-161.5^{o}C$ but as frozen hydrate. This is discussed in Chapter 4 – Natural Gas Hydrate – a new dimension.

Every LNG project is a complex chain extending from the well head to the reception terminal and finally to the gas consumer. Each link of the chain is an integrated contract covering a period of approximately 25 years of which the import terminal is only a part. Chapter 6 refers to some recommendations based on the preceding chapters so as to develop the chain (since the country has no import terminal).

LNG as an energy import option is significant in that it reduces certain countries' especially India's dependency on oil and coal imports and also helps achieve environmental goals by providing greater opportunities to utilise relatively cleaner burning natural gas.

Thus the objective of this research is an attempt to study the techno economies of natural gas with the prospective to develop an import terminal and thereby highlight the possibilities of using LNG.

To accomplish this, the author faced immense difficulties in obtaining information and data, resulting in almost abandoning the research at certain phases. It is thus a humble appeal to the industry to open its doors to research so as to assist development and growth.

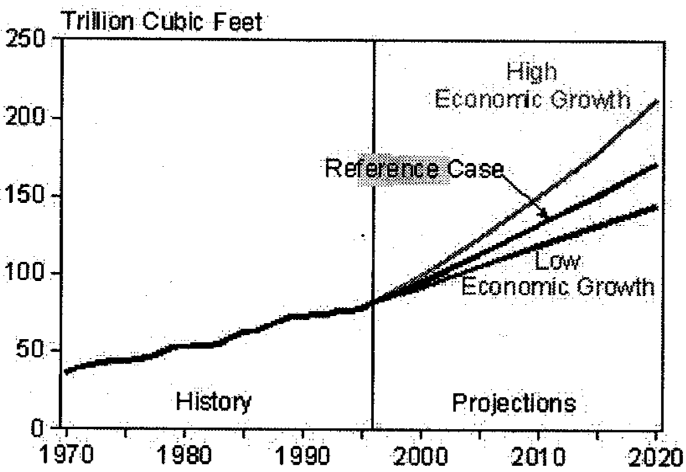
Chapter 2

Development Pattern of LNG world – wide and the Indian energy scenario

This chapter discusses the world-wide distribution of natural gas and its development pattern, along with the reserves of the major suppliers and demands of the importers. It also addresses the status of the energy requirements in India with the objective to highlight the possibility of using LNG. Today there is immense discussion in the country to consider LNG as the alternate fuel source especially for the expanding power sector to meet the energy requirements.

2.1 World wide Natural Gas scenario:

According to the International Energy Outlook (IEO 98) the total world natural gas demand is expected to reach 172 trillion cubic feet by 2020, an 85 % increase over the 1996 level of 78 trillion cubic feet.



Source: International Energy Administration (EIA), Office of Energy Annual 1996, DOE/EIA-0219Projections: EIA, World Energy Projection System 1998

Fig. 2.1 World – wide Natural Gas Projection

Further, the natural gas as per the study conducted by EIA (1998) is expected to grow rapidly as the primary energy source in the next 25 years with the consumption projected as 3.3 % per annum by 2020 as compared to 2.1 % oil and 2.2% for coal, as indicated in Table 2.1

Table 2.1 World energy consumption by energy source 1970 – 2020

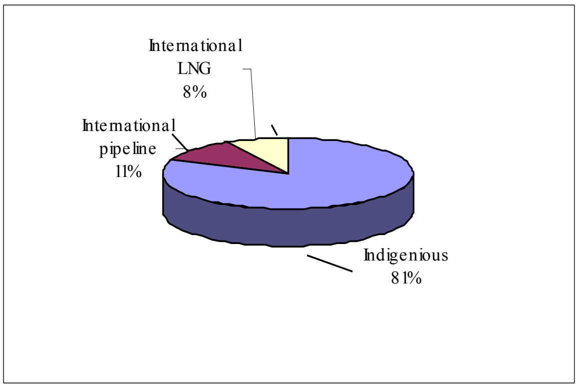
Million tonnes oil equivalent

Energy source	**1970**		**1995**		**2010**		**2020**		**Proj. annual % change**
	M Tons	%	M tons	%	M tons	%	M tons	%	
Oil	97.8	47.3	1425	39	195.5	37.6	237.3	37	2.1
Natural gas	36.1	17.5	78.1	21.4	133.3	25.6	174.2	27	3.3
Coal	59.7	28.9	91.6	25.1	123.6	23.8	156.4	24.5	2.2
Nuclear	0.9	0.4	23.3	6.4	24.9	4.8	21.3	3.5	0.4
Renewable*	12.2	5.9	30.1	8.23	42.4	8.2	50.2	8.0	2.1
Total	206.7	100	365.6	100	519.6	100	639.4	100	2.3

- solar, wind, hydro

Source: Energy department administration (EIA) World energy project system 1998.

The increase of LNG share has been found to increase rapidly from 4.4 % in 1985 to 8 % presently making it likely that there will be a rise over the next 10-15 years as is indicated in the graph by BP Statistical Review 1998 Figure 2.2. Transportation is a key aspect in LNG especially since reserves and consumer countries are remotely situated at distances. As there is a developed pipeline network in FSU, Europe and North America most of the gas in these countries is transported by pipelines. In its gaseous state gas is heavy and bulky (a high pressure gas pipeline can transmit about a fifth of the amount of energy a day as compared to oil). Thus it is cooled to –161°C into a liquid form and transported over long distances across oceans.

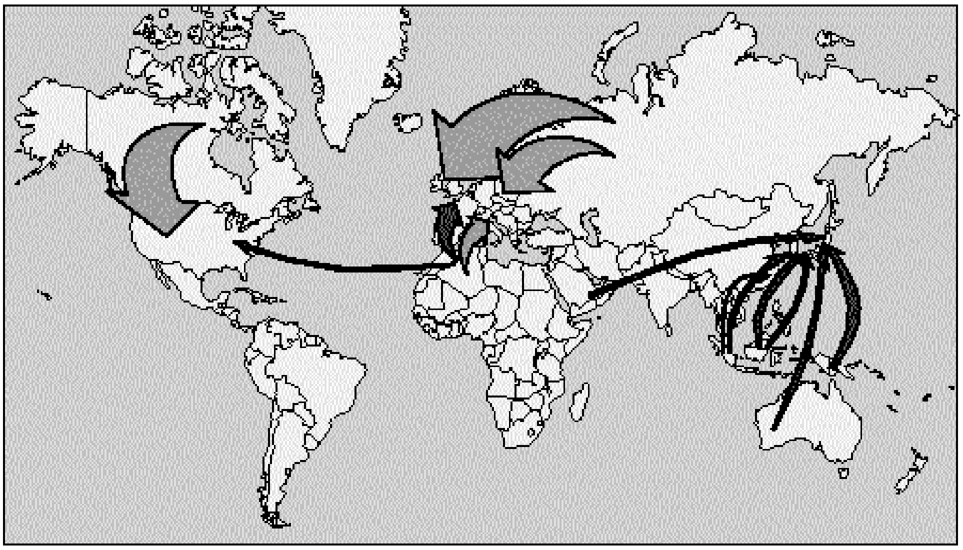


Source: BP Statistical Review 1998

Fig. 2.2 World Natural Gas Consumption

A market analysis by the Energy Administration Department (1998) also suggested that a large proportion of increased LNG use would be in Japan, South Korea, India, Thailand and perhaps China.The existing LNG plants currently account for more than 4.0 trillion cubic feet of capacity per annum. Planned extensions to the existing capacity involve addition of almost 1.4 trillion cubic feet of capacity. Additional proportional capacities ranging from 1.4 to 4.3 trillion cubic feet by 2003 are in stages of planning and negotiation. Thus it is possible that the LNG processing capacity could nearly triple in the next decade or so.

Figure 1. World Natural Gas Trade Patterns, 1995



Note: Dark arrows represent LNG transport. Light arrows represent pipeline transport.
Source: British Petroleum Company, *BP Statistical Review of World Energy 1996* (London, UK, June 1996), web site 165.121.20.76/bpstats.

Fig. 2.3 World Natural Gas Trade Pattern

Fig.2.3 also indicates that the European demand for shipped LNG is likely to be limited due to the presence of developed land pipeline network. Current projections suggest that imports are likely to rise to around 10 million tonnes in year 2000 and 20 million tonnes by 2010.

2.2 Development pattern of LNG: Demand and Supply

The lead-time of LNG projects is very, long during which the oil prices may fluctuate quite considerably. For example, the Sarawak, Malaysia project, which was completed in 1983, took about 13 years to develop. To set up projects the trade pattern is vital. For easier understanding this is divided into the Far Eastern, West Europe and United States of America:

Table 2.2 Summary of Far Eastern LNG trade to 2000

Million tonnes

	1989	1990	1995	2000
Importer				Projected
Japan	32.0	35.5	42.0	48.5
S.Korea	2.0	2.3	4.0	8.2
India	-	-	-	6.6
Taiwan	-	0.5	3.7	4.5
Other	-	-	-	0.5
Total	**34.0**	**38.3**	**49.7**	**68.3**
Exporter				Projected
Indonesia	18.2	20.5	25.6	29.5
Malaysia	6.5	6.5	9.8	12.8
Australia	0.7	2.8	5.8	8.0
Brunei	5.1	5.1	5.1	6.2
Abu Dhabi	2.3	2.3	2.3	4.5
Algeria	0.2	0.1	-	3.7
Alaska	1.0	1.0	1.1	2.1
Qatar	-	-	-	1.5
Total	**34.0**	**38.3**	**49.7**	**68.3**

Source: Ocean Shipping Consultants

Table 2.3 Summary of West Europe and USA LNG trade to 2000

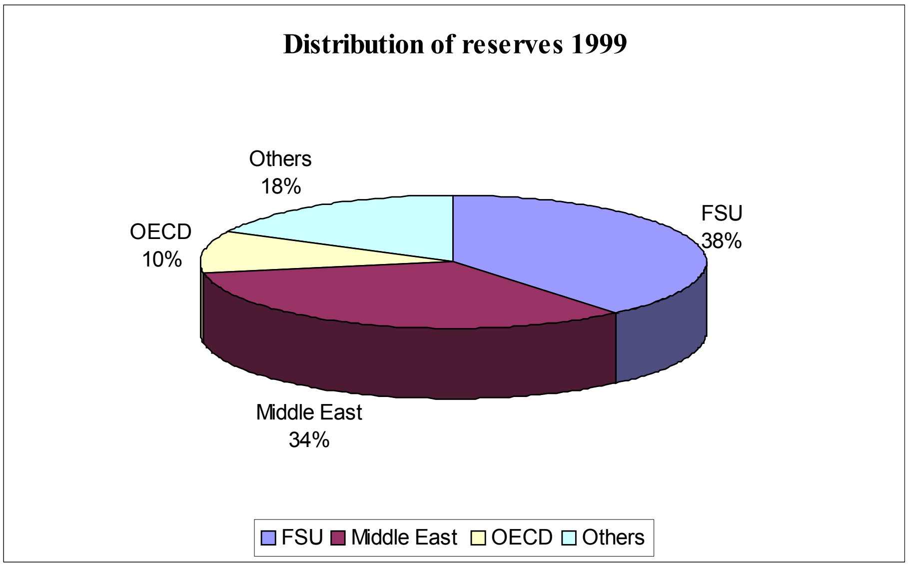
Million tonnes

	1989	1990	1995	2000
Importer				Projected
W. Europe	12.4	14.0	18.1	23.1
USA	1.0	3.2	6.8	11.3
Total	**13.4**	**17.2**	**24.9**	**34.4**
Exporter				Projected
Algeria	12.3	15.6	19.3	22.8
Nigeria	-	-	-	4.5
Venezuela	-	-	-	4.5
Libya	1.1	1.6	1.6	1.5
Total	**13.4**	**17.2**	**24.9**	**34.4**

Source Ocean Shipping Consultants

2.2.1 World proven gas reserves

Natural gas is a desirable energy source, which burns cleanly, environment friendly and little pollution. The reserves of the natural gas world wide as reported by Oil and Gas Journal (1998), was approximately 5086 trillion cubic feet, which can be sufficient for about the next 60 years current world gas production. About 73% of the gas reserves are located in Middle East and Former Soviet Union as is indicated in fig. 2.4 below.



Source: BP Statistical Review 1999

Fig. 2.4 World proven gas reserves

However, one of the obstacles is the availability of the reserves. They are located in remote and thinly populated areas of Western Siberia and the Gulf. Presently the technology to build long distance pipelines through the depth of oceans does not exist. Thus moving gas across the continents is an alternative approach.

2.2.2 LNG exporters and importers

Following tables 2.4 and 2.5 show the LNG trends handled from 1990 to 1998 indicating that there has been a steady increase.

Table 2.4 Major LNG exporters: million tonnes

Countries	90	91	92	93	94	95	96	97	98
USA	1.4	1.3	1.4	1.4	1.6	1.6	1.6	1.7	1.8
Qatar								2.9	4.74
UAE	3.2	3.5	3.4	3.4	4.3	6.9	7.3	7.6	7.3
Libya	1.3	1.6	1.8	1.6	1.5	1.5	1.2	1.1	0.88
Algeria	19.1	18.9	19.6	20.2	18.3	18.3	19.6	24.3	24.8
Australia	3.9	5.2	6.2	6.7	8.6	9.8	10.2	9.8	10.1
Brunei	7.2	7.0	7.1	7.6	7.8	8.5	8.7	8.2	7.88
Indonesia	27.6	30.0	31.6	31.9	35.1	33.2	36.0	35.7	36.28
Malaysia	8.6	9.5	9.5	10.5	11.0	12.9	17.7	20.1	19.45
Total	**72.3**	**77.0**	**80.9**	**83.3**	**88.2**	**92.7**	**102.5**	**111.8**	**113.3**

Source. Compiled from BP Statistical Review 1998 – 1999.

Table 2.5 Major LNG importers: million tonnes

Countries	90	91	92	93	94	95	96	97	98
USA	2.5	1.9	1.3	2.3	1.5	0.6	1.2	2.0	2.21
Belgium	3.9	4.1	4.6	4.3	4.0	4.2	4.0	4.5	4.2
France	9.31	9.2	9.2	9.0	7.7	8.4	7.8	9.2	10.2
Italy	0.03	0.1	0.6	0.3	0.2	0.10		1.9	2.07
Spain	4.5	5.2	5.7	5.9	6.4	7.1	6.9	6.7	6.3
Japan	47.94	50.7	52.7	53.1	56.8	57.9	63.8	64.3	65.96
S. Korea	3.1	3.7	4.6	6.1	7.9	9.43	12.98	15.7	14.2
Taiwan	1.0	2.1	2.2	2.3	3.0	3.5	3.4	4.1	4.98
Total	**72.3**	**77.0**	**80.9**	**83.3**	**88.2**	**92.7**	**102.5**	**111.8**	**113.3**

Source: Compiled from BP Statistical Review 1998 – 1999.

From the above it is also seen that USA is an exporter and an importer of LNG but the imports are larger than the exports as indicated in table 2.7 below:

Table 2.6 USA Natural gas demand and supply: 1989 – 2000

billion cubic metre

	1989	1990	1995	2000
Consumption	552	553	572	592
Production	496	493	497	578
Imports	40	47	71	76
Exports	2	2	2	2
Stocks	(18)	(15)	(6)	-

Source: Ocean Shipping Consultants

To explain the above situation of exporting and importing LNG in the writer's view it is necessary to analyse it on a terminal to terminal basis. Briefly, this is as follows: the imports are mainly at Everett, Charles Lake, and Cove Point. e.g.: Distrigas of Boston imports from Algeria and has two contracts:

i. 1.6 million metric tonnes per annum for a period of 15 years 1990 - 2005.

ii. 0.6 to 1.0 million metric tonnes per annum for 3-5 years as a deal for part payment of three Boeing aircraft sold to Air Algeria. Further Distrigas is proposing to receive 0.5 million metric tonnes from LNG Nigeria.

Exports are mainly from Alaska; Kenai exporters export 1.0 million metric tonnes per annum to Japan on a long term contract of 20 years till 2005. Further an ambitious plan to export 6.0 million metric tonnes per annum from North Slope is being considered. The long lead time characteristic of large-scale projects means a commencement only after 2000.

The following provides an overview on the status of the major LNG importing countries based on the International Energy Outlook (1998), US EIA report October 1998:

Japan:

The Japanese economy recently has grown slowly with real GDP increasing 1.5 % on an average from 1991 to 1995. The real GDP increased 4.1 % in 1996 but decreased by 0.8 % in 1997 and continued to be negative in 1998/ 1999. Although the LNG imports increased by 3 % in 1998, the growth rate was lower as compared to 1975 - 1995 (12%) and has resulted in having a strong impact on LNG prices.

Japan imports the largest amount of LNG 47 million metric tonnes (2.3 trillion cubic feet) the major bulk from Indonesia and Malaysia (57%) although supplies are also imported from Australia, Brunei, UAE and USA (56 billion cubic feet). By signing the long-term agreement with Qatar in 1997, Japan plans to further import 0.35 million metric tonnes. With the signing of this contract Qatar enters the LNG industry for the first time. Several analysts see this agreement by Qatargas and Chuba Electric power of Japan as a major milestone. Qatargas is contracted to supply Chuba approximately 6 million metric tonnes of LNG gas per year for a period of 25 years. This is the first of the 3 projects under way to export upto 12 million metric tonnes of gas per year from Qatar North field by 2000. The 2nd project, Ras Laffans LNG is under construction and is scheduled to be onstream by end 2000.

South Korea:

South Korea follows Japan in LNG consumption. Between 1990 - 1996 the real GDP growth rate averaged 7.4 %. In 1997 it was the 2nd largest customer world-wide importing 11.3 million metric tonnes of LNG. Between 1993 – 1997 the LNG imports increased by 140 % and accounted for 14 % of global imports.

South Korea began importing LNG 10 years ago in order to provide a clean alternative fuel in the electric sector. The Korean Gas Corporation (KOGAS) is currently increasing gas supplies to residential, commercial and industrial users. The residential sector of LNG is expected to grow from 34 % to 40 % between 1996 and 2010. Kogas has estimated to triple its LNG imports between 1997 – 2010.

European demand:

In Spain LNG accounts for 81% of the country’s total natural gas consumption in 1995. Demand in Western Europe is expected to grow by as much as 155 million metric tonnes per annum by 2010. Some 50 million metric tonnes to be met by supplies from Middle East. The Atlantic LNG project, which just commenced its operations in September1999, is expected to market a larger part of its operation to Spain and to the Northeast United States.

2.2.3 Impact of Asian economic crisis on LNG importers and exporters:

The LNG business is considered as an industry presently at crossroads. Traditionally dominated by Asian importers and exporters the Asian crisis is expected to create an oversupply of LNG in the world market due to decreasing energy demand in South East Asia and East Asia. The major supplies in South East Asia have been affected by the economic crisis, as they have to deal with the decrease in prices as well as the challenges facing their own economies.

The LNG exporters in the Middle East are not directly affected by the crisis placing them in a stronger position to negotiate as compared to the other Asian exporters. This situation could alter the traditional LNG suppliers market.

Consequently, the impact of the Asian economic crisis that began in 1997 has had negative repercussion for several major countries in the LNG market. According to the Petroleum Economist – The problems Multiply in Asia September 22,1998, it is understood that the Asian LNG customers are cutting their imports by 40%. Several project delays and cancellations of contracts have occurred. Looking at it from the short-term viz. 5-8 years, this is likely to cause an oversupply of LNG in the market thereby decreasing the LNG prices. On the long-term 10-20 years, it could make LNG more competitive as compared to other fuels. As a result several producers particularly from Middle East are looking for **new markets** namely in China and India.

The decreased LNG price and a weak demand adversely impacted exporters of LNG in Asia. Indonesia and Malaysia have been more affected as compared to producers from other regions, as they are suffering from their own economic woes as well as decrease in customer demand in Asia.

In 1997, Indonesia was exporting 26 million metric tonnes but the economic crisis as well as the currency crisis' (devalue of currency) impact affected the LNG business. For e.g. Osaka Gas Company (Japan) reduced its imports from Indonesia (40 % of its supply) in order to reduce its dependency given the economic and political turmoil. The 6.0 million metric tonnes per annum Tangguh LNG proposal, has been delayed to 2004.

Malaysia accounted for 19 % of the total world LNG exports in 1997. Although having several years of strong economic growth, it is presently feeling the effects of the South East Asian crisis with an average percentage change of – 6.4 % GDP in 1998 to – 1.5 % in 1999 *(Source: The World Bank and IMF estimates Feb. 1999)*. Japan nevertheless has increased its imports from Malaysia to meet its reduction of imports from Indonesia.

Middle East LNG suppliers:

The Asian economic crisis increased competition among the exporting countries and resulted in Middle East rising as a new source of LNG supply with several projects commissioned and some coming on line. This is because Middle East supply is competing in prices with the traditional suppliers of Asia Pacific such as Malaysia, Indonesia, Brunei and Australia.

Qatar:

The main companies are Qatar Liquefied Gas Company (Qatar Gas) and Ras Laffan LNG Company (Ras Gas). Ras Gas is exporting 0.6 million metric tonnes per annum from 1999 to Korea Gas Corporation (KOGAS). This is expected to increase to 4.8 million metric tonnes per annum by 2003. Qatar Gas supplies mainly to Spain, Turkey and Japan.

Oman:

Oman LNG is proposing to supply 4.1 million metric tonnes per annum to KOGAS and 0.7 million metric tonnes to Osaka Gas Company. The project presently under construction is a 2-train plant near Sur at a cost of $2 billion. It also plans to sell 1.2 million metric tonnes per annum to India – Dabhol power plant project for a period of 25 years. This supply agreement is mainly due to the outcome of Oman seeking new markets as a result of the Asian economic crisis.

2.3 New LNG markets and projects:

2.3.1 China:

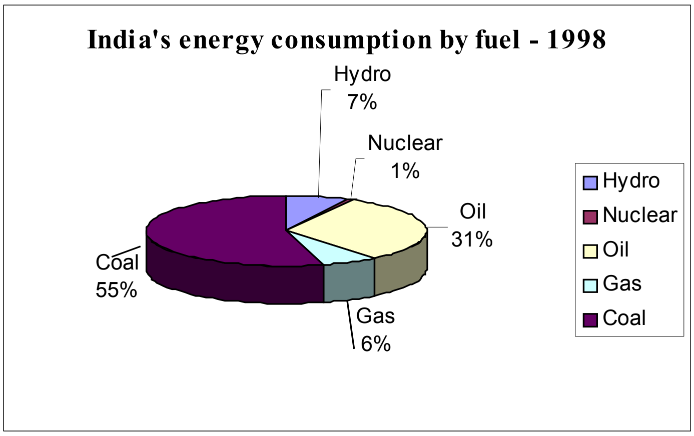
Although natural gas has not been a major fuel, given the domestic reserves and the environmental benefits of using gas, the country is encouraging the expansion of its gas infrastructure. As per the EIA report (1998) and BP Statistical Review (1999), presently gas accounts for only 2 % of the total energy but is estimated to triple in 2010 to a projected value of 1.1trillion cubic feet. This will result in an increase in domestic production as well as imports. China also proposes to build a gas distribution grid with a capacity of 5.3 trillion cubic feet.

Guangdong has started to build six 320 MW LNG power plants as well as converting the existing 1.8 giga watt oil plant to LNG. Further Shanghai is securing foreign funds and technology to build a $300 million LNG storage unit. The government considers LNG as a cleaner energy source as compared to coal. Coal currently meets 72 % of Shanghai's fuel needs and it is projected that consumption will reach 60 million tonnes by 2010. Shanghai would thus import approximately 3 million metric tonnes of LNG to meet requirements if they diversify fuel.

The effect of the Asian economic crisis is less severe in China as compared to the other Asian countries. The real GDP in 1998 was 7.8 % as compared to 8.8 % in 1997 according to the US EIA (1999). While growth in consumer demand slowed a surge in the infrastructure, the government public works helped to keep the GDP from declining further. Net foreign direct investments fell to $36.7 billion in 1998 as against $41.7 billion in 1997 due to the Asian crisis *(Source: US EIA June 1999).*

2.3.2 Energy in India's economy:

The 1990s have been a time of rapid economic change in India. By the mid – 1990s, India's real GDP growth rate reached a rate of 7.4 % (1996- 1997). However, in 1998 – 1999 the real GDP was 4.6 % as a result of sanctions but is projected at 6.0 % for 1999-2000. For the next few years real GDP is projected at around 7.0%. Between April 1998 – Feb.1999, there was a modest inflow of $442 million as compared to $1.5 billion in '97 -'98. *(Source: US EIA 1999)* This is mainly in response to the Asian economic crisis, India's nuclear tests and policy changes to encourage foreign investments. Earlier there was restriction on foreign ownership as minority stake but it has now been relaxed. This is done by the government eliminating the industrial licensing, reducing tariffs and trade restrictions. In 1994 the central government also announced that it would offer counter guarantees especially in power purchasing agreements. Later it allowed foreign investors part equity / ownership in power projects and transmission lines. This is encouraging as LNG projects are capital intensive and as discussed later led to the formation of several joint ventures with foreign partners.



Source: Compiled fromUS EIA (1999), Indian Economic Survey 1998

Fig. 2.5 India's energy consumption by fuel – 1998

According to the US Energy Administration Report 1999, coal accounts for about 55 % of India's total energy consumption. The indigenous production fell by 2.8 % i.e. to 33 million metric tonnes in '98 –'99, compared to a growth of 2.9 % in the earlier years. This is attributed to the ageing oil field, inadequate power supply and water cuts. Oil accounts for 31.5 % of the energy consumption. India's 9th Five - year plan states that the country will run out of oil reserves by 2012 and emphasises the need for new discoveries or finding alternate sources to prevent this outcome. A government panel studying the sector has recommended that the state owned oil companies be privatised by 2005. A deregulation of the industry and a relaxation of price controls are expected to take place by 2002. Exxon Mobil, Royal Dutch/ Shell and Total Fina have as a consequence reported interests in acquiring stakes in the privatised firms.

India's energy consumption per unit of output is still rising. Between 1980 – 2010 India's energy / GDP ratio is expected to fluctuate only slightly. India's per capita energy consumption is low, but rising. However as per figure 2.6 the per capita energy consumption is projected to grow from 6.2 million British thermal Unit (BTU) in 1980 to 18.2 million BTU in 2010 – a rise of almost 300 %. *(Source Energy Information Administration 1998).*

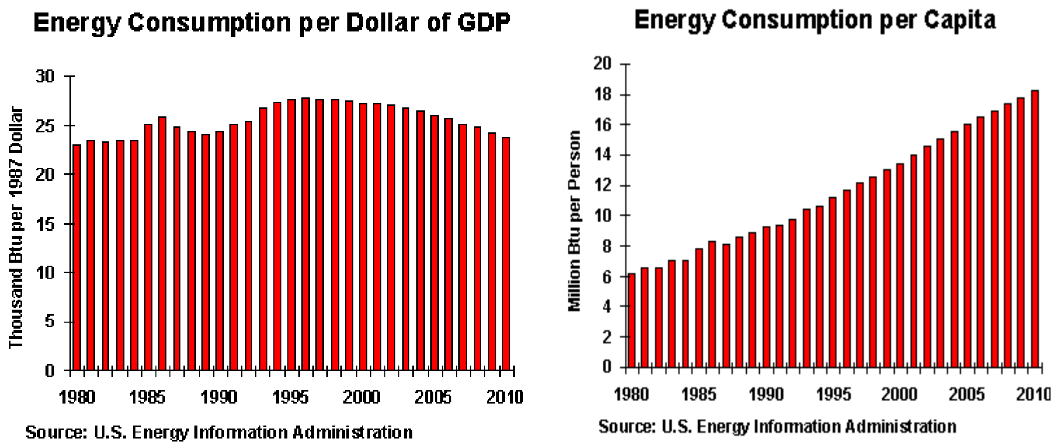


Fig. 2.6 Energy Consumption per $GDP / per capita

2.4 LNG in the Indian scenario

LNG – "Clean" fuel is being projected as the fuel of this century in India. It is considered environment friendly – cleaner than coal and cheaper than naphtha (a crude oil product) from environment viewpoint. LNG is presently being considered as a serious option for power consumption and fertiliser units especially as the gas maybe allowed to be imported under the Open general licence (i.e. the Export-Import EXIM trade policy which marks a shift towards a more liberal trade regime. The policy shifted 849 items from the restricted import list to the freely importable category – open general license. This indicated not only the government's commitment to the adherence to the WTO but as well as attempting to expedite it).

The Indian government is further encouraging gas based electric power plants in coastal areas where they can be supplied with LNG by sea. Natural gas is projected as 1.2 trillion cubic feet in 2001 and 2.0 trillion cubic feet in 2005. The domestic gas supply of 0.6 trillion cubic feet is not sufficient and will thus require imports either via pipeline or LNG tankers. The country nevertheless, requires adequate infrastructure to support use of natural gas, building LNG import terminals and pipelines. Infrastructure development is needed especially in the energy, telecommunication and transportation sectors, which has been hindered by the lack of a clear policy framework for private sector participation. Private financing of infrastructure needs to be raised from domestic sources because the revenue streams of most infrastructure projects will not support exchange risk.

'LNG is the password in the boardroom and corridors of India's power, petroleum and fertiliser sector where it will primarily find application.'

2.5 Status of the probable projects and the global players

- A LNG project is being considered by Petronet, a joint venture between Oil and Natural Gas Corporation (ONGC), Indian Oil Corporation (IOC), Gas Authority India Limited (GAIL), Bharat Petroleum (BP) and National Thermal Petroleum Corporation (NTPC). Each of the state firms would own 10 % stake, with the remaining 50% offered to financial institutions and private shareholders. Petronet plans 2 import terminals, one at Cochin and the other at Dahej. As stated by the Chairman and Managing Director of the company Mr Suresh Mathur in Fairplay - October 7^{th} 1999 "With the increase in the demand of electricity by 8-9 % per annum, this project would import 7.5million metric tonnes per annum from Ras Gas – Qatar and that 4 to 5 terminals on the west and east coast will be required to meet the demand." He estimated a power capacity of 10,000 MW by 2005 and further 20,000MW by 2015. Through its 25-year contract the project proposes to import 5 million metric tonnes at the Dahej regasification terminal from 2003 and 2.5 million metric tonnes per annum from the Cochin terminal by 2005.
- A consortium headed by British Gas and including NTPC is planning an import terminal at Pipavav-Gujarat, which will initially handle 2.5 million metric tonnes per annum, LNG imports from Yemen. Here a number of foreign companies are bidding to set up the 2500MW power plant. As stated by Alan Ross Guy, director LNG of British Gas in Fairplay 7^{th} October 1999 – "With the thriving industrial sector, existing and future uncovered gas demand that is geographically

concentrated along with the positive attitude of the government and the industry, Gujarat is the most viable market."

- Enron (USA) is proposing to build an import terminal to supply the 2500 MW electric power generation plant at Dabhol with LNG to be supplied by Oman and Abu Dhabi by 2001.
- Competitions from another joint venture between India's major industrial house Tata and a subsidiary of France's energy giant Total. The project for Trombay (Mumbai) is being planned for 3.0 million metric tonnes per annum.

LNG is thus well and truly set to storm India in the opening years of this century. Indian and foreign companies are hoping that the government will come out with a clear policy – one that also embraces transport.

For proposed LNG terminals refer to India Appendix 1.

Table 2.7 India's status with LNG projects:

Project	Promoter (Terminal)	Location	LNG quantity (M tonnes pa)	Importing from	Commencement
Dabhol power 2450MW	Dabhol power[1]	Dabhol	2.1	Oman, Abu Dhabi	2001
Industrial distribution	Met Gas (Enron subsidiary)	Dabhol	2.6	Malaysia	2002
Setting up terminal	Petronet LNG	Dahej	5	Qatar	2003
Setting up terminal	Petronet LNG	Cochin	2	Qatar	After 2003
Setting up terminal	Tata India[2]	Trombay	3	Middle East	2002
Setting up terminal	Gujarat Pipavav[3]	Pipavav	2.5	Yemen	2003

Dabhol power[1] : Enron international, Bechtel, GE capital, MSEB
Tata India[2] : Tata electric and Power India (subsidiary of Total, France)
Gujarat Pipavav LNG[3]: British Gas International
Source: Fairplay October 7, 1999.

2.6 Summary: The world LNG industry facing pressures could change the industry. The Asian economic crisis intensified the impetus for structural changes in LNG market, as well as unlocking new markets and the expansion of the existing ones. Exporting countries with strong economy puts them in a stronger position to compete. This could result in the emergence of new LNG players in the coming years.

One of the emerging players considering the use of LNG is India with its major consumption in the power sector. The projected demand of 2.0 trillion cubic feet by 2005 necessitates the development of adequate infrastructure import terminals and distribution pipelines. Presently, the prospects, policy and investments are widely discussed nationally with a possibility of joint ventures with Enron, British Gas, Exxon, Petronet etc.

Chapter 3

LNG economies to set up an import terminal and a pricing mechanism

The key contributors to what has become a strong growth industry today are the fast developing economies of newly industrialised countries such as China, Korea and India, with their insatiable appetite for power generation and efficient energy production. Cost elements and pricing of LNG per unit are critical factors when considering a LNG project. This chapter will thus try to discus some of the issues related to the cost elements, financing and prices as compared to other fuels.

3.1 Elements to set up a LNG project:

To set up a LNG project the following elements are necessary:

- A substantial low cost source of natural gas that has sufficient proven reserves for the liquefaction capacity for 20-25 years is necessary for the project. These reserves must be 25-35 times larger than the plant capacity per annum as assumed delivery of gases. e.g. 500 million cubic feet per day project would require proven reserves of 5.9 to 7.7 trillion cubic feet.
- Liquefaction facility :

  This includes stripping natural gas liquids from natural gas, processing and export of liquefied gas. It further includes insulated pressurised storage tanks with sufficient capacity to load the tankers expected to call the terminal and LNG loading facilities with sheltered, deep water access to the ocean, associated infrastructure including roads, electric power, water.
- LNG tankers :

  Dedicated tankers are required. These are more complex and expensive as they need to be double hull and with special lining. An approximate cost of 135, 000 cubic meter (3 billion cubic feet) tanker is $ 220 million (although prices in Japan and Korea being negotiated are $170 million $ 160 million respectively. *(Source -Fairplay February 1999).* The transportation costs are directly proportional to the distance.

- Regasification plant :

  Handling of LNG requires special import terminals and unloading facilities, storage tanks regasification facilities and pipeline connections.

3.2 Project finance:

LNG projects are very capital intensive and require high financial capacity and project management skills. Due to the complexity and high capital investments a LNG project is likely to be undertaken only if some assurance on return on investments is obtained. The developers seek not only long term contracts but also a price, which covers capital cost and includes " take or pay " and floor price arrangement. This is to ensure that the debt can be serviced even in lower than anticipated energy environment. Often the consumers are encouraged to take a stake in the project thereby building a community of interest between the seller and buyer. It is a complex chain involving co operation of the host government (where the gas resources are located), the private or state company, government consuming country, and other consumers viz. electric utilities, gas companies etc. Besides it requires involvement of specialised organisations – shipyards, financiers, tanker operators, construction companies, process technology licensors etc. Generally long term agreements (25-30 years) are entered into involving distribution of the cost, profit and sharing of risks.

3.3 Development of an import terminal on the West Coast of India:

The setting up of an import terminal on the West Coast is based primarily on the development of the 2500 MW power plant as its major consumer. For the gas grid a feasibility study based on Oman/Yemen gas as the fuel source was undertaken. It is understood that pipeline transportation in terms of pricing, is more competitive as compared to LNG by shipment. However, in the author's view this Oman - India pipeline project has to overcome several obstacles:

- The pipeline route is very deep, extending to more than 5 km at places.

- A system of inspection and maintenance needs to be developed.
- Most of the gas reserves of Oman are presently committed. The Oman - India pipeline project is based on anticipated future discoveries.

Several Indian companies when discussing with international funding agency gave a feedback, that it appears a difficult task to raise the finances especially with the play-safe attitude of financing companies.

3.3.1 Gas demand for the project: The LNG being imported is required for power plants (domestic as well as the new proposed 2500MW plant declared by the state government), fertiliser unit and industrial purposes. The requirement as indicated whilst discussing with the consumers as well as combining with the studies conducted by Indian Market Bureau Research is 3.0 bcm / year in year 2003 with an increase to approximate to 8.0 bcm / year by the year 2015. A break up of this as per consumer is as enclosed in table 3.1

Table 3.1 Proposed Gas Demand for a new project

(Bcm/y)

Particulars	2003	2005	2010	2015
Power(domestic)	0.783	1.194	1.860	2.915
Fertiliser	0.580	1.179	1.189	1.211
Industry	0.041	0.055	0.101	0.191
Total	1.404	2.428	3.150	4.317
2500MW	1.500	2.750	3.050	3.500
TOTAL	2.904	5.178	6.200	7.817

Source: Indian Market Research Bureau Report 1999

3.3.2 Project Capacity:

Table 3.2

(Bcm/y)

Particulars	2003	2005	2010	2015
Terminal capacity (w/o 2500MW plant)		2.5	3.0	4.5
Terminal capacity (with 2500MW)	3.0	5.0	6.0	8.0

Project capacity as per calculations						
Quantity calculations for LNG :						
Assumtion power plant			2500 MW			
		1BTU	=	252 cals		
		1kWh	=	3412 BTU	= 860 Kcals	
		Thermal energy conversion @ 50 %				
	Therefore 1 kWh power will require 1720 Kcals					
		1 ton of LNG produces		1400 cu. M of gas BTU		
		1 cubic foot of gas		1000 BTU		
	Therefore 1 ton of LNG		=	1400 x 1000 x 35.315 x 252		
			=	12459132000	Kcals.	
	However, 1720 Kcal		=	1kWh		
	Therefore 1.245 ^{10} K cals		=	7243681.395	kWh	
			=	**7.244**	**MW**	
	Therefore for 2500 MW, requirement for LNG is :					
			2500/7.244	345.128	tons /hr.	
	With a peak factor of 70 %					
Annual requirement =		tons / hr x no. of day per annum x hrs /day x peak factor				
			=	345.128 x 365 x 24 x 0.7		
			=	2116327.20	tons per annum	
				2.17	MMtpa.	

Thus from the above working it can also be concluded that a 2.5 MMtpa capacity can be justifiable for a LNG import terminal.

3.4 Potential LNG suppliers:

It is essential that the LNG suppliers are not only identified but a contract is entered into for a term period of 20-25 years due to the high capital costs involved. The potential LNG suppliers considered are based on the following factors:

- available gas reserves
- reserve to production ratios
- available production facilities
- possibilities of expansion
- economic aspects
- political aspects
- shipping distances and costs

- Based on these factors the supply that can be considered for West Coast is as shown in Table 3.3 reserve and production details:

Table 3.3 Natural Gas Reserve and Production

Country	Reserves Trillion cubic metre	Production Billion cubic metre / year	R/P Ratio
Abu Dhabi	5.3	14.78	358
Iran	21.0	31.00	677
Qatar	7.1	12.89	550
Oman	0.6	12.15	49
Algeria	3.6	50.33	72
Australia	0.6	28.11	21
Malaysia	1.9	23.4	81

Source: BP Amoco Statistical review of World Energy 1999

From table 3.3 based on the reserve / production ratios as well as considering the distance to the West coast the recommended suppliers in view are Abu Dhabi, Qatar, Oman, Iran and Malaysia. Although Algeria was considered during the initial phases of one of the projects it may not be viable since presently the production is entirely committed, the latest being the supply to the Atlantic-Tobago project which commenced its operation in September 1999. Also, due to its geographical location Algeria prefers exporting by pipeline to its neighbouring countries and Europe. Transportation to India would involve transiting through the Suez Canal, which could be a security problem and thus a constraint.

Generally a project needs sufficient gas to supply it for about 20 years with a reserve to production ratio of 10-15 times, to ensure that the full contract amount can be produced at the end of the contract period. Arithmetically, if annual deliverability is 500 million cubic feet per day (0.1825 trillion cubic feet per annum) then the amount needed is 25 to 35 x 0.1825 = 4.6 to 6.4 trillion cubic feet. If one accounts for "shrinkage" from extraction of natural gas liquids and non hydrocarbon gases, as well as liquefaction plant and tanker fuel use, reserves need to be about 20 % larger

i.e. 4.5 to 6.4 x 1.2 = 5.4 to 7.6 trillion cubic feet.

3.5 Costing and financial analysis of import terminal :

3.5.1 Requirements for an LNG terminal

Thus to develop a LNG import terminal of 3.0 bcm / year capacity the land required is approximately 50 hectares and for the power station about 100 hectares.

(1 hectare = 10,000 sq. mtr. = 2.471 acres)

Base case for costing and financial analysis:

Gas demand scenario	Domestic +2500MW power plant
PLF of 2500MW power plant (Peak load factor)	7000 hours.
LNG source	Gulf
Terminal capacity	3.0 bcm / y (2003) to 6.0 bcm / y (2010)
Economic life of ships	20 years
Economic life of terminal	20 years
Economic life of power station	25 years

3.5.2 Costs for setting up the import terminal on the West Coast:

Table 3.4 Project cost

Particulars	Million USD
Land *(Area of land 50 hectares (Rs 172 per sq. mtr. Rs to USD @ 43/)*	2.5
Site development *(@ Rs 75 per sq. mtr)*	1.5
Civil works	14.25
Marine works	51.02
Plant and machinery	259.45
Taxes and duties	22.10
Escalation	3.10
Interest during construction *(Interest @ 16%)*	24.00
Preliminary expenses	3.00
Margin money	5.00
Total	**385.92**
Debt to equity ratio	2:1
DSCR	1.73
IRR	21.22 % (pre tax) 13.56 % (post tax)

3.5.3 Marine transport:

For the transportation of LNG the vessels generally operating are 80,000, 120,000 and 135,000 m^3. Considering transportation ex Gulf or ex Malaysia (10/13.5 days voyage cycle time) the number of tankers required initially would be 2 or 3 (120 000m^3) with a shipping cost of approximately $1.05/mmBTU and regasification 0.66/mmBTU *(Source: Logicon Engineers Limited)*. Presently in India, as a government policy the bidders should have a stake in atleast 1 LNG carrier of not less than 125,000 m3, with some experience of operating and managing such a vessel. In addition, tenders' vessel should have transported atleast 0.65 million tonnes of LNG under time charter arrangement over the last few years.

The Petroleum Ministry of India proposes that the selected foreign bidders must float companies with domestic ship owners who would take an equity stake of minimum 20 %. Currently the charter hire for the tankers is $69,000 to $75,000 per day as against $98,600 per day (consortium of Mitsui, Enron, and Shipping Corporation of India). This may lead to spot trading as against the long term traditional shipping. However in this form of trading there are a lot of fluctuations with spot rates of $60,000 per day to sometimes as low as $30, 000. According to Market forecast-LNG Carrier Outlook: Poten & Partners, Inc. competition has lowered the cost to develop new supply as well as the price of new ships. These factors are said to make the supply competitive in the consumer market. The general procedure is LNG ships are ordered for construction subsequent to the contract depending on the specific trade and the term period. Thus charter hire according to them is determined in large part from shipyard price for new ships. Owner supervision costs, financing costs and owner's return on equity, when combined with the new building price, results in a capital section 70-75 % of total hire. However, today S. Korea shipbuilding is strong, successful and with competitive prices.

3.5.4 Project implementation: The project implementation could use either of the two approaches - the separate design and construction contract or turnkey contract. The total project period estimated is approximately 3 years i.e.

- Obtaining approvals, finalising LNG purchase and sales contract, financing scheme about 8-12 months
- Construction period about 2-2 ½ years

3.6 Breakdown costs for power plants on the West Coast utilising different fuel sources:

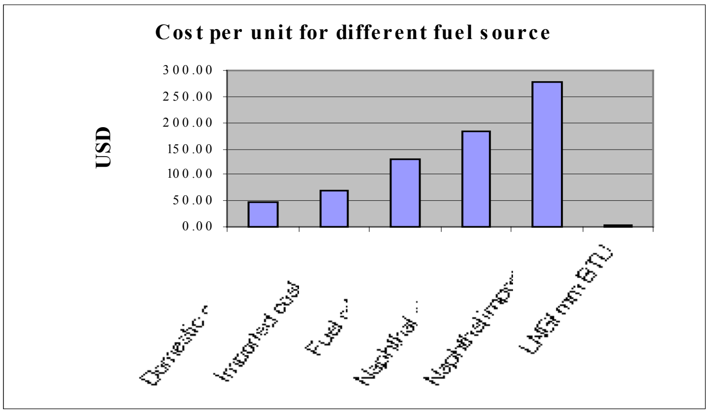
As the major user will be the power plants a study of different fuel in terms of costs is necessary to see whether LNG can be the preferred choice. From appendix 2, a summary of the cost for different fuels to the power plants is as shown in table 3.5. For cost comparison it was necessary to obtain a uniform unit and hence a conversion of fuel to per kilowatt-hour was calculated.

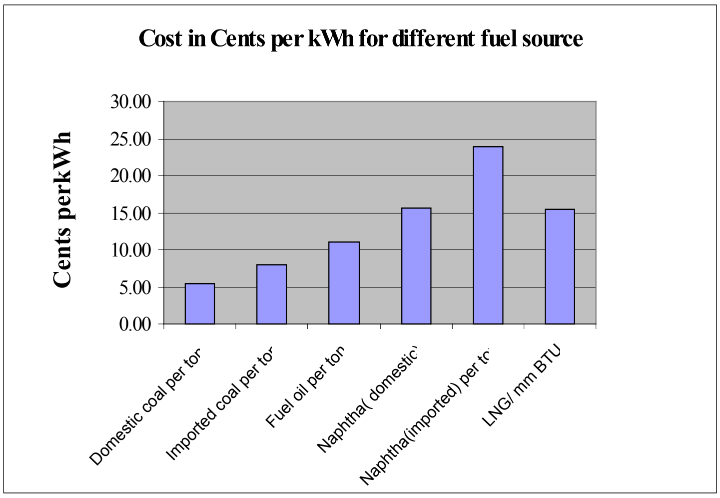
Table 3.5 Cost per unit kWh for different fuel source

Particulars	USD per unit	Cost in cents Per kWh
Domestic coal	46.13 / MT	5.36
Imported coal	68.00 / MT	7.91
Fuel oil	128.00 / MT	11.05
Naphtha(domestic)	181.00 / MT	15.64
Naphtha (imported)	278.00 / MT	23.91
LNG	4.54 / mm BTU	15.50

The per unit kWh costs in table 3.5 (detailed calculation refer appendix 4) are the landed costs at the power station inclusive of taxes, port handling, customs duty and transportation. From the above table 3.5 in the author's view although coal shows lower costs it produces high carbon emissions. The environmental effects due to the relatively high use of coal in the energy mix are exacerbated by the low energy efficiency of coal based electricity generating plants. Inefficient plants may be considered one of the main contributing factors to a steady increasing energy consumption per unit of output i.e. energy intensity.

From the calculations and Fig 3.1 the cost of LNG per kilowatt-hour is much higher as compared to the other fuels. However, this is only in the short term. Although the cost is higher consumers maybe willing to pay a premium for LNG if they believe it is important to reduce emissions of pollutants, particularly sulphur di oxide and





Source: Complied from BP Statistical Review and Calculations per kWh

Fig. 3.1 Cost Comparison of different fuel source

Carbon. Natural gas emits less carbon than either coal or oil. Besides the environmental aspects the regulatory framework, policy and fiscal structure would also assist in considering LNG as the alternate source. The decision of the government to allow the Independent Power producers to consider LNG instead of

Naphtha is already a step forward. From the costs for investments in different fuel source power plants, as well as looking at the benefits of LNG as a cleaner fuel it could be justifiable to consider LNG.

Table 3.6 Investment costs for power plants with different fuel source:

Power generation **Particulars**	Investment costs **Cost Million USD / kW**
Coal fired	1,550
Oil fired	1,300
Combined cycle gas turbine	1,000
Combined cycle(imported naphtha)	1,200
Combined cycle (indigenous naphtha)	1,100

Source: State Electricity Board, Logicon Engineers Limited

To summarise despite the high costs of LNG per kWh in the long run natural gas has 2 major advantages. Firstly is the environment being a cleaner, non polluting fuel it is an incentive for using gas in the residential, commercial, industrial and power sectors. The Energy Information Administration a department of the US energy sector has stated that natural gas is expected to be the fastest growing fossil fuel in the world between now and 2010. It could be the fastest growing overall energy source among the developing countries in this period.

Secondly the advancement of the improved technology in the gas turbine design can give gas a competitive advantage in power generation. This is observed especially in the combined cycle plants where gas turbines along with conventional steam cycle achieved thermal efficiencies close to 50 %, whereas even the most efficient coal and oil fired plants are able to achieve maximum thermal efficiencies of 40 %. Gas power stations are also cheaper, faster to build and problems with disposal of solid wastes are not there.

3.7 Elements affecting the project cost:

As already mentioned LNG projects are capital intensive and the project is likely to proceed on the developers receiving some assurance that there is an acceptable return on their high investments. A successful LNG project should try and establish a price that is low enough to motivate customers to use large volumes of natural gas, competitive to other fuels, while still high enough to persuade developers and borrowers to actually set up the project.

For e.g. for a project of 2.85 million tons per annum the costs involved are approximately $ 1.6 billion comprising

Table 3.6 Project cost US $ million

Liquefaction plant	850
Regasification plant	400
LNG carriers	340

Source: Assessment of cost and benefit of flexible and alternative fuel in the US transportation

From the above it can be said that liquefaction is one of the major factors affecting the project cost. The elements affecting the project can broadly be divided into

i. The production of natural gas.

ii. Liquefaction

iii. Voyage distances

The production of natural gas: As the contract entered into is long term the extraction and production of natural gas by the suppliers and the cost is important. From a study conducted by the US EIA department (1997-1998) it was recommended that the cost of natural gas production kept low, in the range of $0.5 – $1.0 per million BTU, preferably $ 0.5 per million BTU. This could be achieved through the production from relatively small number of wells that are capable of sustained high-volume production. The recommendations were based on the studies conducted in 32 countries to see the production cost and it was concluded that there are 665 trillion cubic feet of gas, which could be developed at a cost less than $1.0 per million BTU. *(Reference: Assessment of costs and benefits of flexible and alternative fuel use in the US transportation sector: Technical report nine).*

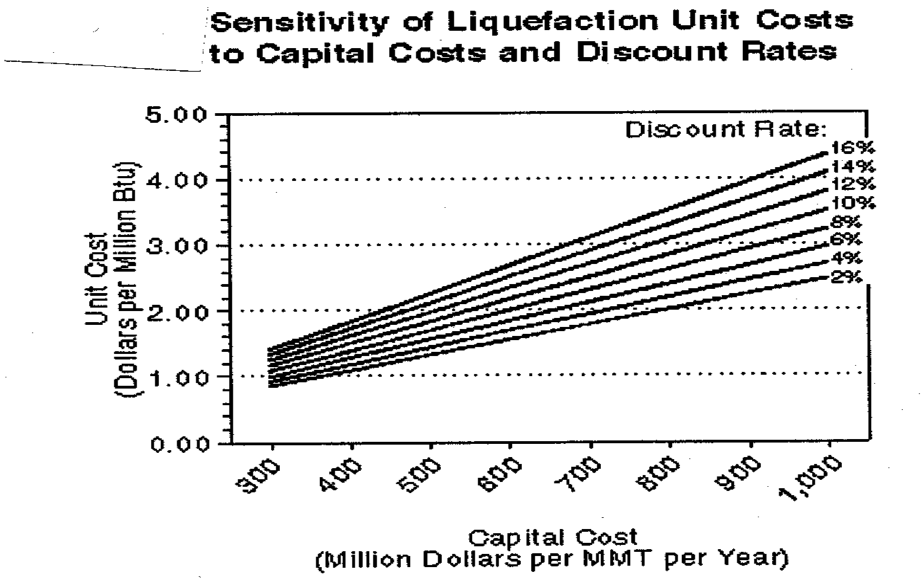
On the other hand, if natural gas production yields significant volumes of condensate or natural gas liquids, the reserves from petroleum co production should be sufficient to cover the cost of natural gas production, permitting the project to benefit from low natural gas feedstock prices. The extracting of liquids and condensates at the terminal is usually profitable but involves an arithmetic cost. Approximately 10% of the gross gas production undergoes "shrinkage" in the form of extracted liquids and non-hydrocarbon gases. Hence, the report also recommended that gross production and reserves should exceed the volume of gas delivered to the liquefaction plant by the amount of shrinkage.

Liquefaction plant:

One of the most expensive elements of the project is the liquefaction plant. As a thumb rule \$500-\$900 of the capital cost (\$1.6-2.0 billion) for 2.5 to 3.0bcm/y capacity seems to be the current trend. The exact amount depends on several site-specific factors and the size of the project, with larger projects having lower costs.

The distribution of the capital cost depends on the financing details and inflation but primarily on the targeted expected rate of return on capital.

Fig 3.2 Sensitivity of LNG transport costs to capital costs



MMT = million metric tons of capacity.
Source: Energy Information Administration, Office of Integrated Analysis and Forecasting. Calculated on the basis of a 30-year amortizing loan and operating costs of \$0.15 per million Btu processed plus 7.5 percent of capital cost annually.

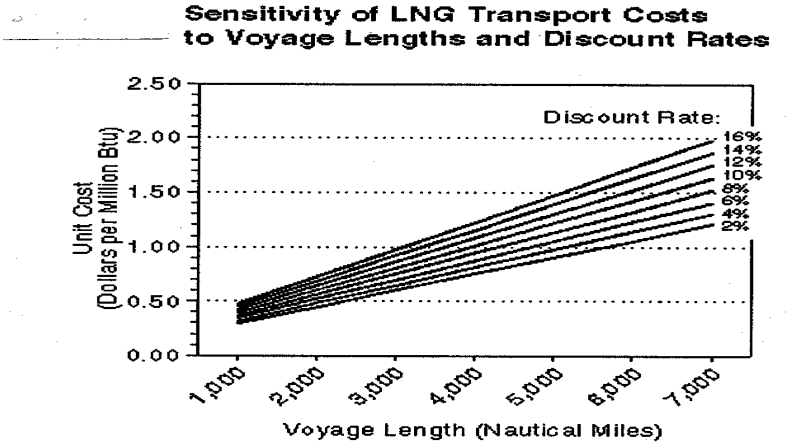
Typically for the liquefaction facility as per the same report the acceptable unit cost is \$2 to \$3.0 per million BTU although high capital costs and target rates can affect the project. The operating costs are relatively low, however, the liquefaction process is highly energy intensive viz. 8 - 9 % of the gas delivered to an LNG plant is used as fuel to liquefy the rest. *(Source: M. An Adelman and M. Lynch, " Natural gas supply in the Asia - Pacific basin", in Massachusetts Institute of technology centre for Energy policy research).*

As compared to the liquefaction cost the regasification cost is less. Presently these regasification facilities are set up in the consuming markets. These costs maybe higher today where new markets like China and India are entering the scenario, as it will involve infrastructure investments also. A US department of energy study estimated the capital cost of new plant as approximately $700 million for a 500 million cubic feet per day facility, which is equivalent to $ 0.56 per million BTU. Regasification energy requirements consume 2.5% of the delivered gas.

LNG tankers and voyage distances:

LNG tankers are complex, specific and costing in the range of $200-$260 million (although Japan /Korea = $170/$160 million) for each 135,000cubic metre capacity. The number of ships is a function of the distance between the exporting (ex Gulf) and the importing terminals (West Coast India). The unit cost of marine transport is primarily a function of the capital cost of the tankers, the financing terms, acceptable rate of return for the tanker owners and the voyage distances. Besides the cost of bunker fuels, the costs of arrangement of the spare transport capacity are also considered when dedicated tankers are refitted.

Further the LNG requires to be cooled. This is done by the process of evaporation of part cargo called "Boiloff " and then burning the evaporated fraction as boiler fuel. It is understood that per day approximately 0.15 to 0.25 % of the LNG is evaporated, during which the tanker travels 480 nm. Thus moving of LNG on a distance of 7000 nm e.g. from Gulf to Japan 3.6 % of LNG will be consumed.



Source: Energy Information Administration, Office of Integrated Analysis and Forecasting. Calculated on the basis of a 30-year amortizing loan; service with tankers with capacity of 135,000 cubic meters of LNG, each costing $260 million, speed 19.5 knots, 1.7-day port turnaround, in service 340 days per year, and fuel price $24 per barrel; and operating costs of about 10 percent of capital cost annually. Does not take into account requirements for spare tankers or scheduling issues.

Fig. 3.3 Sensitivity of LNG transport costs to voyage lengths

3.8 Natural Gas pricing:

Since natural gas is being considered as a competitor as well as an alternative to other fuel source it concerns a large market. This includes the fuel oil industry, power generation, residential / commercial sectors and the gas market. However, in practise the pricing is relative to competing fuels as well as the government policy.

In India, for the oil industry the government has a price control mechanism and administered rates for the fuel and the products. In 1997 it allowed the use of naphtha as a fuel source for the power plants. Presently the government is not only encouraging natural gas as the option for power generation but is also playing a prominent role by its participation in joint venture, privatisation, foreign participation and setting up a shipping policy to encourage national shipping companies as carriers. Thus it can be said that governments have an important role to play in promoting gas usage and natural gas has to be priced competitively with alternate fuels if markets are to be penetrated, secured, retained and expanded

Table 3.7 LNG Prices per BTU

Current US $ per million Btu

Year	LNG *Japan c.i.f.*	LNG				Crude Oil *OECD countries c.i.f.*
		EU c.i.f.	UK**	USA***	Canada***	
1990	3.64	2.82	-	1.64	1.05	3.82
1991	3.99	3.18	-	1.47	0.89	3.33
1992	3.62	2.76	-	1.77	0.97	3.19
1993	3.52	2.53	-	2.10	1.69	2.82
1994	3.18	2.24*	-	1.92	1.50	2.70
1995	3.46	2.37*	-	1.69	0.89	2.96
1996	3.66	2.43*	1.84	2.76	1.12	3.54
1997	3.91	2.65*	2.03	2.53	1.36	3.29
1998	3.05	2.27*	1.92	2.08	1.42	2.18
1999	3.14	1.73	1.64	2.27	2.0	2.96

** Based on information supplied from several sources ** Source PH Energy *** Natural gas Week BP Amoco Statistical Review of World Energy 2000.*

Table 3.8 LNG import price range per BTU region wise

Market	Quantity (MMT)	Price range US $ / mm Btu
Asia	56.3	3.05 - 3.81
Europe	15.6	2.36 - 3.05
North America	0.9	2.52 - 2-60

Source: LNG express LNG market statistics

From the price table 3.8, the decline of the LNG prices is considered by analysts as a positive contribution to the trade. LNG prices could fall and the market for premium-priced “clean” fuels may expand. For LNG to gain market share, the crude oil prices should be approximately $20 per barrel and coal prices about $ 40 per ton (Oil and coal prices in Appendix 3 Comparative prices of fuel)

Ship costs are not considered as a big cost factor in the decision of a LNG project going ahead. (Source: Japanese set to benefit … from LNG market Mathew Flynn). The negative side is buyers prefer shorter charter periods as against the 20 years. The life expectancy span of the ships is nowadays longer. Through intensive maintenance programmes ship owners are trying to keep the span to 40 years or more. A reference to this is Shell’s Nigeria project.

The participation of the shipping lines is an interesting point based on several issues:

i. Does the seller want to sell ex-ship, with the ownership of the cargo transferring at the port of delivery?

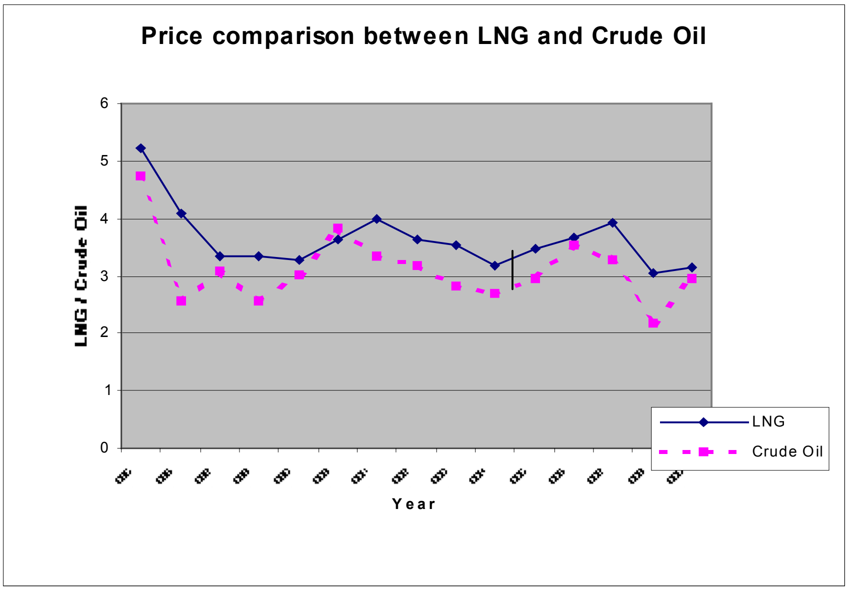
ii. Does the buyer want to purchase FOB as against the traditional CIF prices, thereby taking control of the transport leg?

The participation of the shipping component is often determined during the lead-time in the project e.g.

a. Japanese shipping line recently took equity participation in SK Shipping vessels chartered for Korea Gas.

b. Cross trades of Indonesia cargo shipped from Pertamina to Chinese Petroleum in Taiwan and Enron Dabhol project in India.

Further, trading houses are also showing keen interest by co ordinating the transport of the package and acting as intermediary between the buyers and suppliers. This is a change from the traditional involvement where the houses only played the role as traders. Today they are extending their involvement through equity participation. e.g. the role of Mitsubishi, Mitsui, Marubeni and Nissho who act as sellers, traders and agents for Japan import procedures.



Source: Compiled from BP Amoco Statistical Review 1999

Fig. 3.4 Price comparison of Crude oil and LNG

From Fig. 3.4 an interesting feature that can be observed is that the peaks seem to have about 1 year difference while the trough occur at the same time. This could be due to the declining trend in elasticity. (Detailed working in appendix 7 and explanation in section 3.7.2) From the values obtained one can also observe that there is a decline in the value of r the co efficient regression for year 1 to year 3. Thus when crude oil prices decline the LNG prices which are based on Crude oil also decline to make it a competitive and a substitute fuel source. However, there is a base limit (past years shows $ 2.0 per BTU as minimum) beyond which LNG is unviable and economically unfeasible. Further the contracting nature of the agreement could also play a role resulting in the above nature. These contracts are long term (25 years) with the pricing being determined for periods (every 5 years on c.i.f. basis). However, it must be noted that the above conclusion by the author is based on the findings of a small sample range and hence the above scenario must be closely monitored for a longer period of time for a more final definite conclusion.

Also from the graph, in Fig. 3.4, two critical issues come to the authors mind. Firstly at what price level, at the input to the national transmission grid can importers afford to pay and still be able to sell the contracted quantities in a competitive market. Secondly, if the determined prices can result in an adequate return to producers after deduction of production and transportation costs so as to continue export of gas. Although these vary from case to case, the amount an importer is expected to pay can be affected by the following factors:

- The age, capacity and expected utilisation rate of existing distribution system.
- The distribution of existing and incremental natural gas supplies to alternative markets.
- Security and financial considerations.
- The structure of domestic taxation on energy products.
- Expectations about future price developments of competing fuels like LPG oil.

For the producers the decision on whether the export gas is based on factors such as

- Cost of developing new reserves and the production.
- Fiscal and price regime.
- Alternative uses.

An issue that arises is whether the gas producers are demanding a price, which is comparable and competitive to prices in the consumer market. During the mid 80's to 1991 (from graph 3.4) the LNG price is not related to the crude prices. This is because pricing had become a highly political issue as producers tried to increase their export prices to oil prices on a thermal equivalent basis. This resulted in discrepancy and disputes between the exporters and importers and also involved the national government.

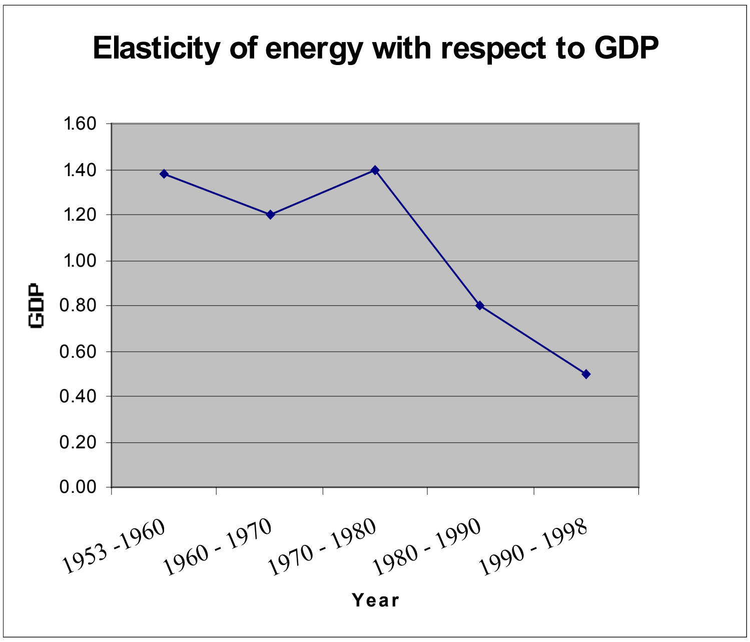
3.8.1 Co efficient co relation and regression of LNG / Crude Oil:

Presently the LNG prices are linked to the crude oil prices as seen from the graph Fig. 3.4 above and the co efficient co relation calculations. Thus high oil prices would result in higher LNG prices. The value for r = 0.81 for the period 1990-1999 however, indicates that there maybe other factors that also influence the pricing. Workings as in Appendix 6 (1985/90, 1990/95 and 1995/99) show r the co efficient relationship closer to 1 in the latter period suggesting a strong co relation for the term period 1995-1999. This according to the writer is explained as follows: It is understood that besides the political influence as explained above during the periods of 1980 to 1986, imported natural gas prices were relatively inelastic to demand due to inflexible contract provisions and the imbalance position between the buyers and sellers. This resulted in LNG pricing being uncompetitive and it was only in 1991 that natural gas was again priced in relationship with oil as also seen through the correlation coefficient of 0.91 (1995 - 1999). The co efficient co relation and the risk management workings are enclosed below.

3.8.2 Elasticity of LNG pricing in relation to Indian scenario:

This is based on the interaction between energy-economy that is generally linked. The working on the elasticity of LNG pricing (detailed calculations annexe 7) as well as from the fig.3.5 below indicates a declining trend as well as inelasticity.

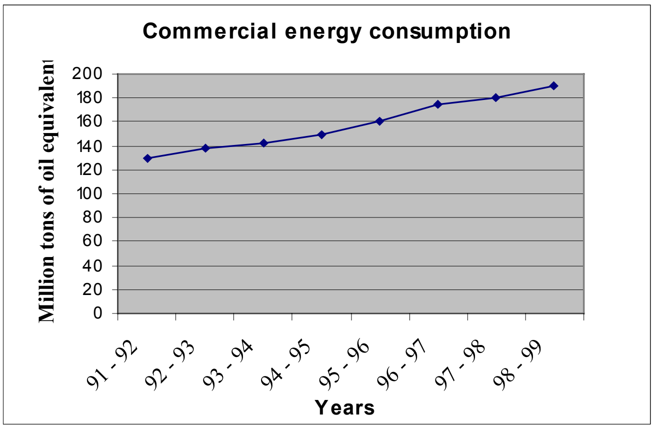
From the writer's view point this can be explained as follows: The Indian economy has undergone structural changes i.e. during '91 - '98 the share of agriculture in the GDP declined from 32.8 % to 28.7 %, while the share of industry and service increased by 1.4 % to 2.7 %.



Source: Bhattacharya and Gupta (1998)

Fig.3.5: Elasticity of energy with GDP

In addition one of the factors that affects the energy demand is the growth of population, especially the increase in the proportion of urban population. According to the World Report (WRI '98) it is estimated that the Indian population of 916 million will grow to 1394 in 2025. However, the noteworthy feature is the higher growth of urban areas as against rural. From 216 million people the figure is expected to rise to 415 million by 2015 according to MoHA. Due to the increased work related shift, there has been a rise in the per capita income ($370 in 97 / 98 as against $ 225 in 93 / 94 prices according to the MoF 1999 and World Bank 1999). The cumulative effect of the above has been the rapid increase in energy consumption.



Source: Compilation from Ministry of Finance (1999) & Economic Survey (1998/1999)

Fig. 3.6 Commercial energy consumption

As further, understood from the Economic Survey report, rather than the price levels, the availability considerations, are important determinants of energy and the energy GDP elasticity is often used as an indicator. Thus the declining trend of energy – GDP elasticity is due to

i. The structural changes in the economy.

ii. The changing pattern of demand.

iii. The penetration of efficient and energy saving technologies.

The changing pattern of demand has been due to fuel substitution in the industry, domestic and transport sector. Natural gas is being increasingly considered as a fuel / feedstock in fertiliser, petrochem, power, sponge – iron industry and also in the transport sector.

The elasticity reflects the low per capita commercial energy consumption as well as substitution of traditional fuels by commercial energy forms.

To conclude the contributing factors for LNG pricing and inelasticity is

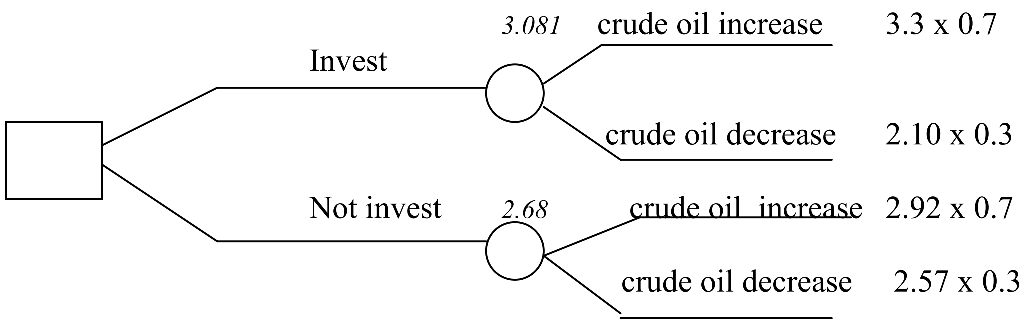
- the growth and structural changes in the economy
- the increasing per capita income
- the continuing shift from non commercial forms of energy
- increased urbanisation
- the shift towards thermo dynamically efficient fuels such as natural gas.
- the technological changes in the energy sensitive industries.

(Source: Bhattacharya A.A, Gupta S.P (1998). Deregulation in energy sector. Indian experience and perspective. MoF (1999), Economic survey (1998/1999) New Delhi; Ministry of Finance. Government of India. MoP1999. Annual report 1998 / 1999. New Delhi; Ministry of Power, Government of India.WRI, (1999). World Resources 1998 / 1999. New York World Resource Institute).

3.8.3 Decision making in investments related to LNG pricing and Risk Management:

A decision to invest based on the pricing per BTU maybe necessary. The situation of uncertainty is about the crude oil prices, which determine the LNG price. If the crude oil price increases and investment is made in the project then the price per BTU for LNG could be approximately $3.30. However, in the event of crude oil prices declining the LNG price negotiable may be only $2.10 per BTU. In the event that investment is not made in the project and crude oil prices increase the LNG price per BTU would be approximately $2.92 based on historical data and $ 2.57 per BTU if the crude oil prices declined. The information as per the OPEC conference – Vienna (June 2000) the probability of a change of the prices increasing is 70 % whilst it remaining same is 30 %.

Thus pay off is as follows:



Combining the results of sensitivity analysis and the calculations of risk management can greatly assist decision makers on whether to invest or not in the project.

Decision tree and Sensitivity analysis

Scenario 1

LNG prices	Prob.	Exp. Payoff	Crude oil in.	Crude oil dec.	Invest / No invest
3.3	0.7	2.310	2.940	2.815	
2.92	0.7	2.044			**Invest**
2.57	0.3	0.771			
2.1	0.3	0.630			

Scenario 2

LNG prices	Prob.	Exp. Payoff.	Crude oil in.	Crude oil dec.	Invest / No invest
3.3	0.6	1.98	2.82	2.78	
2.92	0.6	1.752			**Invest**
2.57	0.4	1.028			
2.1	0.4	0.84			

Scenario 3

LNG prices	Prob.	Exp. Payoff.	Crude oil in.	Crude oil dec.	Invest / No invest
3.3	0.4	1.320	2.580	2.71	
2.92	0.4	1.168			***No invest***
2.57	0.6	1.542			
2.1	0.6	1.260			

Sensitivity analysis

Assume α is the probability that the crude oil prices will increase

$1-\alpha$ is the probability that the crude oil prices will not increase

From the above the break even is :

$$3.3\,\alpha + 2.1\,(1-\alpha) = 2.92(\alpha) + 2.57(1-\alpha)$$

$$3.3\alpha + 2.1 - 2.1\alpha = 2.92\alpha + 2.57 - 2.57\alpha$$

$$0.85\alpha = 0.47$$

$$\alpha = 0.55$$

From the calculations and sensitivity analysis the breakeven point is 55 %. If the probability of crude oil prices increasing is less than 55 % the expected payoff is low and it may not be worthwhile investing. However, from the 3 scenarios, since small moves in the figures do not incur a change in the decision to invest the option is stable and investing is recommended. Further, from workings of the risk management of the project the co efficient variation of 0.04 also suggests that is not a very high risk project. As the estimated payoff or losses and especially the estimated probability are given often subjectively based on experience and judgement (in the above case proceedings of the OPEC meeting – Vienna, June 2000) an evaluation of the effects of errors is absolutely necessary.

3.9 Summary: Presently LNG projects compete against coal and petroleum products in power generation markets and potentially against middle distillates and LPG in smaller premium residential markets. Although LNG is more expensive as compared to other fuels the advantages as a cleaner fuel places it as a fuel of the future. Improving technology or transportation methods could reduce the capital cost.

The gas prices although higher than coal or oil on a BTU basis, is more or less declining or stable since 1995. For the gas to be competitive, in Asia, the LNG import prices should be negotiated in the range of \$ 3.05 to \$3.81 / mm BTU. In Japan the actual delivered cost of LNG under a mix of spot and long term contract is about \$3 - 4 million per BTU and can be considered when pricing LNG for India. *(Source: Asian LNG prices and World Gas Intelligence 1997).* To date most of the LNG contracts are CIF based. FOB contracts if negotiated could give the buyer freedom to pick up spot cargoes as and when convenient.

LNG pricing is based on Crude oil prices more relatively since 1995 with a co efficient co relation of $r = 0.91$. The inelasticity of LNG for India is primarily due to the growth and structural changes in the economy, technological changes in the energy sensitive industries and the substitution of traditional fuels. The coefficient variation of 0.04 suggests that it is a low risk project.

The framework of the Convention on Climate change can affect the LNG market. Governments wishing to limit national emissions of greenhouse gases might look with favour on natural gas for efficient and economic power generation. Burning natural gas emits less carbon and sulphur di oxide than other fossil fuels, but the process of liquefying, transporting and regasifying of LNG is very energy intensive (fuel consumption increases by 15%). However, markets for premium priced “clean” fuels is expected to expand in current and potential consuming countries with increasing public concern about air quality or greenhouse gas emissions.

Chapter 4

Natural Gas Hydrate as an alternate form for LNG transportation

4.1 Natural Gas Hydrate: A new dimension

A comparison with other fuel sources on a cost basis may not always put LNG on an upper edge as was also seen in Chapter 3. A critical factor would be to try and reduce the capital costs to make it a competitive source. The technology on the landside is more or less standardised and has been used for several projects. This chapter will try and analyse the implications if LNG is transported in another form namely as a frozen hydrate. Although not applied today because it involves diverting from the traditional, proven methodology thereby involving risks that most projects are hesitant to undertake due to high capital costs.

From Chapter 1-The world-wide demand of natural gas is increasing continuously especially in Asia Pacific and Europe. Further it was noted that most of the reserve centres are at distant centres away from the consumers resulting in transportation over increasingly longer distances. Thus a reduction of capital costs would play a significant role to facilitate the use of LNG as well as position it better as against the competitive fuels. Following opinion/comments by the industry's major players indicates the importance of trying to look at a methodology to reduce costs further.

At the 5th International Offshore and Polar Engineering conference – The Hague, 1995 Exxon remarked that the development of the natural gas industry in the next 15 years or so is likely to be dominated by costs. It was also expressed that "The industry must continue to reduce project costs, keep gas competitive and obtain prices in line with full market value". Further Mobil's Commichau stated that " The gas industry today faces tremendous challenges, which are mainly of an economic nature and that increasing volumes have to be transported over increasing distances which can be profitable if costs are reduced and prices are increased".

LNG technology is in essence mature and since one cannot beat the principle of thermodynamics it is unrealistic to expect a dramatic decrease in capital costs from a single process improvement. Therefore LNG capital cost reduction requires to be driven by contributions in all aspects of the projects. One of the major constraints is the high LNG technology cost, with little possibility of significant reduction through its technology improvements. It thus becomes pertinent to look for an alternative, which makes one consider the transportation as **natural gas hydrate,** thus leading to a new dimension.

4.2 Natural Gas Hydrate (NGH) as a new method of transportation:

This method involves storing and transporting of natural gas at atmospheric pressure. The hydrate is refrigerated at about -15^0C and then kept at near adiabatic conditions. The hydrate remains stable, making it possible to transport natural gas in an insulated bulk carrier to distant gas markets. This process is presently under patent by Gudmundsson (1990) Norwegian Institute of technology, Trondheim, Norway. Studies conducted by Gudmundsson and Parlaktuna (1992), Gudmundsson et al. (1994) on the storing and transporting of NGH showed that one of the properties of NGH is it tends to decompose. Hence it is necessary to use high pressures to prevent decomposing which results in high equipment costs. As a result the use of NGH for large scale storing and transport did not receive much attention.

In 1995, Berner further proposed that NGH could be transported by ship at ambient temperatures in pressure tanks of reinforced concrete, 14.5 bara pressures to prevent the gas from decomposing. These tanks must be insulated (12" insulation) and his studies showed that for a voyage of 2500 km at 15 knots, of approximately 4 days, the NGH decomposed less than 1 % as a result of heat transfer from outside. Based on the above, an alternative to the high pressure is necessary. According to the same studies, refrigeration of the hydrate to their equilibrium temperature (instead of ambient) at atmospheric pressure i.e. to -32^oC can be considered to prevent the NGH from decomposing. However, although technically feasible, the transportation and storage at the temperature of -32^{o}C may not be economically feasible.

Subsequent trials at the Norwegian Institute Technology (Gudmundsson et al) showed that the NGH does not require to be refrigerated to equilibrium temperature, for stability, but it would be sufficient if storage and transportation is conducted under adiabatic conditions. Adiabatic conditions are those where practically no thermal energy is allowed to enter the system, thereby preventing rapid decomposition (similar to melting). Thus the NGH is deficient of thermal energy necessary to convert it into natural gas and water.

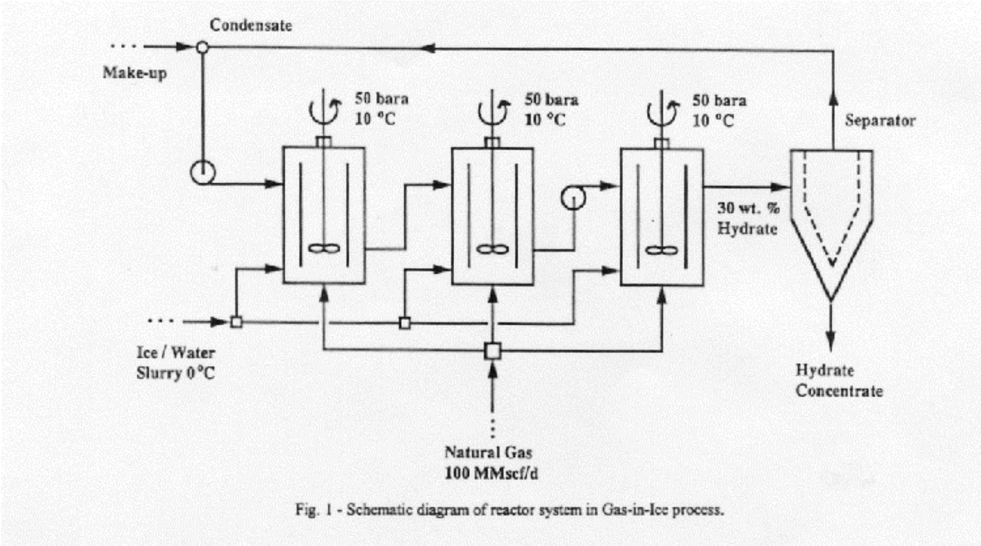
The above trials by Gudmundsson et al also reported that NGH when stored adiabatically at atmospheric pressure above freezing point of water would decompose slowly into gas and water, as thermal energy is required. This energy can be transmitted from the adjacent particles of the hydrate. However, it will also result in gradually cooling down the hydrate but conductivity is relatively lower. The breakdown of the gas is even slower when stored adiabatically at atmospheric pressure below freezing point of water. The storage temperatures can thus range from -5^{o}C to -15 ^{o} C. Also, when the hydrate decomposes it forms a protective layer thereby further reducing the process. (This is proved, as one of the samples was stored at -6 ^{o} C for 2 years without any decomposing. *Source – Experimental work reported by Gudmundsson and Parlaktuna (1992), Gudmundsson et al (1994) - Norway. Davidson et al (1996) and Handa (1996) Canada. Ershov and Yakushev (1992), Yakushev and Istomin (1994) –Former Soviet Union).*

4.3 NGH process / Gas - in - Ice process:

The process was conducted as a study project by Norwegian Institute Technology and is addressed primarily through 3 steps namely

i. Production ii. Separation iii. Transport

i. **Production**: This involves extracting sufficient thermal energy when NGH is formed. The production of NGH occurs in a tank reactor with continuous stirring and where natural gas is injected into liquid water. The reactor operates at 10^{o}C temperature and 50 bara pressure after which the ice/ water slurry is injected into another reactor for cooling and forming the concentrate. The flow diagram Fig. 4.1 below shows the reactor stages:



Source: Transport of NGH as frozen hydrate. Norwegian Institute of Technology and Aker Engineering

Fig. 4.1 Schematic diagram of Production process

At each stage there is an increase in the concentrate (hydrate/liquid) from 10 to 30% and the ice/water slurry is also used for cooling. This system of ice /water cooling is considered as a critical step in the development of a cost-effective Gas-in-Ice process. The 50 bara reactors are considered simple to design and are of reduced costs since no heat transfer pipes or jackets are required.

ii. **Separation:** This involves how best to separate the solid hydrates from the liquid water of similar density. A combination of separators (cyclone) and decanters can be used. The principle condensate of carrying lighter fluid rather than liquid water can be applied. The mixture, which enters the vertical separator as a concentrate, undergoes separation and is pumped out subsequently minus liquids. More than one decanter can be used to obtain as low a water content of the hydrate as possible. This dewatering is followed by drying of the hydrates and finally refrigeration at -15 ^{o}C and reduced pressure. However, the similar densities between the hydrate and water can be an obstacle. The flow diagram in Fig. 4.2 below shows the separation process.

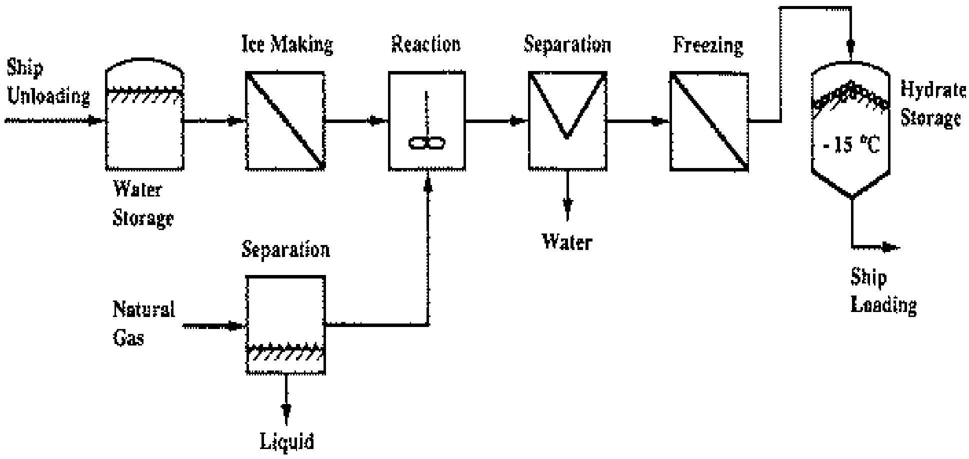


Fig. 2 - Schematic diagram of Gas-in-Ice production process.

Source Transfer of Natural gas as frozen hydrate. Norwegian Institute of technology Aker Engineering

Fig. 4.2 Schematic diagram of Separation process

The frozen hydrate at -15^{o}C is similar to ordinary ice and contains 15wt % gas and 85 % water. The handling and processing regulations are the same as oil and gas and the hydrate technology is inherently much safer than LNG.

iii. **Transport:** The transportation and storing requires the same conditions as the hydrate in separation. The NGH remains stable at atmospheric pressure when kept frozen at near adiabatic conditions. It is possible to store the hydrate in rock cavern and other large volume containers and is less expensive than LNG. Regasification involves simple melting by direct contact with warm water. The gas is compressed, dewatered, stored and as required transported to a gas distribution net. The separated water can be loaded to a hydrate ship since it contains seeds of hydrate crystals which will facilitate quick reaction rates in the production plant. The above process also called Gas-in-Ice process operates at temperatures close to ambient conditions such that the heating and cooling will be energy efficient.

4.4 Capital cost of transportation:

It is true that NGH as compared to an equivalent amount of LNG occupies a large volume. This is approximately four times larger based on the following assumptions that LNG contains 600Sm^3(standard cubic metre) and hydrate 150Sm^3 of natural gas. Thus in terms of volume capacity the NGH ships must be 4 times larger than that of LNG for the equivalent quantity of gas to be shipped. The size and cost in my opinion could be constraints when considering the frozen hydrate.

Typical LNG ships are 125 000 m^3 and 135 000 m^3. Studies conducted by Nagelvoort and Tijm (1994) and Hveding (1995) proved that there can be hydrate ships at least twice the size i.e. 250 000 m^3 and are simply insulated bulk carriers which do not require refrigeration. Thus the ships would be less expensive as compared to LNG ships. The capital cost of LNG ships (18 knots) is presently 240 million USD for 125 000 m^3 and 200 million USD for 135 000 m3 ships. (Further accuracy depends on exchange rates. *Source: Fairplay Feb. 25, 1999. Science outstrips LNG investment. P. 23*). For capital cost calculation purposes 125 000 m^3 is considered.

An experiment was conducted at Snohvit field (Norway-Institute of Norwegian Technology, Shell, and Aker Engineering) and the capital cost working is based on this study. Thus, for hydrate ships, as they are capable of transporting only half of the gas as compared to LNG, hence ships of 250 000 m^3 would be necessary. Based on the chemical properties, the bulk hydrate porosity of 16.7 % (1/6) was assumed which required a carrying capacity of 300 000 m^3 tonne. A bulk hydrate carrier of 250 000 TDW with a density of 928.5kg/m3 and a weight of 232,125 tonnes was therefore considered by them for capital cost calculation purposes. The excess 7 % prevents any biased favour towards hydrate ships. Based on this the cost break up for NGH transportation is as per table 4.1

Table 4.1 Cost Break up of NGH transportation

Particulars	Million USD
250 000 TDW bulk carrier	55.4
Insulator (100 mm thick)	3.6
Loading and unloading equipment	10.0
Total cost	69.0

(Source: Studies based on the transportation from Snohvit field)

Assuming loading and unloading of both types of ships including unexpected delays as 6 days and with 350 days operational on a transportation distance of 3500 nautical miles, 3 LNG ships can deliver about 3.6 billion Sm^3 of natural gas as compared to 7 NGH ships delivering 3.7 billion Sm^3. It should be noted that the speed of NGH ships is assumed 16.7 % less than LNG ships. Therefore, the hydrate ships operate at speeds of 15 knots or less and still deliver the same volume.

From above 3 LNG ships will therefore cost 720 million USD whereas 7 NGH ships cost 490 million USD Thus the hydrate ships capital cost is 170 million USD less than LNG ships, resulting in a saving on the capex on capital cost of 24 %. If transport distance of 3000 nautical miles is used instead of 3500 nautical miles, the 3 LNG ships and 7 hydrate ships can transport more gas per annum. Each LNG ship will make 18 voyages per annum and NGH 16 voyages per annum and the total transport capacity would thus be 4.1 and 4.2 billion S m^3 respectively.

4.4.1 Capital cost of LNG chain:

The procedure for LNG is more or less a standardised general procedure. According to this method for the LNG project of a quantity of 4 billion Sm^3, 3 nos. of 80 000 m^3 each LNG tanks were required as per the study by the Norwegian Institute Technology. The detailed capital cost for a 4 billion Sm^3 based on 2 LNG trains is as per Appendix 5, Table 5.A Capital Cost break up resulting in a total erected plant cost of $ million 1190. The LNG chain (production, shipping, and regasification) for a 4 billion S m^3 p.a. is estimated as 2677 million USD a breakdown is as per Table 4.2 below. From table 4.2 it can be said that the LNG production cost equals $ 886 USD per tonne of annual capacity. Similarly capital cost for shipping being $ 378 USD per tonne,

Table 4. 2 Capital cost for 4.0 billion S m^3 LNG chain

Particulars	Million USD
LNG production	1489
Shipping	750
Regasification	438
Total	2677

Source. J S Gudmundsson and F Hveding , Norwegian Institute of technology, Aker Engineering.

regasification $ 221 USD per tonne with a total of $1485 USD per tonne of annual capacity.

4.4.2 Capital cost of NGH chain:

According to the same study this chain, consists of production, transport and melting. The hydrate at -15 ^{o} C is similar to ice and can be formed and handled easily. It was found that the hydrate contains about 15 wt. percent gas and 85 wt. percent water, with the volumes of natural gas in 1 cubic metre of hydrate being approximately 150 cubic metre. The regulations and procedures used in oil and gas handling and processing are applicable to NGH (Gas-in-Ice) process and is also considered safer than LNG technology.

For the estimation of the capital cost of NGH the plant capacity of 4 billion Sm^3 of natural gas is also considered. In the LNG chain initially the rate was divided into 2 trains, however in the hydrate plant, it is divided into 4 trains, each with a capacity of 1billion S m^3. The reason for this is because of the large liquid volumes involved. An implication of the small plants is it makes it possible to construct and operate more accurately to the actual increase in the natural gas demand.

The capital cost of the hydrate process unit is $103.02 million and the cost of the main equipment is estimated as $235 million (*Source Institute of Norwegian Technology and Aker Engineering.* Detailed cost break up in Appendix 5 table 5.B, 5.C). Bulk material and plant cost is estimated as 150 % of the equipment cost, according to the recent off shore cost relationships. Marine facilities including engineering and management cost results in the plant cost to $735 million. Since it is a new process, a contingency of 30 % is added, resulting in a total cost of $ 956 million. This is the capex of the 4 billion S m^3 per annum assuming NGH as a greenfield installation of production process and facilities. The capital cost thus is as shown in Table 4.3.

Table 4.3 Capital cost for 4.0 billion S m^3 NGH chain

Particulars	Million USD
Process	955
Shipping (5500 km)	560
Melting	480
Total	1995

Source. J S Gudmundsson and F Hveding, Norwegian Institute of technology, Aker Engineering

4.5 Comparison of capital costs for 4 billion S m^3 of LNG and NGH chain

Table 4. 4 Comparison of Capital cost between the LNG and NGH chain

Particular	LNG		NGH		Difference	
	Million USD	%	Million USD	%	Million USD	%
Production	1489	56	955	48	534	36
Shipping	750	28	560	28	190	25
Regasification	438	16	478	24	-40	- 9
Total	2677	100	1993	100	684	26

The above table 4.4 shows the comparison of the capital costs of the LNG chain and the NGH chain and the figures presented illustrate the savings attainable by using hydrate technology instead of the liquefaction technology.

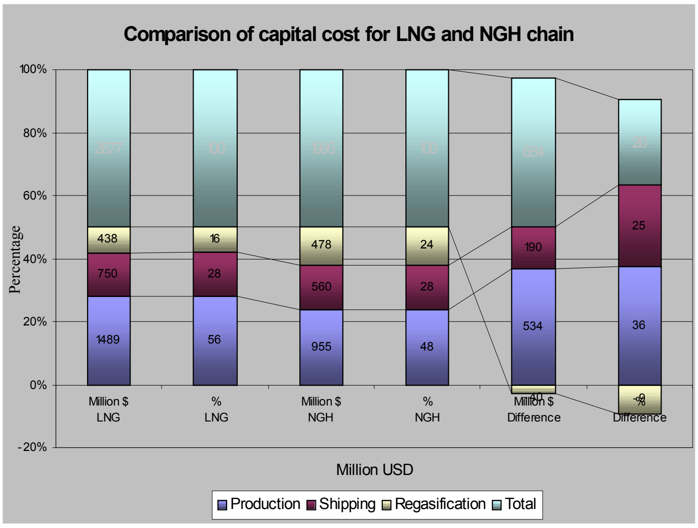
From Fig. 4.3 graph, and table 4.4 it can be concluded that the capital cost values for NGH is much less than LNG namely 25 % in LNG shipping, 36 % less in the production process however 9 % more in the regasification process with an overall saving of 26 % which is substantial. However, a consideration on the operating costs when worked out may result in a reduction of this advantage on the capital costs.

4.6 Direct cost comparison for LNG and NGH ships:

This could broadly be divided into Operating and Voyage costs. The operating costs would include

i. Crew: e.g. Special training necessary to ensure safety specifications, high manning levels, salaries, travelling, and social securities

ii. Insurance: e.g. Hull and Machinery to ensure against damage and loss. P & I against third party liabilities.



Source: Compiled from calculations of table 4.4-Comparison of capital costs.

Fig. 4.3 Capital cost for LNG and NGH prices

iii. Insurance: e.g. Hull and Machinery to ensure against damage and loss. P & I against third party liabilities.

iv. Maintenance: It constitutes a major section of the operating costs. Some of the statutory requirements by the government and classification societies also necessitate dry docking atleast once every 5 years for a periodic survey.

v. Lubes

vi. Administrative costs.

The voyage costs may consist of

i. Port charges: These vary from port to port depending on the installations, ship size, geographical location etc. However, in view of the specialisation and higher safety standards LNG tankers require stronger and high powered tugs which also result in an increase of the port charges.

ii. Costs of boil off gas: The boil off gas is often utilised as the fuel for the main engines and the total quantity depends on

- Volume of cargo being carried
- Distance of voyage lengths
- Type of containment system

The boil off gas, when steaming is available in ballast and the loaded tanks. However in port the requirement is met entirely by bunker fuel oil and marine diesel oil. According to the Fairplay report on LNG Carriers the break up is as follows:

Table 4.5 Operating costs for LNG ships

Particulars	Total cost over 20 years Million US $	% of total operating costs
Crew cost	35.2	12.0
Stores and tools	27.3	9.0
Boil off	53.2	2.0
Gas loss during loading	12.9	17.0
Vessel inerting costs	5.9	2.0
Maintenance and repair	53.5	18.0
Insurance	64.5	21.0
Port Charges	31.7	10.0
General overheads	15.2	5.0
Total	**304.2**	**100**

Source. Fairplay report on LNG carriers

Thus from the above table 4.5 the operating costs per annum for a LNG is approximately $ 15 million US per annum. With the requirement of 3 LNG carriers the total operating cost will be approximately $ 45 million. In comparison the NGH ships being simple bulk carriers would not require specialised system however according to the sensitivity analysis conducted by the author it is necessary that operating costs are at approximately $ 8 million or less to make the project much more viable. It would otherwise result in NGH transportation being more expensive to LNG by 19 %. This may be offset against the capital cost thereby reducing the competitive advantage. Further, the bunker quantities and the prices will also have an impact on this advantage. In the author's view this operating cost offsets substantially against the 24 % capital cost advantage and could be one of the reasons, which has discouraged investors as well as the implementation of this mode. However the NGH transportation does have some advantages which could be considered when making a decision namely:

- NGH requires simple carriers as compared to the LNG specialised system.
- It allows for more flexibility in the event of the change of business based on the features of the vessel.
- Specialised training of the crew may not be necessary as compared to LNG.

- Safer transportation at temperatures of - 5^o to - 15^oC as against -161^oC for LNG.

The major impact of NGH on the industry is the possibility of long distance gas transport, a field where it threatens to supersede LNG. The problem is accepting the theory of NGH and converting it into a commercial reality. Presently a project for trapping associated gas and long distance transport is being conducted by Shell along with Aker Engineering and Norwegian Institute. The first commercial unit is proposed, designed and will be built by 2003.

4.7 Summary:

It is technically and economically feasible to transport the natural gas in the form of hydrate. However, the hydrate must be stored near adiabatically at -15^oC and the ice / slurry mixture supplied to the reactors. It is an advantage for the hydrate since it remains stable at a pressure of one atmosphere and above mentioned temperatures. This implies gas can be carried in refrigerated bulk carriers as compared to LNG ships where gas temperatures are about –163^oC and specialised ships are required. The total capital cost of hydrate production and melting processes are about one fourth 25 % less than LNG liquefaction and regasification processes. However, the running costs may lower this advantage as these higher costs (approx. 19 %) are offset against the capital costs. It could be one of the reasons, which have attributed to this methodology of transportation not being adopted till date.

Besides the significant capital cost difference it is found that NGH technology is much safer. The technology is relatively uncomplicated. It is likely to provide local employment. The LNG technology in comparison is highly specialised and is dependant on equipment offered by few manufacturers especially the liquefaction heat exchangers that are also expensive. The argument is extended to the ships too. LNG ships are specialised with cryogenic storage tanks. In comparison the NGH ships are simple in design with tanks having moderate thermal insulation and hence more flexibility. Thus ships can be built rapidly with an option at several shipyards around the world, thereby providing competitive prices as against the specialised LNG ships.

Chapter 5

Design and Technical Development of LNG storage from Safety aspects

A review of the developments in technology especially storage will be repetitive as the LNG technology is already proven and several projects have already been set up. However, a review related to the design and technical developments from safety aspects of LNG storage maybe worthwhile. This chapter will try to identify the areas related specifically to the developments in LNG storage safety and which can be analysed by risk assessment.

The LNG storage designs as described by Jones D.A - A review of the Developments in LNG storage: Safety as reflected by risk assessment, can be broadly divided into 5 concepts due to the characteristic features of each main construction feature of the storage tank. The objective of this chapter is to amplify the developments in LNG storage associated with shipping import or export terminals and where the value for describing the safety of inland peak-shaving terminal is limited.

5.1 Basic storage development:

There have been 2 major influences leading to the developments in the LNG storage design, one, which is technological and second, is the regulatory system. The technological influence is related to the developments in material specifications and selection especially when decisions on materials for larger storage capacities are to be considered. However, the design is more directly influenced by changes in legal codes and regulatory controls.

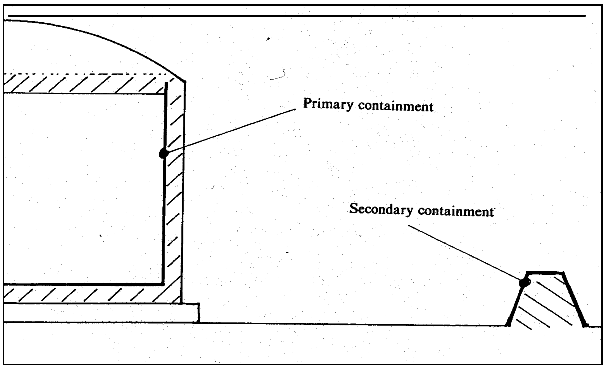
The initial development of the LNG storage system was adapted from the Liquid oxygen (LOX) storage tank design, which involved using concrete as an alternative construction material. The LNG industry has expanded during the last 20 years and although the techniques may differ in detailed design and construction the basic construction features can explain them. The following 5 concepts are based on the description of the primary containment system which is in direct contact with LNG and the secondary system which holds the LNG that escapes from the primary containment system. As recommended by The British Standard Institute 7777 the tanks should be designed to suit internal positive pressures not greater than 140mbar gauge (1mbar $=10^{-3}$bar $=100n/m^2$) and the internal negative pressure not greater than 6mbar. The tanks are generally cylindrical or spherical with a low aspect ratio (height to width) and a domed roof. Storage pressures are very low, less than 5psig. The gas is stored at “boiling cryogen” i.e. it is a very cold liquid at its boiling point. The stored LNG is analogous to boiling water which would mean that the temperatures of boiling water do not change, even with increased heat, as it is cooled by evaporation (steam generation). Similarly LNG will stay at near constant pressure and temperature. This phenomenon is called “autorefrigeration” and as long as the LNG vapours boil off is allowed to leave the tank the temperature will remain constant. All caution must be taken to draw off the vapour, as otherwise there can be an increase of temperature and pressure.

5.2 Design concepts*(Source: British Standard Institute 7777, Tokyo Gas: Sodegaura LNG terminal, Jones D.A – A Review of the Development in LNG Storage: Safety as reflected by Risk Assessment)*

5.2.1 **Concept 1:**

The storage tank is made up of a single wall of material that can withstand cryogenic conditions and is insulated. It is held by another tank wall, which is non cryogenic. The cryogenic material suitable is aluminium or 9 % nickel steel within carbon steel insulation. An improved aluminium alloy 5038-8 is often used and a centre line bulkhead is added to each tank. The inner tank is designed to maintain the low temperature and ductility requirements for the storage of the product. The outer wall is primarily for the retention and protection of insulation and to constrain the vapour purge gas pressure, but is not designed to contain refrigerated liquid in the event of leakage from the inner tank. It is similar to oil storage where the secondary containment is in the form of a low carbon bund or dyke around the tank.

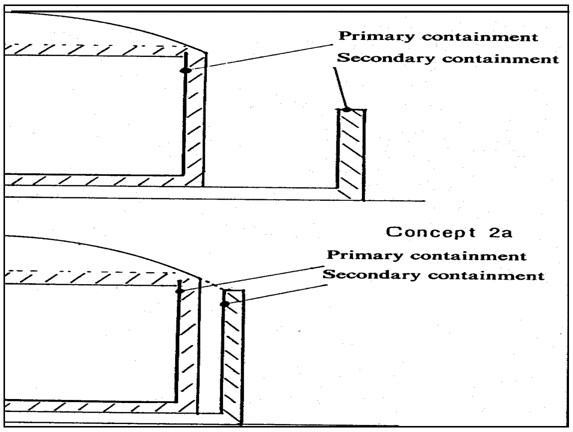
Concept 1



Source: Review of the development in LNG storage: Safety as reflected by Risk Assessment
Fig. 5.1 Concept 1

5.2.2 Concept 2:

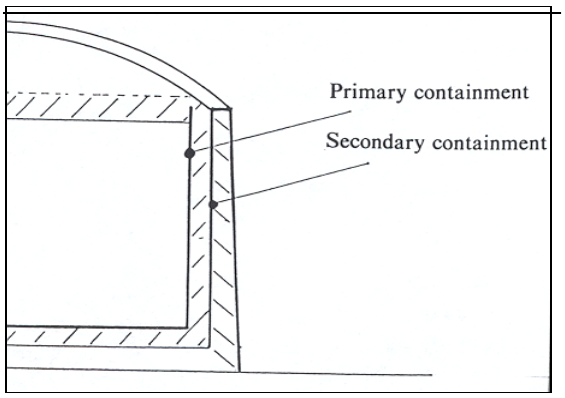
In this concept the secondary containment system is of a 'high close to the tank wall' design. The space between the inner and outer tank is kept inert with nitrogen gas as insulation. The effect of this insulation is to minimise heat gain to the tank, and maintain the outer tank at approximately ambient temperatures as well as minimise condensation or ice formation. The system should incorporate a vapour barrier and be fire resistant. The tank materials are constructed of waffled or corrugated plates in such a way that each plate is free to contract or expand independently of the adjacent plate. The height and distance is determined by the volumetric capacity within the bund and any regulatory requirements. However, it is found that this design is very expensive to build with high operating costs.



Source: R*eview of the development in LNG storage: Safety as reflected by Risk Assessment*
Fig. 5.2 Concept 2

5.2.3 Concept 3:

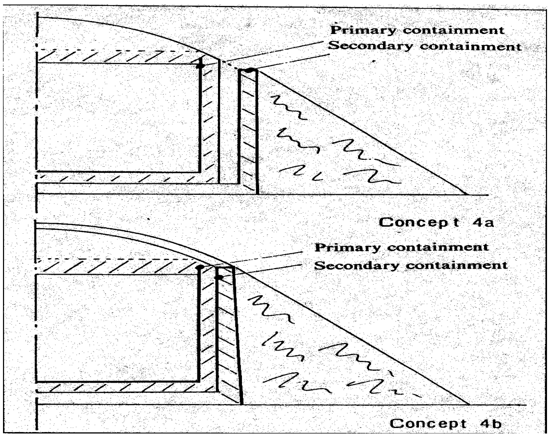
In this concept both the primary and secondary containment system are made of cryogenic material. Generally the design consists of 2 tanks with insulation between them and a common roof.



Source: R*eview of the development in LNG storage: Safety as reflected by Risk Assessment*
Fig. 5. 3 Concept 3

5.2.4 Concept 4:

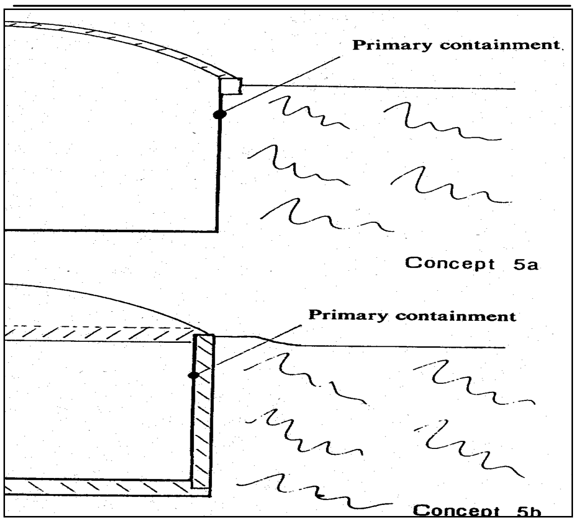
In this concept the secondary containment system maybe designed similar to concept 2 or 3 but is additionally strengthened mechanically by using earthen berm. Further, the tank sphere is welded to a cylindrical skirt. The sphere can thus expand and contract freely since all the movements are compensated for in the top half of the skirt. Insulation consists of polyurethane foam to control thermal stresses and heat leakage. The element analysis of tank structures and studies of the fracture mechanics of the cryogenic metals used in the tank construction resulted in this tank design where "leak before failure" characteristic is the primary feature. Should a crack occur in the tank, the leakage will be detected by sensors long before the crack could reach critical proportion, allowing repairs to be effected in sufficient time. The system also utilises a small leak-protection system external to the tank, consisting of a drip tray under the tank along with splash shields at the sides to catch leaks.



Source: Review of the development in LNG storage: Safety as reflected by Risk Assessment
Fig. 5.4: Concept 4

5.2.5 Concept 5:

In this concept the system is underground. It does not utilise the distinct primary or secondary containment system. The trend is to construct an inner liner to maintain favourable operating conditions. The ground tanks normally consist of a thin stainless membrane, surrounded by insulation and a shell of reinforced concrete. The effect of insulation is to minimise heat gain to the tank and maintain the outer tank at approximately ambient temperatures, minimising condensation and ice formation. The design of the insulator may allow for the contraction or expansion of the inner tank. The system should incorporate a vapour barrier and be fire resistant. In general, the ground tanks are more difficult and expensive to build but have an advantage, as larger amounts of the gas can be stored in ground and so no protective dyke is necessary. Continuous developments are in progress to try and improve safety and reliability as well as shorten the required construction period. The tanks can be placed closer together, resulting in significant savings in land cost, as well as to avoid the possibility of LNG spilling at the ground level. *(Source: Tokyo gas Ltd Construction: Technology of LNG Inground tank: Application of Civil work robots, large sized prefabricated roof and other advanced construction technology to the world's largest LNG inground tank)*



Source: R*eview of the development in LNG storage: Safety as reflected by Risk Assessment*

Fig. 5.5: Concept 5

It has been found that concept 4 and 5 are relatively safer concepts. However whilst recognising "safety should be a real concern", the reduction of the cost of "investment, operation and maintenance" is also necessary. Operators and investors obviously would be looking for technological developments, which are cost effective.

5.3 Concepts that govern safe cargo transportation and handling arrangement:

As most procedures involve transporting and handling at low temperatures or refrigeration, it is important that at no time must air be permitted to enter the tanks and piping, except in the event of an inspection. Thus it maybe said that the cargo is handled in a close system under a slight positive pressure to prevent air from entering the system. Also the cargo vapour should not be vented to the atmosphere either at sea or alongside the port. All proper arrangements should be made for the low temperatures involved both as regards selection of materials and allowances for expansion or contraction.

Access for personnel and all pipe connection and fittings maybe preferred via domes at the top of each tank. The domes could be fitted with flexible gas/weather tight skirts to prevent the escape of inert gas or dry air, which fills the spaces around the tanks; and also allows independent tanks to expand and contract thereby increasing safety.

The cargo “boil off ”, which is the natural vaporisation due to the heat leak through the insulation and tank support system is transmitted by the compressors, via a heater to the boilers. Here it is burnt in combination with the conventional oil fuel. An automatic combustion control system ensures that all the gas is burnt, and the oil fuel is used as ‘make up’ as needed.

In the case of ships, at many discharge terminals, notably the USA and Japan, the port authority will not permit gas to be vented to atmosphere within port limits. This means that when proceeding at slow speed and/or manoeuvring at which time fuel demand is low, an alternative method of using the boil off must be used. Some of the adopted methods of using the boil off is using an oversize container or ‘catalytic’ combustion system or heat the boil off to ensure it is lighter than air and mix it with nitrogen to ensure that the effluent is non-inflammable. Special precautions are required to ensure that the gas piping into the machinery space is 100% leak proof. This can be obtained by fitting a continuously ventilated ducting around the gas line from shore to the storage tank with a built-in gas detection system and with auto shut off and purging mechanism in the event of a gas leakage.

The cargo handling and transportation of LNG as a whole is simpler as compared to other refrigerated cargo e.g. LPG, although temperatures are much lower and therefore expansion/contraction on the system is greater. This requires more care to avoid thermal gradients during cool down and warm up operations.

The cargo during the entire transportation is of a single grade type. There are no problems associated with back hauling of one cargo incompatible with its predecessor or 2 incompatible products being discharged simultaneously. Furthermore, small leaks from the piping system produce lighter than air non-toxic vapour as compared to the heavier air LPG or toxic NH_3 gases. At the same time the gas being cooler, any inadvertent spillage can result in local cracking. However it can be concluded that proper care, attention and strict adherence especially to the manual (which is mandatory) must be exercised at all times. *(Source BS 7777: Guidance on detailed design criteria with relevant limit considerations for design analysis to ensure adequate degree of safety BS 8110: Part 1 & 2.)*

5.4 Materials selection for the storage tanks: The material selection for the tanks should be able to withstand the low temperatures as is found in carbon – manganese or low nickel steel at temperatures less than 0^oC. However it should consider some of the environmental safety considerations associated with large low and cryogenic temperature storage installations. Another factor to be considered in material selection is the degradation effect of welding. One of the methods is to specify quality control Charpy V- notch impact test requirements for base material subject to welding, which in conjunction with the design inspection and cooling requirements could meet the provisions. The tensile testing of 9 % nickel weld metal could be used. *(Source: British Standard International 7777 Flat bottomed, vertical, cylindrical storage tanks for low temperature service, BSEN 10045, BSEN 10045-1:1990 Charpy impact test on metallic materials. Test method v-s U-notches)*

5.5 Foundations: The foundation of the storage tanks is important especially where it involves reclamation of land. This should support design loading and ensure structural integrity. Due to the wide variety of soil, surface, subsurface, climatic conditions, storage concept, the soil loading and foundation system may vary with every individual case. However, as stated in the British Standard International 7777: Recommendations for design and construction of pre stressed and reinforced concrete tanks and tank foundation, the design of the foundation should take into account the following aspects:

- "imposed loads which represent a major proposition of the total gravity load.

- imposed loads are frequently fully attained, but can also vary frequently as the contained liquid level is changed.
- the contents of a liquefied gas storage system represent a high concentration of energy where accidental release could have severe consequences.
- the low temperatures of the tank contents could cause problems of ground freezing and frost heave for certain types of soil or rock and protective measures maybe undertaken in the foundation system".

5.6 Site selection: Where economic considerations allow alternate areas the following sites maybe avoided:

i. Those sites where a part of the tank is on firm ground or rock whilst part is on reclaimed land even though it has been pre-consolidated.

ii. Sites on swamps or where there is compressible material below the surface (especially silt material which is being used to reclaim land in some of the West Coast ports).

iii. Sites where stability of the ground is not confirmed. This maybe so in areas adjacent to deep-water courses, mining operations, excavation or steeply sloping hill sides or gypsiferous materials.

iv. Those sites which maybe prone to floods or lowering of the ground water tables resulting in different settlements.

(Source: Reference of specification of accordance BS 8804: 1986)

The design of the tank base and the foundation of the containment system should be of suitable load bearing strata. It should be impermeable to the stored product in the event of leakage and able to withstand the anticipated differential and total settlement. For the differential settlement limits the following table maybe used for guidance:

Table 5.1 Differential Settlement Limits

Type of settlement	Differential settlement limit
Tilt of tank	1:500
Tank floor settlement along a radial line from the periphery to the tank centre	1:300
Settlement around the periphery of the tank	1:500

Source: British Standard 7777

Although most of the settlement is generally before commissioning, it is necessary to ensure that connection to adjacent plant, pipeline etc. will accept any residual, relative settlement. Settlements should be monitored during the various phases of installation, construction, hydrostatic testing, commissioning and operation.

5.7 Jetty: The jetty maybe built of T- headed steel pipe piles 12m apart supporting two 45 cm stainless steel pipelines through which LNG is pumped. The pipelines need to be insulated preferably 15cm thick layer of polyurethane, with bellows at intervals to allow for contraction. Further, it is important to keep the pipelines cold between loading and unloading operations by circulating LNG out through one line and back through the other to the storage tank.

Mooring of the ship is done with the bow pointing out to sea with a gap of 27m between the stern and the terminal for safety purposes. The line at the bow are connected to buoys (generally 3) whilst stern lines to 4 dolphins at the terminal end. Chiksan arms (approximately 140cm diameter) connect the ship's cargo manifold and a 40cm vapour return arm. Vapour formed during loading, unloading and cool down can be taken to a flare stack a safe distance from the terminal.

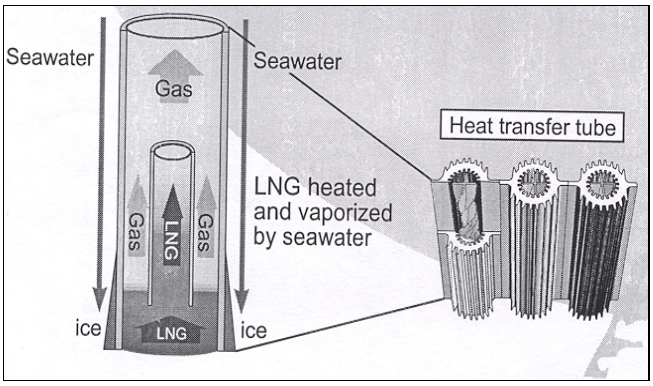
5.7.1 Unloading arms: Double ball valves for the Powered Emergency Release (PERC) increases safety while unloading LNG. They prevent damages to the arms and large quantity leaks of LNG, by uncoupling the unloading arm from the LNG tanker, in the case of an unexpected shift of the tanker.

Regasification is done partly by heat exchangers with seawater and partly by gas burning combustion evaporators. During regasification, substantial cold maybe produced which has a high potential value for industrial purposes and all steps can be taken to utilise it for manufacturing nitrogen, oxygen and argon by air separation. *(Source: Tokyo Gas Ltd. In co-operation with Niigata Engineering Company Ltd: Reconstruction works at Sodegaura works berth no. 2)*

5.8 Technological developments to make LNG cost effective:

Following are the technological developments, which could make LNG more cost effective, stable and economical supply of gas

New LNG vaporiser: A compact and high – performance LNG vaporiser has been developed. This has tripled the capacity for vaporisation while reducing the installation space by more than 50% compared with convention ones.

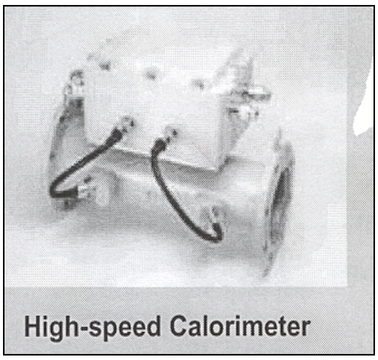


Source: Logicon Engineers Ltd
Fig. 5.6 Development in the vaporiser

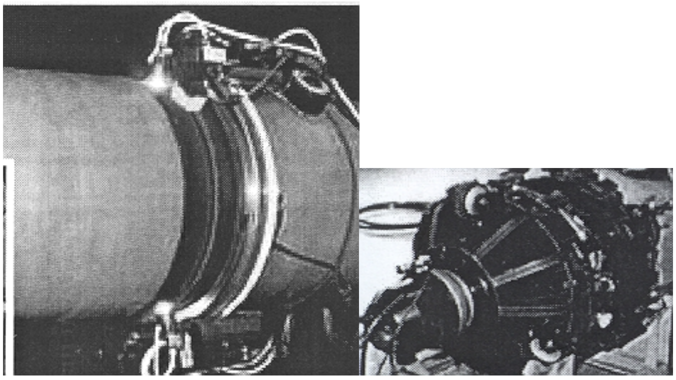
Reliquefaction and storage for Boil of gas: Cryogenic storage technology has been incorporated to develop a new system, which has reduced electricity consumption by 30 to 60%.

High speed calorimeter, quick- responding odorant meter: The new calorimeter has employed ultra-sonic sensors for high-speed and high performance measurement for gas quality. The new odorant meter has realised continuous, high -speed measurement of odorised gas by means of absorbing ultra-violet rays.

Fig 5.7 High Speed Calorimeter



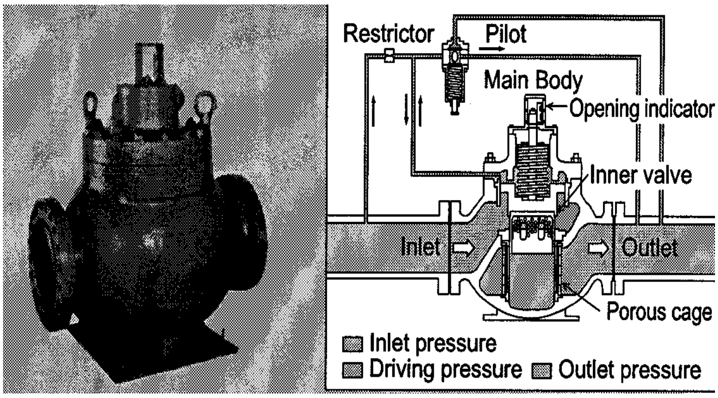
Development of Automatic Both-side welding device: A new type of welder has been developed in order to improve the efficiency of welding work. The welding time has been reduced from 110 minutes to 35 minutes.



Source: Logicon Engineers Ltd.

Fig. 5.8 Automatic welding device

Development of high-pressure regulator: A compact large capacity regulator has been developed in order to reduce and assist better maintenance.



Source: Logicon Engineers Ltd.

Fig. 5.9 High pressure regulator

To conclude developments in technology especially from the safety aspect and cost effectiveness are continuous. It is however, crucial that one adopts only those methods that are not a risk to the safety.

Chapter 6
Conclusion and Recommendation

From the preceding chapters it can be concluded that:

- There is a deficit of energy in India, and the government is targeting a total capacity of 113,500 MW by 2007 to meet this shortage. This will necessitate increasing dependence on the import of energy resources either aboard ships or pipelines. The optional fuel resources are coal, crude oil, natural gas, hydroelectric and nuclear power.

- The country relies for its power generation on coal for 55 % of its energy requirements and oil accounts for 31 % of the consumption. India's 9^{th} 5 year plan states that the country will run out of oil reserves by 2012. The increased coal consumption has led to a nine-fold increase in energy – related carbon emissions. It can thus be concluded that there is an urgent need to consider an alternate resource for the large power plants to meet the energy deficit and the environment concerns, hence natural gas is suggested as an option.

- World - wide scenario of LNG industry is facing pressures which will effect the energy industry. The Asian economic crisis intensified for structural changes in LNG, as well as unlocking new markets like China, India and Korea.

- There is an oversupply of LNG in the market thereby lowering the LNG prices. This can therefore be seen as an advantage for new projects as pricing is an important determining factor. It will assist in making LNG competitive as compared to the other fuels.

- Natural gas is a desirable energy source, which burns cleanly, environment friendly with little pollution, although expensive to produce and transport as compared to coal and oil.

- Comparison studies of LNG economies with other fuel sources namely coal and oil on a cost basis may not always place LNG on an upper edge. A critical factor would be to try and reduce capital costs to make it viable.

- The LNG pricing mechanism is related to crude oil prices although from 1987 – 1991 pricing was political as producers tried to increase their export prices to oil prices on a thermal equivalent. However from a coefficient regression study it can be concluded that LNG and crude oil prices are positively co related with an r = 0 .81. Also investors are generally concerned with the expected payoff and the risks in the project. The risk management analyses show a co efficient variation of 0.04 which is low and hence low risk project.

- The high cost of LNG technology is a major concern. Thus continuous efforts to achieve cost reduction without sacrificing on safety is vital. From the studies conducted it maybe concluded that it is technically and economically feasible to transport the natural gas in the form of a frozen hydrate. Besides the capital cost difference is 26 % which is substantial. Furthermore, the technology appears less complicated, as it does not require specialised ships and is safer (transportation temps. of - 15^{o}C).

- For LNG to gain market share, the crude oil prices should be about \$ 20 per barrel and coal prices approximately \$ 40 per ton. Gas costs may fall and the market for premium based clean fuel may expand.

- LNG transportation and handling is a complex chain involving supplier, facilitator and consumer in a long term agreement (20-25 years) and calls for the construction of the supporting infrastructure and distribution network in new markets and the implementation of corporate strategies that affect production. Developers seek long term contracts and a price, which covers capital cost and includes "take or pay" and floor price agreement.

- To conclude the investments in LNG projects are so high and the cost of failure of any one of the links in the chain is so great, that any major departure from principles and practise is impossible to conceive.

Recommendations:

- It is recommended to consider Gulf as the supplier (R/P ratio, distances). Prices to be borne during negotiation could be in the range of $3.3 to $ 2.10 based on the probability of 55 % as an increase of crude oil prices. However, it is suggested that although historically crude oil is used as pricing mechanism the gas price can be determined independently in the future. Furthermore, the advantages of natural gas as a clean fuel must be highlighted to ascertain it as a premium fuel with a premium price. An awareness of the advantages amongst the public is vital, as it will elevate the willingness of them as consumers to pay the price.

- When entering contracts, negotiations should try and accomplish purchase of LNG on f.o.b. as against the traditional c.i.f. basis to increase flexibility and provide the buyer the freedom to pick up spot cargoes as and when required. Further, a change is expected in the trading pattern, as spot trading is presently not much favoured because of the fluctuation in prices. However, once charterers have worked out a more stable spot trading mechanism the method will be more practised. Presently companies like Duke, CMS and Enron have already introduced contracts that allow them to change the destinations on the bill of lading. As Indian companies are in the process of negotiating contracts it is recommended that this aspect should be considered.

- Although the transportation mode of natural gas as a frozen hydrate has never implemented till date, it is suggested that the development of Ice- in -Gas method is closely monitored. A pilot voyage can be carried out to develop confidence. As discussion on the contract is in progress in India, this stage is a crucial phase to also try, convince and demonstrate the new method.

- A clear policy should be developed, as there have been no imports of natural gas in the country. It is recommended that the policy includes fiscal reforms at the centre and states, lowering tariffs to Asian levels, increasing approvals for foreign investments, cost based pricing in infrastructure and a legal reform.

- To attract venture capital, the Indian government should include infrastructure and energy sector on the tax break up offers. The Infrastructure Development Finance Corporation (IDFC) could improve credit to infrastructure projects such as power plants, gas import terminals by extending long term loans and guarantees that existing institutions do not provide. Thus project financing which is a critical factor since these projects are very capital intensive could be enhanced. The Reserve Bank of India (RBI), could consider easing the rules for infrastructures by banks, which can now issue guarantees to loans provided by other lending institutions if they fund part of the project. Although under discussion, RBI has not raised the exposure limit of banks to infrastructure projects in roads, power, telecommunication and ports from 50 to 60 % of capital funds. It is suggested that this is implemented at the earliest as the country is in a stage of discussion with energy suppliers.

- As land is often a constraint with most of the ports on the West Coast having to reclaim land, concept 5 (underground storage tanks) is advisable.

- Technology on the landside for import terminal is more or less mature, however improvements especially from safety prospective are preferred. Developments in vaporiser, high-speed calorimeter can help reduce costs further.

- The study is an attempt to understand the impact of technological development on the economic feasibility of the LNG chain with respect to developing an import terminal in India. The technological know how, innovations and continuous improvements along with cost advantageous developments will help in making LNG a competitive fuel. However joint efforts of the designers, technology, commercial, supplier and consumer etc. are a definite prerequisite to minimise long term costs and to meet the requirements of the present and the future Indian energy markets.

Bibliography

Awaiting the impact of higher LPG prices, (1995, February) Lloyd's Shipping Economist.

B.C gas industry. Learn about natural gas. http: // www.bcgas.co/html/about-util-learn.html (3/28/99).

Bainbridge, K and Salles, R. (March 2,2000). Shipping is LNG showstopper. Fairplay. p. 14.

Bhattacharya A.A, & Gupta, S.P. (1998). Deregulation in energy sector: Indian experience and perspective.

BP Amoco Statistical Review of world energy June 1998. London.

BP Amoco Statistical Review of world energy June 1999. London.

BSI 7777. (1993). Flat bottomed, vertical, cylindrical storage tanks for low temperature service. Part 1. British standard: London.

BSI 7777. (1993). Recommendation for the design and construction of pre stressed and reinforced concrete tanks and tank foundations and for the design and installation of tank insulation, tank liners and tank coatings. Part 3. British Standard: London.

BSI 7777. (1993). Specification for the design and construction of single, double and full containment tanks for the storage of liquefied gas at temperatures down to -165°C. Part 2. British Standard: London.

Charlotte, L. (February 25, 1999). Ice with implications. Fairplay: UK.

Chaudhry.R (1999). Energy security policy for India. The case of Oil and Natural Gas.

Corhill M. LNG traders; New terminals boast for Atlantic.

Corkhill, M. (November 24,1999). LNG carriers; Feedback on the gas after brief spell in low gear. BIMCO Weekly News no. 47 p. 9.UK: BIMCO Book Production Consultants.

Dubar, C. Forcey, T. and Humpreys, V. Offshore – 1997, Major advantages to set up LNG plants offshore.58 (8), 116.
Energy Information Administration (EIA): Office of Energy Markets and End Use, International Statistics Database. International Energy Outlook (Washington DC, Feb 1998).

Fairplay (1996, January). "Growing LNG demand threatens imbalance". Fairplay, p.50.

Fairplay (1998,November). Gas carrier design. Fairplay. p.15.

Fairplay (December 1999). Spot market will highlight LNG carrier shortage. Fairplay, p.55.

Fairplay (February 1999a). Science outstrips LNG investments. Fairplay. p.22-23.

Fairplay (February 199b). Ice with implications. Faiplay, p. 24.

Fairplay (February, 1999d). New ways to keep cool. Fairpla*y*, p.46.

Fairplay, (1999). LNG: India's new mantra. Fairplay Oct 7, 1999.

Fairplay, (February 17, 2000). Trading logic threatens LNG. Fairplay. p. 59.

Ffooks R, (1984): Gas Carriers. London: A Fairplay Publication.

Ffooks, R. (1993). Natural Gas by sea: The development of a new technology. London: Witherby.

Global patterns and prospects. London: Drewry Shipping Limited.

Government of India, Economic survey 1996-1997 (1997). New Delhi, Akaland publications.

Harper, C.M.(1994). Gas Tech Conference. Quantitative risk analysis for the selection of cost effective measures to improve LNG production availability. Gas tech conference: 25-28 October 1994, Kuala Lumpur – Malaysia.

Hawkshaw, H.J.& Flower, A.R. (1995). Gas Tech Conference 1996. Will new LNG supplies be developed to meet Asian LNG demand to 2015.11th International Conference on Liquefied Natural Gas.3-6 July, Birmingham.

Hisazumi, Y.and Yamasaki, Y. (1995). Gas Tech Conference. Natural Gas reliquefication, storage, sendout system, using mixed alcohol as refrigerant. 11th International Conference on LNG. 3-6 July 1995, Birmingham.

Indian Economic Survey 1999 – 2000. March 2000. New Delhi. Akaland publications

International Chamber of Shipping, Tanker Safety Guide (Liquefied Gas). London.
International Energy Outlook 1999. World Energy consumption. Washington D.C.

Jamri report. (June 1988). World's LNG situation and LNG carriers. Japan Maritime Research Institute: Japan.

Jan Gudmundsson,(1999). Science outstrips LNG investment: Gas hydrates to revolutionise energy market. Fairplay Feb 25, 1999 p. 22.

Jeff Beale (January 4, 2000). Non – Traditional Sources and uses of LNG. CH-IV LNG Company http://www.ch-ivcom/lng

Joglekar S. (1999). Gujarat told to compete feasibility study for gas grid projects. The Financial Express. Mumbai: Benett Coleman.

Joyce, T.J. (1986). Gases as transportation fuels Section 8, Gas Tech Conference, Hamburg Germany.

Lloyd's list (January/February 2000). Owners target LNG market as demand for ship soars. Lloyd's list Maritime Asia.

Lloyd's list (June 17, 2000). Players line up as India moves to import LNG..

Lloyd's list (October 14,1999) LNG trades/2.Dabhol leads Indian breakthrough:

Lloyd's list (October14, 1999) LNG trade /2. Middle East role growing.

Lloyd's Shipping Economist, (February 1999). New capacity in the pipeline. Lloyds Shipping Economist. Feb 1999, p. 30-32.

Lloyds (1995, August) "Asian LNG demand exceed to supply by 2000", Lloyd's Shipping Economist.

Lloyds (1996, March) "Asian / Indian demand offsets fleet growth fears"). Lloyd's Shipping Economist. P.21-22.

LNG journal (1999). Progress in India. LNG journal. p. 4-5.

LNG market statistics: LNG Express. http:// www.lng express.com/stats.htm

Mark, E.P. (1973). LNG and world energy resources. Kingspoint New York.

MoF (1998). Economic Survey (1998/1999) New Delhi; Ministry of Finance. Government of India.

MoF (1999). Economic Survey (1998/1999) New Delhi; Ministry of Finance. Government of India.

MoP (1999). Annual report 1998/1999. New Delhi; Ministry of Power, Government of India.

Navaz, M.Z. An approach towards establishing a safety survey of a liquefied gas terminal, Lloyd's register of shipping, London.

Ocean shipping consultants (1991). Gas carriers: Market prospects in the 1990s. Surrey: London.

Ocean Shipping Consultants, (1992). LNG and LPG carriers: Demand and supply prospects to 2005. U.K: Ocean Shipping Consultants Ltd.

Oil and Natural Gas journal (December 8, 1996) India calls for LNG, Alexander's Gas and Oil Connection: News and trends.

Oil Companies International Marine Forum (OCIMF).(1982).Safety Guide for Terminals Handling Ships Carrying Liquefied Gas in bulk. London: Witherby.

Quantified Risk Assessment: Its inputs to decision making. UK: Boston Spa Wetherby. West Yorkshire.

Robinson, E.R. (1980). A review of LPG cargo quantity calculations. Preparation for the Society of International Gas Tanker and Terminal Operations Ltd. London: Witherby.

Seaborne trade and transport (1992). Oil traders: Secondary transportation modes and tanker demands. Drewry publications: London.

Seaborne trade and transport reports (1995): Prospects for LNG and LPG shipping in the 1990s. London: Drewry Shipping Consultants.

Seaborne trade and transport reports, (1992): Trading in LNG and Natural Gas -
Shell Briefing Service (1983). Natural Gas. Shell Briefing Service. London: Shell International Petroleum Limited.

Shell Briefing Service (1989), Energy in Profile. Shell Briefing Service. London: Shell International Petroleum Limited.

Shell Briefing Service (1992) LNG. Shell Briefing Service. London: Shell International Petroleum Limited.

Shell Briefing Service (1995). Energy in profile. Shell Briefing Service. London: Shell International Petroleum Limited.

Shirazi, M.M. (1986). Natural gas in developing countries: The World Bank's Perspective. The World Bank, Gas tech conference. Nov 25-28, 1986. Hamburg, Germany.

Society of International Gas Tankers and Terminal Operators Limited (1997). Site selection and design for LNG ports. London: Wright Marine Technology.

Storage, Development and Operations http://www.storgas.com/natural.html.

The British Petroleum Company, (1996). BP Statistical Review of World Energy. London: Group media and publications.

The problems multiply in Asia. Petroleum Economist, September 22, 1998.

The tolerability of risk from nuclear power stations: Health and safety executive-London: UK.

Vik, I. Norsk Hydro: A pre – feasibility study on offshore production and loading of LNG at Tromsoflaket, Norway.

Voight, F.R. (1994). Gas Tech Conference.The world gas market: Challenges for 2000 and beyond. Gas tech conference. 25-28 October 1994, Kuala Lumpur-Malaysia.

World LNG trade and shipping (April 1976) An economic study No. 42 Shipping Consultants Ltd. H.P Drewry: London.

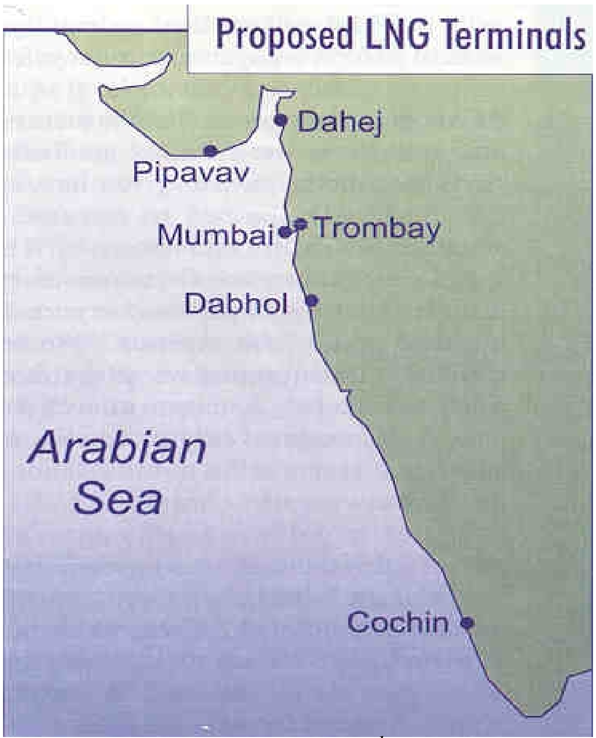
World trade in LNG (July 1976). An economic study No 17: Shipping Consultants Ltd. H.P Drewry: London.

WRI (1999): World Resources 1998/1999. New York: World Resources Institute.

APPENDIX

Appendix 1

Proposed LNG terminals on the West Coast of India



Source: Fairplay October 17th 1999.

Appendix 2

Cost per tonne to the power plants for different fuel sources:

Domestic coal

Domestic coal	Rs / tonne
Ex pit	375.0
Cess	3.5
CST	29.8
Transport from east to west coast	125.0
Total	**533.3** ***USD 12.4***

1USD = Rs 43 Source: Logicon Engineers India

Note: *Ex pit: At the coalmine and similar to Ex works. The coal deposits in India are concentrated in the eastern region. The setting up of a coal-fired power plant in the western region entails transportation of coal over a distance exceeding 1500 km.*

Imported coal

Imported coal	USD/ tonne
CIF	75.0
Customs duty	25.0
Port dues	2.5
Transport	1.5
Total	**104.0**

Source: Logicon Engineers India

Domestic naphtha

Domestic naphtha	Rs / tonne
Administered rate	5000.0
Excise	1000.0
Transport	125.0
Total	**6125** ***USD 142.44***

Source: Logicon Engineers India

Imported naphtha

Imported naphtha	USD / tonne
CIF	245
Customs duty	24
Port charges	2.2
Transport	2.9
Total	**274.1**

Source: Logicon Engineers India

Fuel oil

Fuel oil (Gulf)	USD / tonne
CIF	100
Customs duty	25
Transport	2.9
Total	**127.9**

Source: Logicon Engineers India

Appendix 3

Comparative prices of different fuel:

Oil:

US dollars per barrel

Year	Dubai $ /bbl*	Brent $/bbl**	Nigerian Forcados $bbl/d	West Texas Info. $bbl/d
1990	20.50	23.81	23.85	24.52
1991	16.56	20.05	20.11	21.54
1992	17.21	19.37	19.61	20.57
1993	14.90	17.07	17.41	18.45
1994	14.76	15.98	16.25	17.21
1995	16.09	17.18	17.26	18.42
1996	18.56	20.81	21.16	22.16
1997	18.13	19.30	19.33	20.61
1998	12.16	13.11	12.62	14.39

Source: Platts

Coal:

US dollars per tonne

Year	Marker price (Northwest Europe)	Price of US coal at electric plant	Japan coking coal import c.i.f. prices	Japan steam coal import c.i.f. price
1990	43.48	33.57	60.54	50.81
1991	42.81	33.10	60.45	50.30
1992	38.53	32.35	57.82	48.45
1993	33.68	31.51	55.26	45.71
1994	37.18	30.88	51.77	43.66
1995	44.50	29.78	54.47	47.58
1996	41.25	29.16	56.68	49.54
1997	38.92	28.83	55.51	45.53
1998	32.00	28.34	50.74	40.51

Source: Marker price – McCloskey Coal Information Service
BP Amoco Statistical Review of world energy 1999.

Appendix 4

Cost calculations of different fuel per kWh

	Consumption per kWh				
	Assumptions				
	BTU	**Kcal.**	**Tonnes**	**KWh**	
Fuel	3412	0.252		1	
LNG		1,000,000	1		
Oil		1,000,000	1		
Naphtha		7,000,000	1		1
Coal		860		1	
Calculations for different fuels					
Domestic coal / ton	Kcal equi.	kWh	USD/kWh	Cents/kWh	
1	7,000,000	8139.53	0.054	**5.36**	
Imported coal/ton					
1	7,000,000	8139.53	0.079	**7.91**	
Domestic naphtha/ton					
1	1,000,000	1162.79	0.156	**15.64**	
Imported naphtha					
1	1,000,000	1162.79	0.239	**23.91**	
Fuel oil					
1	1,000,000	1162.79	0.111	**11.05**	
LNG					
1BTU	0.252	293	0.1549	**15.5**	

Investment for Power generation using different fuel sources:

Power generation **Investment costs**

Particulars	Cost mm USD / kW
Coal fired	1,550
Oil fired	1,300
Combined cycle gas turbine	1,000
Combined cycle(imported naphtha)	1,200
Combined cycle (indigenous naphtha)	1,100

Source: Logicon Engineers India

Appendix 5

Capital cost break up for LNG and NGH chain

Table 5.A Capital Cost break up for a 4 billion Sm^3 LNG chain in 2 trains:

Plant unit	Million USD
Acid gas removal	33
Liquefaction	180
Utilities	130
Auxiliaries	70
Storage	114
Loading	55
Site preparation	35
Marine facilities	50
Recovery	100
Total direct cost	767
Indirect cost (35 %)	268
Total plant cost	1035
Contingency (15 %)	155
Total erected plant cost	1190

Source: Norwegian Institute of Technology, Aker Engineering Oslo.

Table 5.B Capital cost for a 4 billion S m^3 NGH plant in 4 trains:

Equipment	Million USD
1 x Separator (gas / liquid)	0.74
1 x Separator (gas / fuel gas)	0.74
6 x Gas splitters	0.88
4 x Hydrate reactors (1st stage)	5.88
4 x Hydrate reactors (2nd stage)	5.88
4 x Hydrate reactors (3rd stage)	5.88
8 x Pumps (between stages)	14.12
4 x Separators (hydrate fluids)	47.10
4 x Hydrate freezing	14.70
4 x Pumps (water for ice)	7.10
Process equipment	103.02

Source. J S Gudmundsson and F Hveding, Norwegian Institute of technology, Aker Engineering

Table 5.C Cost break up of NGH plant in 4 trains:

Particulars	Million USD
Process equipment	102.9
Auxiliary equipment	58.8
Ice making equipment	44.1
Power generation equipment	29.9
Bulk material and construction *	**352.9**
Marine facilities	51.5
Engineering and management (15 %)	95.6
Total	**735.2**
Contingency (30%)	220.6
Total plant cost	**955.8**
** (150 % of equipment cost)*	

Source. J S Gudmundsson and F Hveding, Norwegian Institute of technology, Aker Engineering

Appendix 6

Appendix 6 A

Coefficient corelation of LNG to Crude oil prices 1985 - 1990.

Year	LNG	Crude oil	XY	X^2	Y_1	$Y-Y_1$	$(Y-Y_1)^2$	$(Y_1-Y_i)^2$	$(Y-Y_i)^2$
	X	Y							
1985	5.23	4.75	24.84	27.35	4.467	0.283	0.080	1.361	2.103
1986	4.10	2.57	10.54	16.81	3.529	-0.959	0.921	0.053	0.533
1987	3.35	3.09	10.35	11.22	2.907	0.183	0.033	0.154	0.044
1988	3.34	2.56	8.55	11.16	2.899	-0.339	0.115	0.161	0.548
1989	3.28	3.01	9.87	10.76	2.849	0.161	0.026	0.203	0.084
1990	3.64	3.82	13.90	13.25	3.148	0.672	0.452	0.023	0.270
$\sum$	22.94	19.8	78.06	90.55			1.627	1.955	3.582

n	6
b	0.829
X_i	3.823
Y_i	3.300
a	0.129

a = $\boxed{\dfrac{\sum Y_s \sum X_s^2 - \sum X_s \sum X_s Y_s}{n\sum X_s^2 - (\sum X_s)^2}}$ b =   b = $\boxed{\dfrac{n\sum X_s Y_s - \sum X_s \sum Y_s}{n\sum X_s^2 - (\sum X_s)^2}}$

where Xs and Ys is the summation of X and Y.

The linear regression equation is as folloy   **a+bx**

Standard error of estimates = $\boxed{Syx = \sqrt{(\dfrac{\sum(Y - Y_1)^2}{n}}}$

Syx is the standard error of estimates of Y and X

where n = the number of intervals or intervals

$(Y\text{-}Y_1)^2$ is the difference between the actual Y value and the estimated Y_1 value.

Standard error estimate S_{yx} 0.520681

Correlation coefficient = r

The total variation of Y is $\sum(Y\text{-}Y_i)^2$

Y_i is the mean value of Crude oil prices

X_i is the mean value of LNG prices

r = $\boxed{\pm\sqrt{\sum(Y_1 - Y_i)^2 / \sum(Y - Y_i)^2}}$

r^2	0.546
r	0.74

APPENDIX 6 B
Co relation of LNG prices to Crude oil prices 1990 -1995

Year	LNG	Crude oil	XY	X^2	Y_1	$Y-Y_1$	$(Y-Y_1)^2$	$(Y_1-Y_i)^2$	$(Y-Y_i)^2$
	X	Y							
1990	3.64	3.82	13.90	13.25	3.206	0.614	0.377	0.005	0.47
1991	3.99	3.33	13.29	15.92	3.542	-0.212	0.045	0.165	0.04
1992	3.62	3.19	11.55	13.10	3.186	0.004	0.000	0.002	0.00
1993	3.52	2.82	9.93	12.39	3.090	-0.270	0.073	0.002	0.10
1994	3.18	2.70	8.59	10.11	2.763	-0.063	0.004	0.140	0.19
1995	3.46	2.96	10.24	11.97	3.032	-0.072	0.005	0.011	0.03
Σ	21.41	18.82	67.49	76.75			0.505	0.325	0.829

n	6
b	0.962
X_i	3.568
Y_i	3.137
a	-0.297

a = $\boxed{\dfrac{\sum Y_s \sum X_s^2 - \sum X_s \sum X_s Y_s}{n\sum X_s^2 - (\sum X_s)^2}}$ b = b = $\boxed{\dfrac{n\sum X_s Y_s - \sum X_s \sum Y_s}{n\sum X_s^2 - (\sum X_s)^2}}$

where Xs and Ys is the summation of X and Y.
The linear regression equation is as folly a+bx

Standard error of estimates = $\boxed{Syx = \sqrt{(\frac{\sum (Y - Y_1)^2}{n}}}$

Syx is the standard error of estimates of Y and X
where n the number of intervals or intervals
$(Y-Y_1)^2$ is the difference between the actual Y value and the estimated Y_1 value.

Standard error estimate S_{yx} **0.2901**
Correlation coefficient = r
The total variation of Y is $\Sigma(Y-Y_i)^2$
Y_i is the mean value of Crude oil prices
X_i is the mean value of LNG prices

r = $\boxed{\pm \sqrt{\sum (Y_1 - Y_i)^2 / \sum (Y - Y_i)^2}}$

r^2	**0.391**
r	**0.63**

Appendix 6

Table 6.C

Co efficient co relation of LNG to crude oil prices 1995 - 1999

Year	LNG	Crude oil	XY	X^2	Y_1	$Y-Y_1$	$(Y-Y_1)^2$	$(Y_1-Y_i)^2$	$(Y-Y_i)^2$
	X	Y							
1995	3.46	2.96	10.24	11.97	2.869	0.091	0.008	0.001	0.01
1996	3.66	3.54	12.96	13.40	3.179	0.361	0.130	0.112	0.48
1997	3.91	3.29	12.86	15.29	3.567	-0.277	0.077	0.523	0.20
1998	3.05	2.27	6.92	9.30	2.233	0.037	0.001	0.374	0.33
1999	3.14	2.16	6.78	9.86	2.372	-0.212	0.045	0.223	0.47
Σ	17.22	14.22	49.77	59.82			0.262	1.232	1.494

n	5
b	1.552
X_i	3.444
Y_i	2.844
a	-2.501

a = $\dfrac{\sum Y_s \sum X_s^2 - \sum X_s \sum X_s Y_s}{n\sum X_s^2 - (\sum X_s)^2}$ b = b = $\dfrac{n\sum X_s Y_s - \sum X_s \sum Y_s}{n\sum X_s^2 - (\sum X_s)^2}$

where Xs and Ys is the summation of X and Y.

The linear regression equation is as foy **a+bx**

Standard error of estimates = $Syx = \sqrt{(\dfrac{\sum (Y - Y_1)^2}{n}}$

Syx is the standard error of estimates of Y and X

where nthe number of intervals or intervals

$(Y-Y_1)^2$ is the difference between the actual Y value and the estimated Y_1 value.

Standard error estimate S_{yx} 0.228803

Correlation coefficient = r

The total variation of Y is $\Sigma(Y-Y_i)^2$

Y_i is the mean value of Crude oil prices

X_i is the mean value of LNG prices

r = $\pm\sqrt{\sum (Y_1 - Y_i)^2 / \sum (Y - Y_i)^2}$

r^2	0.825
r	0.91

APPENDIX 7

APPENDIX 7 A

Elasticity for LNG prices / Crude oil - 1 year

Year	LNG	Crude oil	XY	X^2	Y_1	$Y-Y_1$	$(Y-Y_1)^2$	$(Y_1-Y_i)^2$	$(Y-Y_i)^2$
	X	Y							
1990	3.99	3.82	15.24	15.92	3.575	0.245	0.060	0.22	0.52
1991	3.62	3.33	12.05	13.10	3.216	0.114	0.013	0.01	0.05
1992	3.52	3.19	11.23	12.39	3.118	0.072	0.005	0.00	0.01
1993	3.18	2.82	8.97	10.11	2.788	0.032	0.001	0.10	0.08
1994	3.46	2.7	9.34	11.97	3.060	-0.360	0.130	0.00	0.16
1995	3.66	2.96	10.83	13.40	3.254	-0.294	0.087	0.02	0.02
1996	3.91	3.54	13.84	15.29	3.497	0.043	0.002	0.16	0.19
1997	3.05	3.29	10.03	9.30	2.662	0.628	0.394	0.19	0.04
1998	3.14	2.27	7.13	9.86	2.749	-0.479	0.230	0.12	0.69
							0.000		
$\sum$	**31.53**	**27.92**	**98.67**	**111.34**			**0.922**	**0.834**	**1.756**

n	9
b	0.971
X_i	3.503
Y_i	3.102
a	-0.300

a = $\frac{\sum Y_s \sum X_s^2 - \sum X_s \sum X_s Y_s}{n\sum X_s^2 - (\sum X_s)^2}$ b = b = $\frac{n\sum X_s Y_s - \sum X_s \sum Y_s}{n\sum X_s^2 - (\sum X_s)^2}$

where Xs and Ys is the summation of X and Y.

The linear regression equation is as folloy **a+bx**

Standard error of estimates = $Syx = \sqrt{(\frac{\sum (Y - Y_1)^2}{n}}$

Syx is the standard error of estimates of Y and X

where n = the number of intervals or intervals

$(Y-Y_1)^2$ is the difference between the actual Y value and the estimated Y_1 value.

r2	**0.475**
r	**0.69**

APPENDIX 7 B

Elasticity for LNG prices / Crude oil - 2 years

Elasticity 2 year

Year	LNG	Crude oil	XY	X^2	Y_1	$Y-Y_1$	$(Y-Y_1)^2$	$(Y_1-Y_i)^2$	$(Y-Y_i)^2$
	X	Y							
1990	3.62	3.82	13.83	13.10	3.130	0.690	0.476	0.01	0.38
1991	3.52	3.33	11.72	12.39	3.173	0.157	0.025	0.001	0.02
1992	3.18	3.19	10.14	10.11	3.319	-0.129	0.017	0.01	0.00
1993	3.46	2.82	9.76	11.97	3.199	-0.379	0.143	0.000	0.15
1994	3.66	2.7	9.88	13.40	3.113	-0.413	0.170	0.01	0.26
1995	3.91	2.96	11.57	15.29	3.005	-0.045	0.002	0.04	0.06
1996	3.05	3.54	10.80	9.30	3.375	0.165	0.027	0.03	0.11
1997	3.14	3.29	10.33	9.86	3.336	-0.046	0.002	0.02	0.01
$\sum$	27.54	25.65	88.03	95.42			0.863	0.1141	0.977

n	8
b	-0.430
X_i	3.443
Y_i	3.206
a	4.685

a = $\boxed{\dfrac{\sum Y_s \sum X_s^2 - \sum X_s \sum X_s Y_s}{n\sum X_s^2 - (\sum X_s)^2}}$ b = b = $\boxed{\dfrac{n\sum X_s Y_s - \sum X_s \sum Y_s}{n\sum X_s^2 - (\sum X_s)^2}}$

where Xs and Ys is the summation of X and Y.

The linear regression equation is as fo y a+bx

Standard error of estimates = $\boxed{Syx = \sqrt{(\dfrac{\sum (Y - Y_1)^2}{n}}}$

Syx is the standard error of estimates of Y and X

where n the number of intervals or intervals

$(Y-Y_1)^2$ is the difference between the actual Y value and the estimated Y_1 value.

Standard error estimate S_{yx} 0.328392

r2	0.12
r	0.34

APPENDIX 7 C

Elasticity for LNG pricing 85 - 99 3 years

Year	Crude	LNG	XY	X^2	Y_1	$Y-Y_1$	$(Y-Y_1)^2$	$(Y_1-Y_i)^2$	$(Y-Y_i)^2$
	X	Y							
1985	4.75	3.34	15.87	22.56	3.199	0.141	0.020	0.081	0.020
1986	2.57	3.28	8.43	6.60	3.597	-0.317	0.100	0.013	0.041
1987	3.09	3.64	11.25	9.55	3.502	0.138	0.019	0.000	0.025
1988	2.56	3.99	10.21	6.55	3.598	0.392	0.153	0.013	0.258
1989	3.01	3.62	10.90	9.06	3.516	0.104	0.011	0.001	0.019
1990	3.82	3.52	13.45	14.59	3.368	0.152	0.023	0.013	0.001
1991	3.33	3.18	10.59	11.09	3.458	-0.278	0.077	0.001	0.092
1992	3.19	3.46	11.04	10.18	3.483	-0.023	0.001	0.000	0.001
1993	2.82	3.66	10.32	7.95	3.551	0.109	0.012	0.005	0.032
1994	2.70	3.91	10.56	7.29	3.573	0.337	0.114	0.008	0.183
1995	2.96	3.05	9.03	8.76	3.525	-0.475	0.226	0.002	0.187
1996	3.54	3.14	11.12	12.53	3.420	-0.280	0.078	0.004	0.117
Σ	38.34	41.79	132.75	126.72			0.834	0.141	0.975

n	12
b	-0.183
X_i	3.195
Y_i	3.483
a	4.066

a = $\boxed{\dfrac{\sum Y_s \sum X_s^2 - \sum X_s \sum X_s Y_s}{n\sum X_s^2 - (\sum X_s)^2}}$ b = b = $\boxed{\dfrac{n\sum X_s Y_s - \sum X_s \sum Y_s}{n\sum X_s^2 - (\sum X_s)^2}}$

where Xs and Ys is the summation of X and Y.

The linear regression equation is as foy **a+bx**

Standard error of estimates = $\boxed{Syx = \sqrt{(\dfrac{\sum (Y - Y_1)^2}{n}}}$

Syx is the standard error of estimates of Y and X

where n the number of intervals or intervals

$(Y-Y_1)^2$ is the difference between the actual Y value and the estimated Y_1 value.

Standard error estimate S_{yx} 0.263608

r2	**0.14**
r	**0.38**

APPENDIX 7D

Co relation of GDP to Crude Oil 90 - 99

LNG prices / Crude oil

Year	GDP	Crude oil	XY	X^2	Y_1	$Y-Y_1$	$(Y-Y_1)^2$	$(Y_1-Y_i)^2$	$(Y-Y_i)^2$
	X	Y							
1995	7.4	2.96	21.90	54.76	3.145	-0.185	0.034	0.09	0.01
1996	7.4	3.54	26.20	54.76	3.145	0.395	0.156	0.09	0.48
1997	5.1	3.29	16.78	26.01	2.612	0.678	0.459	0.05	0.20
1998	4.6	2.27	10.44	21.16	2.496	-0.226	0.051	0.12	0.33
1999	6.0	2.16	12.96	36.00	2.821	-0.661	0.437	0.00	0.47
Σ	30.5	14.22	88.28	192.69			1.137	0.357	1.494

n	5
b	0.232
X_i	6.100
Y_i	2.844
a	1.430

a = $\boxed{\dfrac{\sum Y_s \sum X_s^2 - \sum X_s \sum X_s Y_s}{n\sum X_s^2 - (\sum X_s)^2}}$ b = b = $\boxed{\dfrac{n\sum X_s Y_s - \sum X_s \sum Y_s}{n\sum X_s^2 - (\sum X_s)^2}}$

where Xs and Ys is the summation of X and Y.

The linear regression equation is as follow **a+bx**

Standard error of estimates = $\boxed{Syx = \sqrt{(\dfrac{\sum (Y - Y_1)^2}{n}}}$

Syx is the standard error of estimates of Y and X

where n = the number of intervals or intervals

$(Y-Y_1)^2$ is the difference between the actual Y value and the estimated Y_1 value.

Standard error estimate S_{yx} **0.476952**

Correlation coefficient = r

The total variation of Y is $\Sigma(Y-Y_i)^2$

Y_i is the mean value of Crude oil prices

X_i is the mean value of LNG prices

r = $\boxed{\pm\sqrt{\sum (Y_1 - Y_i)^2 / \sum (Y - Y_i)^2}}$

r^2	0.239
r	0.49