


# Financial Risks and Rewards in LNG Projects: Qatar, Oman, and Yemen

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Oxford Institute for Energy Studies

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Qatar, Oman, and Yemen

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**Note to Second Edition**

After new reliable information became available, we changed the investment cost estimates for the OmanLNG project. All the simulations were repeated with the new estimates, which changed the numerical results slightly, although the conclusions remain the same as in the first edition.

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# LIST OF ABBREVIATIONS

| | |
|---|---|
| AND | average negative deviation |
| APD | average positive deviation |
| bl/d | barrels per day |
| bps | basis points |
| c.i.f. | cost-insurance-freight |
| DAP | Desired Average Price |
| ECA | Export Credit Agency |
| F. P. | foreign partners |
| f.o.b. | free-on-board |
| GUC | Gross Unit Costs |
| LIBOR | interbank lending rate |
| LNG | Liquefied Natural Gas |
| mBtu | million British thermal unit |
| mcf | million cubic feet |
| mt | million metric tons |
| NGL | Natural Gas Liquids |
| NPV | net present value |
| PI | Profitability Indicators |
| PSA | production-sharing agreement |
| RI | Risk Indicators |
| UCG | Unit Costs with Gearing |

# EXECUTIVE SUMMARY

This study looks at financial details and risks of the latest four Middle Eastern Liquefied Natural Gas projects in Qatar, Oman, and Yemen. This is done by simulating cash flows, using benchmark data on sizes, costs, external finance, fiscal regimes, ownership structures, and sales prices. Three aims are central to the analysis:

- To quantify the contributions of different parts of the projects to success or failure.
- To quantify the effects of project finance, fiscal regimes, and ownership arrangements on the exposure of investors to risks.
- To develop unit costs and minimum supply prices for LNG based on actual project details.

The benchmark data used for the analysis are presented in Tables E1 and E2. The first of the two gives details on costs and sizes of the projects, the second continues with fiscal regimes and ownership structures. A comparison shows that the projects are similar in size, with the second Qatari plant, RasGas, smaller than the other three. Investment costs for QatarGas are strongly higher than for the other three plants, explained by bidding conditions and economies of scale in the later plants with bigger train sizes.

**Table E 1: Overview of Sizes and Structures of Middle East LNG Projects**

| *Item* | *Section* | *QatarGas* | *RasGas* | *OmanLNG* | *YemenLNG* |
|---|---|---|---|---|---|
| Investment Costs ($ million) | Upstream | 1200 | 835 | 1300 | 1000 |
| | Downstream | 2800 | 1700 | 1800 | 1900 |
| External Finance Share | Upstream | 0.55 | 0.75 | 0 | 0 |
| | Downstream | 0.70 | 0.75 | 0.8 | 0.6 |
| Output | Gas (mcf/d) | 830 | 660 | 950 | 960 |
| | NGL (bl/d) | 50000 | 40000 | 80000 | 40000 |
| | LNG (mt per year) | 6 | 4.8 | 6.6 | 6.2 |
| Royalty (share) | Gas | 0 | 0 | 0 | 0 |
| | NGL | 0.12 | 0.09 | 0 | 0.25 |
| | LNG | 0 | 0 | 0 | 0.02 - 0.10 |
| Production Share Government | Gas | 1 | 1 | 0 | 0 |
| | NGL | 0.23 - 0.45 | 0.23 - 0.45 | 0 | 0 |

The analysis proceeds in two stages: firstly, it shows calculated cash flows expected from the projects. The calculations are based on assumed prices and costs, especially an assumed oil

price of $ 16 per barrel which stays constant in real terms over the project lifetime, and are used to present the magnitude of revenues and profits expected from the different parts of the projects. It is shown that Natural Gas Liquids form an important part of project economics, but sales revenues from Liquefied Natural Gas are two to three times as high. In fact, LNG sales revenues would be sufficient to run projects with an adequate return on equity investment.

**Table E 2: Debt Finance and Equity Shares in LNG Companies**

| *Company* | *Section* | *Debt* | *Equity Capital Shares* | | | | | |
|---|---|---|---|---|---|---|---|---|
| | | *Share* | *Gov.* | *Foreign Partners* | | | | |
| QatarGas | | | | Mobil | Total | Mitsui | Marubeni | |
| | Upstream | 0.55 | 0.65 | 0.2 | 0.1 | 0.025 | 0.025 | |
| | Downstream | 0.7 | 0.65 | 0.1 | 0.1 | 0.075 | 0.075 | |
| RasGas | | | | Mobil | Itochu | Nissho | | |
| | Upstream | 0.75 | 0.65 | 0.265 | 0.04 | 0.03 | | |
| | Downstream | 0.75 | 0.65 | 0.265 | 0.04 | 0.03 | | |
| OmanLNG | | | | Shell | Total | KOLNG | Mitsub/Mitsui. | Partex |
| | Upstream | 0 | 0 | 0.85 | 0.1 | | | 0.05 |
| | Downstream | 0.8 | 0.51 | 0.3 | 0.0554 | 0.05 | 0.0554 | |
| YemenLNG | | | | Total | Hunt | Exxon | Yukong | Hyundai |
| | Upstream | 0 | 0.6 | 0.133 | 0.133 | 0.133 | 0.133 | |
| | Downstream | 0.6 | 0.21 | 0.36 | 0.151 | 0.145 | 0.084 | 0.05 |

Secondly, in order to reflect the uncertain nature of the LNG business probabilistic ranges of cash flows for the LNG companies are obtained. These reflect revenue volatility because of the link of product prices to oil prices, volatility of interest rates for external finance, and operating cost risks. Probabilistic ranges are obtained from Monte Carlo simulation, i.e. cash flows are calculated repeatedly using prices and costs sampled from probability distributions.

Simulation results are interpreted in terms of the sharing of returns and risks between government and foreign equity partners in the projects. Returns are determined on the basis of Profitability Indicators which show the factor of capital cost recovery, risks are measured in the variability of the Profitability Indicators. Gross project profitabilities before external financing, fiscal regimes, and profit sharing are taken into consideration are roughly equal, with discounted capital recovery of about double the initial investment. External finance

improves project profitabilities considerably, for example discounted capital recovery in OmanLNG is more then eight times equity capital investment.

Project risks are less than 20 per cent, i.e. the average negative deviation of capital recovery factors is under 20 per cent from the mean, except for QatarGas where risk is very low because of a minimum price clause in the LNG sales contract. Gearing increases risks, but returns increase much more significantly.

The study looks in detail into the sharing of risks and rewards between governments and foreign companies. The four projects lead to quite different profit expectations for the partners involved. Government rewards are significantly higher than those of the foreign partners in all the projects, even in the case of Yemen because of very low government equity capital contribution, whereas risks are pointedly higher for the foreign partners.

The paper compares the variability of gross project cash flows with the variability of government and foreign partner cash flows for each of the projects. This shows that LNG company agreements achieve risk mitigation for the national governments, mainly through increasing government revenues above equity contributions. Foreign partners in contrast have to accept increases in risks compared to geared project risks.

The study then uses the data generated to determine unit costs and minimum supply prices for the projects. Unit costs are presented for the projects on an *a priori* basis, without taking external finance, and actual project arrangements into account. Gross Unit Costs lie between $ 1.80 per million British thermal unit (mBtu) for QatarGas and $ 1.30 per mBtu for OmanLNG excluding transport costs. These estimates are then compared with estimates including cost reductions through external finance (gearing). It is shown that gearing reduces unit costs by about 10–12 per cent.

**Table E 3: NGL Prices and Minimum Supply Prices for LNG (in $ per mBtu f.o.b.)**

| | *NGL Price* | *LNG Price* | | | |
|---|---|---|---|---|---|
| | | *QatarGas* | *RasGas* | *OmanLNG* | *YemenLNG* |
| Oil Price $ 13 | 2.19 | 2.06 | 1.68 | 1.28 | 1.76 |
| Oil Price $ 16 | 2.69 | 1.88 | 1.50 | 1.28 | 1.62 |
| Oil Price $ 19 | 3.20 | 1.70 | 1.33 | 1.28 | 1.49 |

Actual project arrangements lead to a sharing of returns from the projects which is not proportional to equity capital contributions. Royalties and upstream production shares mean

that the government receives a higher share of revenues than its share in equity capital. This unequal sharing means that the foreign investors receive low returns if sales prices are equal to unit costs. In order to estimate minimum supply prices for the projects, the study looks at the prices at which foreign investors would receive adequate returns, which are above unit costs by a significant margin.

Minimum supply prices for gas depend on actual project arrangements, and the level of NGL production, because of the extra revenue that projects gain from NGL sales. The exception is OmanLNG where minimum supply prices for gas are independent of NGL revenues, because the foreign partners receive fixed returns in the upstream section. Estimated minimum supply prices for gas for different prices of oil and NGL are shown in Table E3.

The last chapter reports results of counterfactual simulations. QatarGas has the disadvantage of high investment costs, but is protected by a minimum price clause, agreed in a letter of intent with the Japanese buyer. A formal pricing contract is under negotiation. Simulations of cash flows are carried out with a waiver of the minimum price clause, to show a 'worst-case' scenario of the negotiation outcome. This shows QatarGas returns decreasing, and risks increasing, making QatarGas the least attractive of the projects. There is an estimated 20 per cent probability that the NPV of foreign partner cash flows will be negative. OmanLNG on the other hand is extraordinarily robust. Counterfactual simulations show that returns and risks will be within the range of the other three projects even if no additional volumes in excess of the current contract with the Korean Gas Company are sold.

Over the time elapsed between the finalising of each of the four projects, government returns increased at the cost of foreign partner returns. This is due to a positive historical situation with strong demand expectations in Asia, and high liquidity in the international financial markets. Demand expectations for the Asian market have been revised downward, and lenders' willingness to support projects aimed at the Asian market are significantly reduced. The fast creation of three LNG projects in the Middle East over the first half of the 1990s is the result of a historical opportunity which might not present itself again soon. The prospects for the Yemeni project, which missed the window of opportunity by only two years or so, do not look too good, if no new markets other than the traditional Asian market can be found.

The Middle Eastern LNG projects are shown to be highly profitable ventures on the whole, rightly called the 'cash cows' of the industry. With firm oil price expectations, LNG prices could come down significantly, opening the way for Middle Eastern gas deliveries to Europe.

# 1. INTRODUCTION

Natural gas is increasingly the energy source of choice because of convenience, high thermal efficiency, and relative cleanliness when compared with oil or coal. Because of its gaseous nature transport poses a major obstacle to a more thorough penetration of world-wide energy markets. This obstacle can be overcome by long-term investments in transport infrastructure. This paper looks at projects designed to overcome the geographical limitations of the utilisation of Middle Eastern natural gas: the latest four Liquefied Natural Gas (LNG) projects in the region.

LNG projects require high capital investments and operate in an uncertain environment. Prices are mostly set by bilateral purchase and sales agreements in an imperfect market environment. Mutual trust and dependability over a long time horizon are paramount. In addition, sales prices have so far mostly been linked to the highly volatile world oil price. This link to oil prices has become stronger over time, as floor and ceiling prices have disappeared. The volatility of prices is therefore of increasing concern for LNG investors. Investors have to be convinced that the economics of a proposed venture are robust enough to service long-term debt and afford an adequate return on equity investment.

This study looks at the determinants of this robustness. We look at financial details and risks of LNG projects by simulating cash flows, using benchmark data on sizes, costs, external finance, fiscal regimes, ownership structures, and sales prices. Three aims are central to the analysis:

- To quantify the contributions of different parts of the projects to success or failure. The paper looks at the contribution of project finance and Natural Gas Liquids (NGL) sales to increasing the profitability of the projects, and the effects of fiscal regimes and ownership arrangements on the sharing of returns.
- To quantify the effects of project finance, fiscal regimes, and ownership arrangements on the exposure of investors to risks. The paper simulates the variability of LNG project cash flows in an uncertain world using probabilistic prices and costs. The results are interpreted in terms of increasing or mitigating risks, and risk sharing between joint venture partners.
- To develop unit costs and minimum supply prices for LNG based on actual project details, including NGL revenues, finance, fiscal regimes, and ownership structures. These minimum supply prices show LNG competitiveness in potential markets.

## Overview

This study compares four LNG export projects all of which were conceived within a relatively short period of time. These are in historic order the QatarGas and RasGas ventures at the Ras Laffan peninsula in Qatar, OmanLNG in the Sultanate of Oman, and YemenLNG in the Yemen. QatarGas went on stream in January 1997 after the completion of its first of three trains whereas RasGas and OmanLNG are under construction. The Yemeni venture is in an advanced planning stage having taken the hurdles of government and parliament approval in 1997.

The benchmark data needed for the analysis are presented in Sections 2 and 3. The first of the two gives details on costs, sizes, and sales contracts of the projects, i.e. operating and capital costs, production volumes of gas, Natural Gas Liquids (NGL), and LNG, and on the sales contracts signed and expected. Section 3 then continues with fiscal regimes and ownership structures, i.e. the level of royalties, government production shares in production-sharing agreements, and equity and profit shares.

The rest of the study simulates cash flows of LNG export projects. The analysis proceeds in two stages: Section 4 shows calculated cash flows expected from the projects. The calculations are based on assumed prices and costs, and are used to present the magnitude of revenues and profits expected from the different parts of the projects. Especially, cost savings obtained through the use of external finance instead of equity capital are highlighted. Results are presented first for an example year of full capacity operation, and then in terms of the net present value (NPV) of revenues and costs over the lifetime of the project.

In order to reflect the uncertain nature of the LNG business we then use Monte Carlo simulation in Section 5 in order to obtain probabilistic ranges of cash flows for the LNG companies. LNG projects operate in the highly uncertain world of the hydrocarbon industry. Their products are sold at prices usually linked to the price of oil and revenues are volatile. Because of the high investment costs, they have to rely on large amounts of external debt which introduces an influence of interest rate volatility. In addition, operating costs are not known for certain in advance and vary from year to year.

Monte Carlo simulation means repeatedly calculating cash flows using oil prices, interest rates, and operating costs which are sampled from probability distributions. We use one thousand calculation 'runs' for each of the LNG projects to obtain cash flows and a probability distribution for their occurrence. Section 5.1 describes the methods and the probability assumptions used. In Section 5.2 the results of Monte Carlo simulations of yearly

cash flows are presented. This shows the exposure to balance sheet losses for the companies. In Section 5.3. the net present values of cash flows are presented in the form of probability distributions. The sensitivity of net present values of cash flows to changes in the oil price are presented in the form of cash flow functions in Section 5.4. These give a perspective on exposure to downside risk and participation in upside potential, and on government taxation of LNG projects.

Section 5.5 uses the data generated to look more closely at risk and reward sharing. For this, simulated NPVs of cash flows are transformed into Profitability Indicators based on equity capital investment, and volatility of returns is represented by Risk Indicators. The section then presents increases in returns and risks associated with external project finance (gearing), and the sharing of rewards and risks between project partners, i.e. the national government on one side and the foreign partners on the other.

In Section 6 the data generated in Sections 4 and 5 are used to determine unit costs and minimum supply prices of LNG. In the literature, LNG projects are often described in terms of the netback value of gas. This is estimated using the maximum delivered price of gas at which the consumer, usually an electricity generator, would be indifferent between using gas or other sources of energy. The netback value is then this maximum price minus re-gasification, transport, and liquefaction costs, or total c.i.f. delivery costs per unit of gas delivered. This section therefore presents liquefaction costs per unit of gas.

Three different estimates are shown: i) total costs per unit of output including total investment and operating costs (Gross Unit Costs, GUC), ii) unit costs taking into account a reduction in the net present value of investment costs through the use of external finance (Unit Costs with Gearing, UCG), and iii) the minimum prices at which investors would be willing to sell taking into account external finance, fiscal regimes, and ownership structures (Desired Average Price, DAP). The last estimate shows the minimum level of prices, given actual project arrangements, at which the NPV of foreign partner cash flows is zero. The differences between the three estimates show the implications of debt finance and fiscal regimes on prices.

The three estimates are looking at unit costs and prices of the average unit of hydrocarbons produced. Given that the price for NGL is determined in the world market, it is most interesting to look at the price of gas for given prices of NGL. If investors expect to receive a high price for NGL, they will be willing to lower the price formula which links gas prices to the price of oil. Section 6.4 therefore shows Minimum Supply Prices for Gas for given levels of oil prices.

In the different parts of Sections 5 and 6, it is shown how QatarGas benefits from a minimum price guarantee specified in the initial pricing agreement with the Japanese buyer, which so far is still under negotiation. In Section 7, counterfactual simulation is used to look at the possible implication of the negotiations, i.e. a waiver of the minimum price clause for QatarGas. Also, OmanLNG has contracted only about two-thirds of its planned capacity to the Korean Gas Company, and the remaining one-third was planned to be delivered to Thailand. But because of the economic difficulties encountered at the end of 1997 the country has shelved plans for LNG imports from Oman for the foreseeable future. Section 7 therefore looks at the 'worst-case' scenario for OmanLNG, where the company operates at only two-thirds of capacity.

Of course, oil price, interest rate, and operating cost risks are not the only risks faced by investors in the LNG business. In addition we can list geological risk regarding the size of natural gas reserves, political risk regarding changing government regulation and taxation, *force majeure* risks of all kinds, and so on. But all of these different sources of uncertainty are very complex and not easily quantified. By looking only at price and cost risks while keeping these other risks in mind we can develop lower bound scenarios, meaning that if a project looks just about rewarding enough considering price risks, the existence of additional sources of risk will probably tilt the decision against it.

# 2. COST INDICATORS, SIZES AND MARKETING

## 2.1. Overview

In the Middle East the first LNG project started deliveries in 1977 from Abu Dhabi.[1] It remained the only such plant until the first of the projects of interest in this paper – the QatarGas plant in the Ras Laffan peninsula in Qatar – started commercial operations in January 1997. The second half of the 1990s witnessed a remarkable proliferation of LNG export schemes in the region with the second Qatari venture, the RasGas plant, and the Omani and Yemeni ventures we are looking at in this paper. Another project in Egypt is at a very early planning stage and is therefore not included in this analysis.

Liquefaction is the best option if gas is to be transported over long distances, say above 2000 or 3000 kilometres (the distance between Qatar and Japan, for example, is 6400 nautical miles or 11,500 kilometres). The technology is simple though capital intensive. It consists mainly of giant refrigeration units designed to freeze the gas to a temperature below –161.5 degrees Celsius, the boiling point of Methane. Other gases such as Ethane and Propane have boiling points much above and are separated during the cooling stage. The liquefied gas delivered to consumers is therefore very pure and can usually command a small price premium over pipeline gas.

Each operation cycle with gas inlet, the refrigeration unit, separation equipment for non-Methane components of the gas, and liquid product storage before tanker loading is called a train. LNG ventures are seldom planned with less than two trains to benefit from economies of scale of supporting infrastructure. The gas in a liquid state is pumped onto tankers specially designed to contain the cold for a journey of several weeks. At the destination the liquid is re-heated and the gas is piped to the consumer, e.g. a gas fired power producer.

Using liquefaction plants and tankers is a less flexible option than building pipelines because load variation reduces efficiency of the plants and storage is costly because of boil-off, i.e. evaporation of gas due to re-heating in storage tanks or during transport. This is also the reason why LNG tankers operate at higher speeds than oil tankers. This reduced flexibility of the LNG chain means that investors look for projects with sales contracts with low volume variability, which usually means customers are base-load power producers in new markets or

[1] The first commercial export plant was built in Algeria in 1964.

big distribution companies in mature markets. The electricity markets in potential buyer countries and the position of gas-fired power producers in those markets are therefore of great importance for the viability of a LNG project.

On the other hand, liquefaction and tanker transport is geographically flexible, whereas a pipeline obviously is not, unless it connects to a broad pipeline grid as in North America. This flexibility is greatly improved if the LNG project commands its own ships, i.e. sales are contracted on a c.i.f. basis. When a company has signed an f.o.b. contract, as OmanLNG did with the Korean Gas Company, it is severely reduced in its marketing flexibility (the Korean buyers insisted on f.o.b. sales in order to ensure that ship building contracts would end up in the country, without costly bidding).

Having geographical flexibility means a mitigation of political or *force majeure* risks in buyer countries, but also that additional production volumes can be sold on a spot basis. Frequently, base-load buyers contract for a build-up period of several years during which sales volumes rise step wise to the plateau level, at which it then stays for at least twenty years. Such build-up periods help the buyer to develop an infrastructure and a market for the gas. At the same time, the liquefaction plant is fully operational, because the technical start-up period is very short. Selling excess capacity can mean large extra revenues in the crucial early years of a project. These extra earnings opportunities are more of a speculative nature and are ignored in the calculations in this study.

In each of the projects this paper looks at, two sections are distinguished, upstream and downstream sections. In the upstream section, production wells, gathering pipelines, gas treatment facilities, and transport pipelines to the liquefaction plant are included. An exception is Oman, where the upstream section comprises only of wells and gas gathering pipelines, and the rest of the infrastructure is counted as part of the downstream section because of financing and ownership arrangements in the project. The downstream section then comprises of the liquefaction plant itself, storage tanks, which make up a sizeable part of investment costs, and jetty installations. The harbour is not necessarily built by the LNG project company.

The economics of the projects and expected payoffs for the partners involved are mainly influenced by three factors: the investment costs of the plants, which depend heavily on the technology employed and the amount of competition in the construction tenders, the sales prices usually agreed in bilateral negotiations between LNG company and buyers, and the finance, fiscal, and ownership structure which is the outcome of the legal situation and negotiations in the project country. This section is mainly concerned with the first two of the

factors. We present size and cost indicators for the four LNG projects, and discuss sales contracts.

**General Cost Assumptions**

For all four plants we use the same operating and transport cost estimates. Operating costs in the upstream section of the projects are measured per unit of gas output, and are estimated at $ 0.24 per million British thermal unit (mBtu) or $ 245 per million cubic feet (mcf). In the Monte Carlo simulations in Section 5 operating costs are sampled from a probability function which produces a lognormal distribution with a standard deviation of 20 per cent of the mean. In the downstream section of the projects operating costs per unit of LNG output are estimated at $ 0.41 per mBtu, and in the probabilistic simulations they also have a deviation of 20 per cent.

The transport of the LNG to Japan or Korea requires specialised tankers which typically have a capacity of 135,000 cubic metres and come at a price of $ 270 million each. In all of the projects of interest here the ships are owned by shipping consortia and chartered by the LNG companies or the LNG importers on a long-term charter which means transport is a running cost instead of additional capital expenditure. For example, the QatarGas project requires ten such ships at a capital cost of $ 2.7 bn. The leasing arrangement means this capital expenditure is kept out of the books of QatarGas. Instead transport costs are counted as running costs and are estimated at $ 1.10 per mBtu.[2] This paper therefore does not make a distinction between f.o.b. and c.i.f. sales, and does not take into consideration the extra revenues which might be obtained through spot sales of additional volumes of LNG.

This section presents the four LNG projects compared in this paper in terms of sizes and costs, and in Section 3 ownership and financing structures are presented. Table 1 gives an overview of the indicators discussed in this section. It shows indicators for size and fiscal regimes for the four projects. It starts with total investment costs for upstream and downstream sides in the first two rows. Next follow output quantities for raw gas, NGL, and LNG. Royalties and upstream production shares of the government are presented in rows 8 to 12. Note that investment costs shown in Table 1 are nominal total funding requirements as stated by project documents. These include contingency funds and capitalised external finance costs.

[2] All running cost estimates are taken from Yamani (1997).

**Table 1: Overview of Sizes and Structures of Middle East LNG Projects**

| *Item* | *Section* | *QatarGas* | *RasGas* | *OmanLNG* | *YemenLNG* |
|---|---|---|---|---|---|
| Investment Costs | Upstream | 1200 | 835 | 1300 | 1000 |
| ($ million) | Downstream | 2800 | 1700 | 1800 | 1900 |
| External Finance | Upstream | 0.55 | 0.75 | 0 | 0 |
| Share | Downstream | 0.70 | 0.75 | 0.8 | 0.6 |
| Output | Gas (mcf/d) | 830 | 660 | 950 | 960 |
| | NGL (bl/d) | 50000 | 40000 | 80000 | 40000 |
| | LNG (mt per year) | 6 | 4.8 | 6.6 | 6.2 |
| Royalty (share) | Gas | 0 | 0 | 0 | 0 |
| | NGL | 0.12 | 0.09 | 0 | 0.25 |
| | LNG | 0 | 0 | 0 | 0.02 - 0.10 |
| Production Share | Gas | 1 | 1 | 0 | 0 |
| Government | NGL | 0.23 - 0.45 | 0.23 - 0.45 | 0 | 0 |

Sources: Data obtained from *Middle East Economic Survey, Cedigaz News Report, Gas Matters*, different years; and company sources.

## 2.2. Sizes and Structures

### QatarGas

QatarGas was first incorporated in 1984 but no progress was made during the following eight years, after which British Petroleum decided to withdraw from the project and Mobil took over the project leadership. As is the case for all the other LNG companies under scrutiny here, project planning only really took off after a major customer for the LNG was found. On 13 May 1992 QatarGas signed a 25-year supply contract over 4 mt per year with Chubu Electric, with a start-up date of January 1997 and a build-up period of four years.

The project was then designed as a two-train liquefaction plant with supporting infrastructure, but in 1994 Chubu exercised an option for another 2 mt per year on behalf of Japanese utilities and it was decided to build an additional third train. The first production train started commercial deliveries in January 1997, and the second and third trains are under construction. Each train has a design capacity of 2 mt per year.

Upstream and downstream parts of the project are two distinct ventures, with different terms of ownership and separate costs and revenues accounting. The upstream section is designed to produce 830 million cubic feet per day (mcf/d) of natural gas and 50,000 barrels per day (bl/d) of NGL. But it receives revenues only from the sales of NGL to the international market, because raw gas sold to the liquefaction plant is owned by the government and revenues have to be passed on. Gas is sold to the downstream section at a fixed price of $ 0.5 per mBtu.

Not all of the sales revenues from the production of NGL are credited to the upstream section of the project because liquids are subject to a 12 per cent royalty and a production-sharing agreement (PSA) between the government and the QatarGas partners. The PSA leaves the QatarGas partners 77 per cent of production during the first seven years and later the share depends on the ratio of accumulated revenues to costs. It decreases to 65 per cent after the initial seven years and 55 per cent towards the end of the 25 years. Total upstream investment is about $ 1.2 bn. In addition to the sliding production shares QatarGas has the possibility to defer royalties on liquids and the payments for gas purchased from the government when revenues are low to be offset against higher revenues in later years. This gives added protection of cash flows in the early years of the project.

The downstream liquefaction project will eventually produce 6 mt per year of LNG at a total investment cost of $ 2.8 bn, of which $ 2 bn cover the initial two trains and $ 800 million are needed for the third train. This shows the substantial economies of scale benefiting the expansion to a third train: an increase in design capacity by 50 per cent is achieved at an additional investment of some 35 per cent. The third train was already an option in the original construction contract and changes in technology or the construction market are not responsible for lower costs. In the bidding process for QatarGas, Mobil paid for a bid by Foster Wheeler although it was clear that a Japanese consortium would win the tender because of the exclusive involvement of Japanese finance and buyers. The presence of a Western bidder was thought to put pressure on costs.

**RasGas**

The second Qatari LNG project signed a letter of intent with Korea Gas Corporation (KGC) in December 1992, a final contract was signed in October 1995 for deliveries starting in 1999. The venture profited greatly from the experiences and trust gained with the QatarGas project,

and also from existing infrastructure. Project design and negotiations with the government could be concluded much faster once the QatarGas precedent had been established. The project is a strategic asset for the leading foreign investor, Mobil, which is facing a terminal decline in LNG production from the Indonesian Arun project. RasGas enables Mobil to keep its position as a leading international LNG producer.

The project has a sales agreement with the Korea Gas Company for 4.8 million tons of LNG per year over a period of 25 years starting in 1999. This requires the construction of a two-train liquefaction plant, although a third train is planned. Total investment costs for RasGas are put at $2.535 bn, with external finance covering 75 per cent of this. The company benefits from existing infrastructure at the Ras Laffan peninsula, especially the port facilities constructed for QatarGas. Technical improvements and open competition in the tender mean additional cost savings, with the total downstream capital expenditure at only $ 1.7 bn, compared with $ 2.8 bn for the QatarGas plant. Upstream investment costs are put at about $ 835 million. The upstream side of the RasGas project is designed to produce 660 mcf/d of natural gas and 40,000 bl/d of NGL.

**OmanLNG**

The Omani LNG project was born out of competition between Royal Dutch/Shell as the leading Omani oil producer and a rival plan of a natural gas pipeline to India promoted by entrepreneur John Deuss. Shell saw its leading position in Oman challenged and therefore had to pre-empt the rival gas scheme. The project is regarded as highly profitable, but even without this the company might have gone ahead with it anyway and commercial considerations might have taken second place. Planning started as late as February 1992, when the government of Oman signed a letter of intent with the Western partners in Petroleum Development Oman (PDO) to conduct a feasibility study. OmanLNG was formed in June 1993, in May 1996 a consortium of Chiyoda and Foster Wheeler was selected as lead contractor. Start-up is planned for early 2000, and so far construction has progressed ahead of schedule.

The project will consist of the gas wells and gathering system, a 370 km pipeline from the gas fields to the coast, the liquefaction plant and a deep sea harbour. LNG will be sold f.o.b., and the buyers arrange transport. Although the project is bigger than the QatarGas

venture, it is designed on the basis of only two trains with a capacity of 3.3 mt per year each, instead of the three 2 mt per year in the QatarGas project.

Total upstream investment is about $ 1300 million which includes the 65 to 70 wells and a gathering system, the pipeline from the gas fields in the interior of the country to the coastal location of the liquefaction plant, and gas treatment facilities. The upstream section is developed and operated by Petroleum Development Oman (PDO), a joint venture of the national Omani OGC and foreign companies, mainly Shell, but owned by the Omani government, i.e. PDO receives a service fee for upstream development giving it a 12 per cent return on costs. Revenues from the sales of gas and liquids above the agreed 12 per cent return accrue to the government.

The Omani gas fields are thought to contain a relatively high amount of condensates and other liquids. Production is designed to reach 950 mcf/d of gas and 80,000 bl/d of NGL, and 6.6 million tons of LNG per year. Gas is sold to the downstream section at a fixed price increasing over the lifetime of the project, with an initial price of $ 0.31 per mBtu. The gas price reaches $ 0.60 after five years, and $ 0.75 after the first ten years. The total downstream funding requirement for OmanLNG is estimated at $ 2.5 bn, of which $ 1.2 bn cover the actual construction of the liquefaction plant whereas the rest are, storage tanks, contingency funds, and funded financing costs.

**YemenLNG**

The natural gas reserves in Yemen were discovered by a consortium consisting of Hunt, Exxon, and Yukong. In August 1992, the concession holders completed a preliminary feasibility study for an LNG project. In the production-sharing agreement under which the gas was discovered the legal rights to the gas were unclear and the Hunt/Exxon/Yukong consortium and Enron were competing for these rights. Protracted negotiations about the project followed, with the initial concession holders pulling out, Enron claiming the final breakthrough several times and a civil war between North and South Yemen interrupting the negotiations. The government of Yemen finally invited new bids in the autumn of 1994 and appointed Total as lead operator in 1995, a major breakthrough for the company after it secured only a very minor position in the Omani project.

The Yemeni LNG project is planned to use a two-train liquefaction plant which was first intended to have a capacity of only 5 mt per year. With LNG technology development leading to ever bigger liquefaction units, it seems more reasonable to expect that capacity will

be 6.2 mt at least. The project also contains a pipeline from the producing area to the plant, and another to Sana'a to provide local gas supply, as well as gas treatment and NGL extraction facilities. Gas production will reach 860 mcf/d for the liquefaction plant and 100 mcf/d for local distribution in Sana'a, and NGL production is forecast at a relatively modest 40,000 bl/d. The gas is produced on a cost-plus basis, where costs are set at $ 0.30 per mBtu including capital recovery, and a service fee is added amounting to a nominal total of $ 900 million over the lifetime of the project, or 12.3 cents per mBtu (if production is 800 mcf/d over 25 years).

The upstream section also receives revenues from the sale of condensates, which have to be sold domestically at 75 per cent of world prices as far as possible and the government receives a 10 per cent royalty on any exported surplus. The LNG sold is also liable to royalty, which starts at 2 per cent over the first eight years of commercial operation, and increases in stages up to 10 per cent.

Total investment outlays for YemenLNG are estimated at $ 2.9 bn, with $ 1 bn for the upstream, and $ 1.9 bn for the downstream section, less than for the Omani venture to account for some additional cost savings which might occur when YemenLNG will finally be built.

## 2.3. Sales Agreements and Pricing

### Pricing Formulas

Liquefied Natural Gas around the world is usually sold on the basis of a pricing formula which links the price of LNG to the price of crude oil. The exact pricing formulas are usually considered commercial secrets and not available in the public domain. This study is based in estimates published in the *Middle East Economic Survey*. Two distinct formulas are used, one applying to sales from QatarGas, the other to OmanLNG. The Qatari formula calculates c.i.f. prices of LNG, whereas Omani production is sold on a f.o.b. basis.

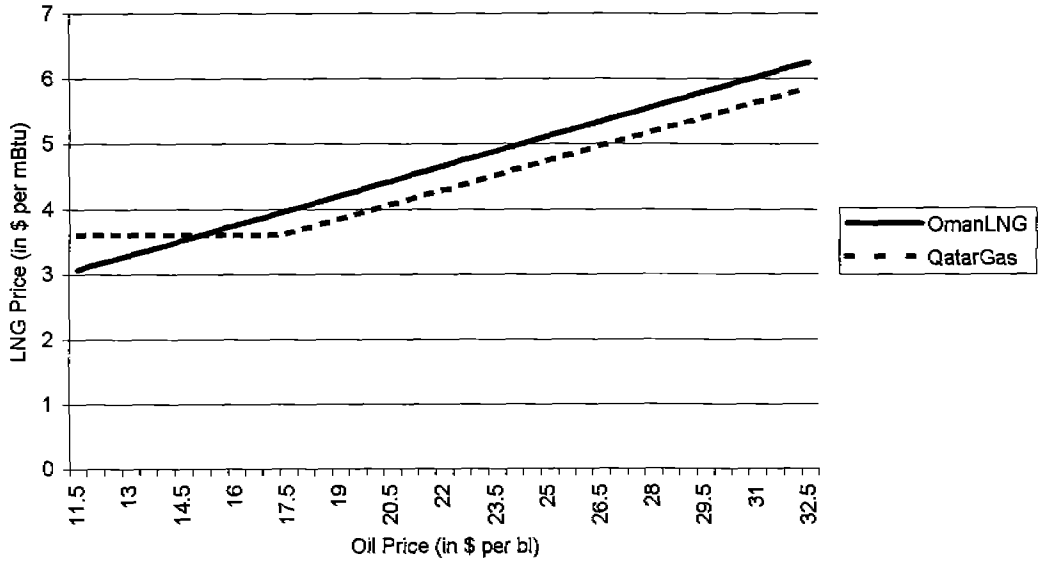
The pricing formula for QatarGas originally agreed upon was in line with other Japanese LNG contracts. Most Japanese contracts calculate LNG prices by taking the Japanese customs clearing price for a basket of crude oil and multiplying with a factor of 0.1485 (this is equal to using a conversion factor of 6.73 mBtu per barrel of oil). A fixed factor is then added to the price, which is between $ 0.60 and $ 0.90 per mBtu in the different

Japanese import contracts.[3] For the calculations here we have used a fixed factor of $ 0.80. The fixed factor partly takes account of the relatively fixed transportation costs for the gas.

Most LNG pricing formulas including the initial Qatari one had a price floor built in, i.e. the oil price link was severed at a certain level below which gas was to be sold at a fixed price. The Japanese buyer agreed to a minimum price of $ 3.60 per mBtu in a letter of intent.

The Omani price formula calculates LNG prices on the basis of the Japanese customs clearing price for crude oil on a f.o.b. basis. The oil price is multiplied by a factor of 0.1515, or a conversion factor of 6.6 mBtu per barrel. It does not contain a fixed element nor does it specify a minimum price.[4] It leads to a steeper link between gas and oil prices. This is shown in Figure 1 which plots the LNG prices against oil prices. Oil prices are shown on the horizontal axis, LNG prices on the vertical axis. To make the Qatari and Omani formulas comparable, a fixed transport cost of $ 1.10 per mBtu has been added to the Omani prices.

**Figure 1: Oil Prices and LNG Sales Prices (in $ per mBtu, c.i.f.)**




Note: Horizontal axis shows oil price in $ per barrel (Arabian Light f.o.b.), vertical axis shows LNG price in $ per mBtu, c.i.f.; Qatari and Omani price formulas in comparison.

The two graphs in Figure 1 show the price of LNG delivered to Japan depending on the f.o.b. price of Japanese crude oil imports. The Qatari formula includes a minimum price of $ 3.60

[3] See *MEES*, 41:7, 16 February 1998.
[4] See *MEES*, 39:25, 18 March 1996.

per mBtu, which is equal to the sales price at about $ 17.5 per barrel of oil. The two graphs cross at an oil price of $ 14.5 per barrel, where the Omani sales price reaches $ 3.60. Above this crossing point, Omani LNG sales are priced about $ 0.30 per mBtu above Qatari sales. At the mean oil price assumption of $ 16 used throughout this paper, Omani sales revenues are substantially above Qatari revenues. The main buyer of Omani LNG, the Korea Gas Company, initially agreed to a minimum price in the negotiations with OmanLNG.

This was later waived in return for an increase in volume, and it seems also a relatively high price when compared with the Qatari formula. Also, it should be noted that the Omani contract is made on a f.o.b. basis, which means OmanLNG forgoes considerable extra earnings possibilities because it lacks means of transport to place additional volumes arising from excess capacity. Both higher downward flexibility of prices and less flexibility in sales volumes are compensated with higher base load prices.

The two graphs in Figure 1 appear almost parallel (the slope is 6.73 for QatarGas and 6.6 for OmanLNG). A fixed transport cost adjustment has been used, although transport costs vary with the price of oil or gas, because a part of transport costs is the boil-off of LNG. At low prices, the price of OmanLNG would therefore be above the graph shown in Figure 1, at high prices below. Prices would then show less risk than shown in the figure.

The remainder of this section discusses sales contracts for the four projects. It is assumed that RasGas and YemenLNG will sell at the same prices as OmanLNG, RasGas because the buyer is KGC as in Oman, whereas YemenLNG has not progressed sufficiently to know details about pricing.

**QatarGas**

In May 1992 Chubu Electric, a Japanese power producer, signed a contract for the purchase of 4 million tons per year (mt per year) over 25 years starting early 1997, with a build-up period of four years. In 1994 Chubu Electric exercised an option over an additional 2 mt per year on behalf of seven other Japanese buyers, for which a third train has to be built. The construction contract for the liquefaction plant was awarded to Chiyoda and two Qatari companies, MECON and MIDMAC, and the original bid included an option for the third train.

The LNG produced by QatarGas is sold to the Japanese buyers on a cost-insurance-freight (c.i.f.) basis with the exact price formula still under negotiation a year after the project started deliveries. The buyers have agreed to a minimum price of $ 3.60 per mBtu in a memorandum of understanding, and it seems clear that the price formula will link the LNG

price to the average price of crude oil imported into Japan. The preliminary price was set at $ 4.10 per mBtu for the first three months of 1997, and reduced to $ 4 per mBtu for the next quarter.

It seems quite obvious that the Japanese buyers are not anymore willing to sign the minimum price provision, given that oil price expectations are now considerably below what they were two or three years ago, and given that both RasGas and OmanLNG have signed contracts without minimum price provisions. It is therefore expected that a final price agreement will see a combination of increasing the LNG price relative to the average Japanese price and a lowering or abolishing of the minimum price. The impacts of different bargaining outcomes are simulated in Section 7.

**RasGas**

The company initially signed a letter of intent with the Korean Gas Company. The Korean buyer agreed to the lifting of 2.4 mt per year of LNG at a minimum price of $ 3.60 per mBtu c.i.f. as was agreed for the QatarGas venture. In March 1996 however, the Korean Gas Company agreed LNG sales with Oman without such a price floor and then tried to achieve the same terms with RasGas. Throughout the negotiations with both companies, the Koreans could use their strong market position to play the two LNG companies off against each other.

As a precondition for contracting another 2.4 mt per year of LNG the minimum price for the whole agreement was therefore waived. Because financing arrangements, and especially the sales of bonds in international markets, had already been made on the basis of the quite high minimum price provision, Mobil, the major foreign shareholder in the RasGas venture, put up an extra line of credit able to guarantee debt service obligations of RasGas once the f.o.b. LNG price fell below $ 1.90 per mBtu, which is equal to a landed price of $ 3, or 60 cents below the QatarGas minimum price. The credit guarantee carries an upper limit of $ 200 million.

**OmanLNG**

Early in 1996 the company signed an agreement with the Korean Gas Company for the delivery of 4 million tons of LNG per year over 25 years starting in 2000. A letter of intent with Thai LNG Power Co. for 2.2 mt per year was signed in June 1996 for deliveries starting

in 2003, but this has recently been shelved because of the economic difficulties in the country. It is currently not clear where these extra volumes will be placed.

The downstream side of the project will sell 6.6 mt per year of LNG. The Korean purchases are priced on a f.o.b. basis and linked to Japanese crude oil imports. The conversion factor used is 6.6 mBtu per barrel of crude oil. The Thai tranche was to be priced on the basis of Japanese crude oil imports, Japanese coal imports, and the US consumer price index, with equal weights. As mentioned above, the Omani price formula leads to significantly higher prices than the average Japanese import formula. The Korean Gas Company seems to have made considerable concessions to OmanLNG in order to arrive at a contract without a minimum price clause. Strong demand expectations in Korea have obviously weakened the buyer's bargaining position, although two LNG ventures were competing for Korean contracts.

**YemenLNG**

The company has signed memoranda of understanding with Korea and Turkey, but has not contracted any buyers. With the economic downturn in Asia it seems unlikely that Korea is going to sign a contract any time soon, and the price at which Turkey would be willing to buy LNG might not be sufficient to go ahead with the project, given high transport costs, where shipping through the Suez canal alone costs about $ 0.25–0.35 per mBtu.

The joint venture agreement between the government and foreign partners specifies a minimum transfer price for LNG of $ 2 per mBtu f.o.b. for the government. According to the agreement the government receives a guaranteed income from the joint venture, which is equal to its profit share at the floor price of $ 2 per mBtu. If the realised sales price falls below this minimum, the company has to advance the hypothetical government share out of the foreign partner share, but can offset the advance against excess profits, if they materialise in later years.

For the calculations the paper assumes sales prices for YemenLNG will equal the Omani contract. This is highly optimistic given the downward revision of Asian LNG demand expectations, and the build-up of excess capacity in the LNG market. The Yemeni project might have to sell at reduced prices to find customers in the medium-term future.

## 2.4. Concluding Comments

The four projects presented here are similar in size with the exception of RasGas, which should be expanded by a third train in the future. It should be noted that in all cases a large amount of NGL will be produced alongside the natural gas, a vital factor for the profitability of the projects. A comparison of the investment cost data makes it clear that even over the short period of time which has elapsed between the conception of QatarGas and OmanLNG, for example, technological advances and more open bidding for the construction contracts have allowed significant cost savings in the construction phase. Also, later plants are bigger than older units and therefore can derive benefits from economies of scale. The train size has increased from 2 mt per year to more than 3 mt per year and this has meant that even one-train developments might be profitable, as in the Trinidad project currently under construction.

Partly because of these cost reductions, but also because of the high sales price it achieved with the Koreans, the Omani venture is the first large LNG plant to be built without prior signing of sales contracts for the entire production volume, which previously was regarded as essential in order to secure financing of capital costs. Risks taken by investors counting on strong Asian demand to place the uncommitted one-third of LNG capacity can be regarded as small given the excellent project economics and the high sales price at which Korea contracted supplies.

One major uncertainty in the data provided in this section is the often mentioned possibility to exceed design capacity production levels. It is often argued that capacity increases of 20 to 25 per cent can be achieved at only 10 per cent increase in investment costs and that the additional volumes can be sold at high profit on a short-term basis. In addition, expansion of existing plants, especially the construction of a third train for the RasGas plant, is always cheaper than greenfield projects. This means additional free capacity could arrive at times of sluggish demand for LNG. These views make it look increasingly unlikely that YemenLNG will find enough buyers in the next five to ten years to start construction.

# 3. OWNERSHIP AND FINANCING ARRANGEMENTS

## 3.1. Overview

The large investment costs associated with the LNG ventures described above make it difficult for any one company, whether a national oil company of the resource producing country or an international oil company, to undertake the project on its own. Joint ventures are set up in order to share risks and rewards by specifying the equity shares of partners in the project, and also the amount of external finance required. The exact form these joint ventures take is dependent on a range of factors, which seem to make every contract unique. Commonly, long negotiations are necessary before the signing of an agreement.

Table 2 presents debt finance and equity capital shares in the LNG companies as specified in the joint-venture agreements. For each of the four projects, the table shows the debt finance share of total project funds needed, which is raised as project finance from international banks and the bond markets in the first column. The next columns show the sharing of the remainder of funding between the government in the second column and the foreign partners in the next columns. Upstream and downstream shares are distinguished. Profit sharing applied to the cash flows calculated later in the paper follows the equity shares shown in the table, except for the YemenLNG project, where government profit shares vary over the lifetime of the project and increase above the equity share in later years. The projects will be presented in detail in the next sections.

**Project Finance**

The financing of the LNG ventures described here uses a majority share of external debt capital, with the share of total funding requirements shown in the first column of Table 2. In all four ventures this takes the form of non-recourse project finance, i.e. the debts are guaranteed by the assets of the LNG ventures only and not by the partners' assets (except for the extra credit guarantee given to RasGas when the minimum price provision with the Korean Gas Company was waived). The creditors are international banks but in the cases of RasGas and OmanLNG funds also come from international investors in financial markets who acquire bonds issued by the companies. The external debt is senior debt meaning that debt service takes priority over the repayment of equity capital invested.

**Table 2: Debt Finance and Equity Shares in LNG Companies**

| *Company* | *Section* | *Debt* | *Equity Capital Shares* | | | | | |
|---|---|---|---|---|---|---|---|---|
| | | *Share* | *Gov.* | *Foreign Partners* | | | | |
| QatarGas | | | | Mobil | Total | Mitsui | Marubeni | |
| | Upstream | 0.55 | 0.65 | 0.2 | 0.1 | 0.025 | 0.025 | |
| | Downstream | 0.7 | 0.65 | 0.1 | 0.1 | 0.075 | 0.075 | |
| RasGas | | | | Mobil | Itochu | Nissho | | |
| | Upstream | 0.75 | 0.65 | 0.265 | 0.04 | 0.03 | | |
| | Downstream | 0.75 | 0.65 | 0.265 | 0.04 | 0.03 | | |
| OmanLNG | | | | Shell | Total | KOLNG | Mitsub/Mitsui. | Partex |
| | Upstream | 0 | 0 | 0.85 | 0.1 | | | 0.05 |
| | Downstream | 0.8 | 0.51 | 0.3 | 0.0554 | 0.05 | 0.0554 | |
| YemenLNG | | | | Total | Hunt | Exxon | Yukong | Hyundai |
| | Upstream | 0 | 0.6 | 0.133 | 0.133 | 0.133 | 0.133 | |
| | Downstream | 0.6 | 0.21 | 0.36 | 0.151 | 0.145 | 0.084 | 0.05 |

Note: All data from *Middle East Economic Survey, Cedigaz News Report, Gas Matters*, different years; and company sources. First column shows share of total investment costs financed from external sources, next columns show sharing of the remainder of total funds between equity partners.

External non-recourse creditors assume some of the risks of the project: their loans may not be repaid as expected if the project cash flow falls below debt service requirement. The perceived risk of the project determines the costs of external finance by determining the interest paid on the loans. Of course, a major international oil company is unlikely to let a high-profile project enter into bankruptcy proceedings because its own reputation would be at stake. The non-recourse basis of external finance is therefore largely symbolic, and lenders expect the major shareholders to bail out a project, if necessary. They therefore look closely at the project shareholders, and their creditworthiness. If they assume little real project risk, this is reflected in loan interest rates. Interest rates in all cases described here are specified with regard to the interbank lending rate LIBOR. The rates are therefore flexible and introduce an extra element of risk for the projects.

Bank loans usually cover a period of ten to twelve years with an initial grace period covering the production phase of the project, during which interest is due but no principal repayment is required. The exact terms of the loans are not well covered in the literature and we therefore assume this general pattern for all the four projects. In addition to bank loans

both RasGas and OmanLNG have issued significant amounts of bonds in the international bond markets. These reduce finance costs when looking at net present value figures because bonds have twelve to eighteen years maturity, although bond interest rates are slightly higher than bank loan rates.

## 3.2. Ownership Arrangements

### QatarGas

The first Qatari LNG venture is a partnership between the national QGPC with 65 per cent of the shares and the main foreign partners are Mobil and Total plus a smaller engagement of two Japanese companies, Mitsui and Marubeni. Upstream and downstream parts of the project are distinct: Mobil has a share of 20 per cent in the upstream, 10 per cent in the downstream, whereas Total has 10 per cent in both parts, and Mitsui and Marubeni each have 2.5 per cent in the upstream and 7.5 per cent in the downstream sections.

The upstream investment costs of $ 1.2 bn are 55 per cent debt financed. Mitsui and Marubeni provide $ 50 million. A commercial loan of $ 650 million and $ 500 million of equity contributions from the partners in QatarGas finance the remainder. The external financing is priced at 1 per cent over LIBOR, covering a period of ten years. QGPC partly finances its equity contribution with a commercial loan of $ 100 million, priced at 0.85 per cent over LIBOR, and running over ten years.

External debt for the liquefaction plant is $ 1.995 bn, of which $ 1.6 bn are financed by Japan EXIM bank at 0.9 per cent above LIBOR, and $ 400 million are provided by commercial banks at 1.65 per cent over LIBOR. Both loan tranches cover twelve years. The remaining $ 850 million are provided by the partners in QatarGas.

### RasGas

The company was set up between QGPC and Mobil with a 70:30 split in shares originally, but later the Japanese Itochu and Nissho Iwai joined with 4 per cent and 3 per cent of the shares, respectively, and the founding partners both relinquished 3.5 per cent. The two Japanese were taken on board to help financing and marketing the project.

Financing arrangements for RasGas are carried out *en bloc* for the upstream and downstream sides, but for the benefit of transparency we list the two sides separately. Total upstream investment is put at $ 835 million, whereas the downstream side requires initial investment of $ 1.7 bn, and external lenders provide a total of $ 1.55 bn. External funds are provided by a $1.2 bn corporate bond issue consisting of two tranches, the first providing $ 800 million priced at 2 per cent over LIBOR with maturity after seventeen years, and the second providing $ 400 million, at 1.5 per cent over LIBOR for ten years. $ 300 million are provided by export credit agencies (ECAs) at 0.9 per cent over LIBOR with a tenor of twelve years, and the remaining $ 450 million are covered by a commercial bank loan priced 0.95 per cent over LIBOR with a tenor of twelve years. For the purposes of this presentation it is assumed that the upstream side benefits from the lower interest costs, whereas the downstream section has to cover debt service for the bonds and the commercial bank finance.

**OmanLNG**

OmanLNG is a joint venture between the government of Oman (51 per cent), Shell (30 per cent), Total (5.54 per cent), KOLNG (5 per cent), Mitsubishi and Mitsui (2.77 per cent each), Partex (2 per cent), and Itochu (0.92 per cent). The upstream part of the project is entirely distinct from the downstream part. It is operated by Petroleum Development Oman (PDO), a joint venture of the government (60 per cent), Shell (34 per cent), Total (4 per cent), and Partex (2 per cent), but entirely owned by the government of Oman.

The upstream section requires capital investments of $ 1300 million and is financed from equity capital from only the foreign partners in PDO, with an agreement for capital and operating cost recovery over a minimum of five years starting in 2001 out of NGL and gas revenues. The agreement includes a provision for uplift, i.e. the cost recovery payments include interest of 12 per cent on the committed capital, giving PDO a guaranteed return of 12 per cent. Cost recovery is determined as 20 per cent of investment costs including uplift, plus operating and maintenance costs, up to a maximum of 50 per cent of total upstream revenues.

The arrangements in the upstream section therefore resemble a service contract, where the government is owner and PDO is a mere operator with a fixed remuneration contract, while cash flow net of cost recovery for the entire section accrues to the government. This increases greatly the risks faced by the government of Oman as compared with the profit-

sharing agreement in Qatar, but of course it also leaves a considerable upside potential for government cash flows.

The downstream section is 80 per cent debt financed, with $ 1 bn of the loans coming with guarantees from ECAs, a commercial facility of $ 300 million and bonds issued with a value of $ 500 million. We assume interest rates of 90 basis points (bps) above LIBOR for the ECA element of the loans, and 165 bps over LIBOR for the rest, with a tenor of twelve years for both, whereas the bonds are sold at 200 bps with eighteen years maturity.

**YemenLNG**

The Yemeni LNG project was established in 1995 after long negotiations resulting in a somewhat complicated ownership and operatorship structure, which partly evolved from the existing production-sharing agreements with three foreign companies and the unclear legal position concerning the ownership of the gas found under these agreements. The upstream operations are distinct from the downstream section and are carried out by an Operating Committee, which consists of the Yemeni state company GGC (60 per cent) and the Yemen Exploration and Production Company (YEPC, 40 per cent), which itself is a joint venture between Hunt, Exxon, and Yukong, and is the concession holder in the Marib fields dedicated to the project. After the year 2005, when the YEPC concession ends, a special operating company, Marib Services Company (MSC) with GGC 60 per cent, YEPC 30 per cent, and YemenLNG 10 per cent of interest, takes over the upstream part of the project. YEPC as the contractor recovers costs over eight years from gas and NGL sales. Any surplus cash flow benefits GGC and YEPC according to the 60:40 distribution of upstream shares.

The upstream arrangement in Yemen is a mix between the strict profit sharing in Qatar and the service contract in Oman. In Yemen, the upstream investment costs are provided by the foreign investors, as in Oman, but not in Qatar, where equity capital comes from all partners. Upstream revenues are shared through a profit-sharing arrangement in Qatar and Yemen, but not in Oman, where foreign partners receive a fixed return on investment.

YemenLNG is a joint venture with the government and Total as major shareholders (26 per cent and 36 per cent), and Total is overall operator and manager. So far, the following ownership structure has emerged:

| | |
|---|---|
| Total | 36.0 per cent |
| GGC | 21.0 per cent |
| Hunt | 15.1 per cent |
| Exxon | 14.5 per cent |
| Yukong | 8.4 per cent |
| Hyundai | 5.0 per cent |

Total also provides financing of 8 per cent of the 21 per cent GGC equity share as a loan over eight years after start-up. However, participation in the profits of the venture is not tied to participation in the investment. Instead, the government's profit share is determined on a sliding scale on the basis of the ratio of accumulated revenues to costs, starting at 25 per cent initially and increasing to a maximum of 90 per cent. Eligible costs include capital and financing of the GGC equity share, all investment outlays, but exclude interest payable on external debt. This sliding scale has the obvious consequence that the minimum price guarantee given by the company to the GGC becomes a heavy liability for the company in later years.

Downstream investment is $ 1.4 bn, with 60 per cent coming from external sources, half of it with ECA guarantees at 90 bps above LIBOR, the other from commercial bank sources at 165 bps above LIBOR. This leaves an equity contribution for the GGC of $ 208 million, of which roughly one-third is provided by Total as an eight-year loan at Total's borrowing rate, which we assume is 90 bps above LIBOR.

## 3.3. Concluding Comments

The agreements underlying the formation of LNG joint-venture companies seem to be unique in each case discussed here. The factors influencing the design of a joint-venture agreement are the financial and technological strength of the potential partners and the legal situation in the resource producing country. National laws usually require the participation of the national oil company in any resource producing venture, and require the new joint-venture company to pay royalties and taxes which alters the expected cash flows of the projects. The national oil companies differ greatly in skills and sizes.

Also, at least in the case of Yemen, production-sharing agreements with international companies existed prior to the conception of the LNG project, which meant that these companies had to be included somehow. Ultimately, all the parts of the agreements are open

for negotiation, but especially royalties and production shares might be defined by national laws. If this is the case a change might involve a lengthy legislation process. Delaying legal battles can result from poorly specified property rights, as in Yemen where it was initially unclear whether the concession holders had ownership of the natural gas.

Of high importance for the viability of the projects is the extent to which the LNG venture benefits from the sales of condensates or NGL which are valuable by-products of the gas. The distinction between upstream and downstream sections of the projects is therefore largely artificial, because a highly profitable extraction of liquids can subsidise the downstream liquefaction of the gas with lower profitability. On the other hand, a mere stripping of the gas stream and re-injection of dry gas might not find the approval of national governments. The extent of cross-subsidisation of upstream and downstream sections decides about the overall profitability of the project.

# 4. MEAN CASH FLOW CALCULATIONS

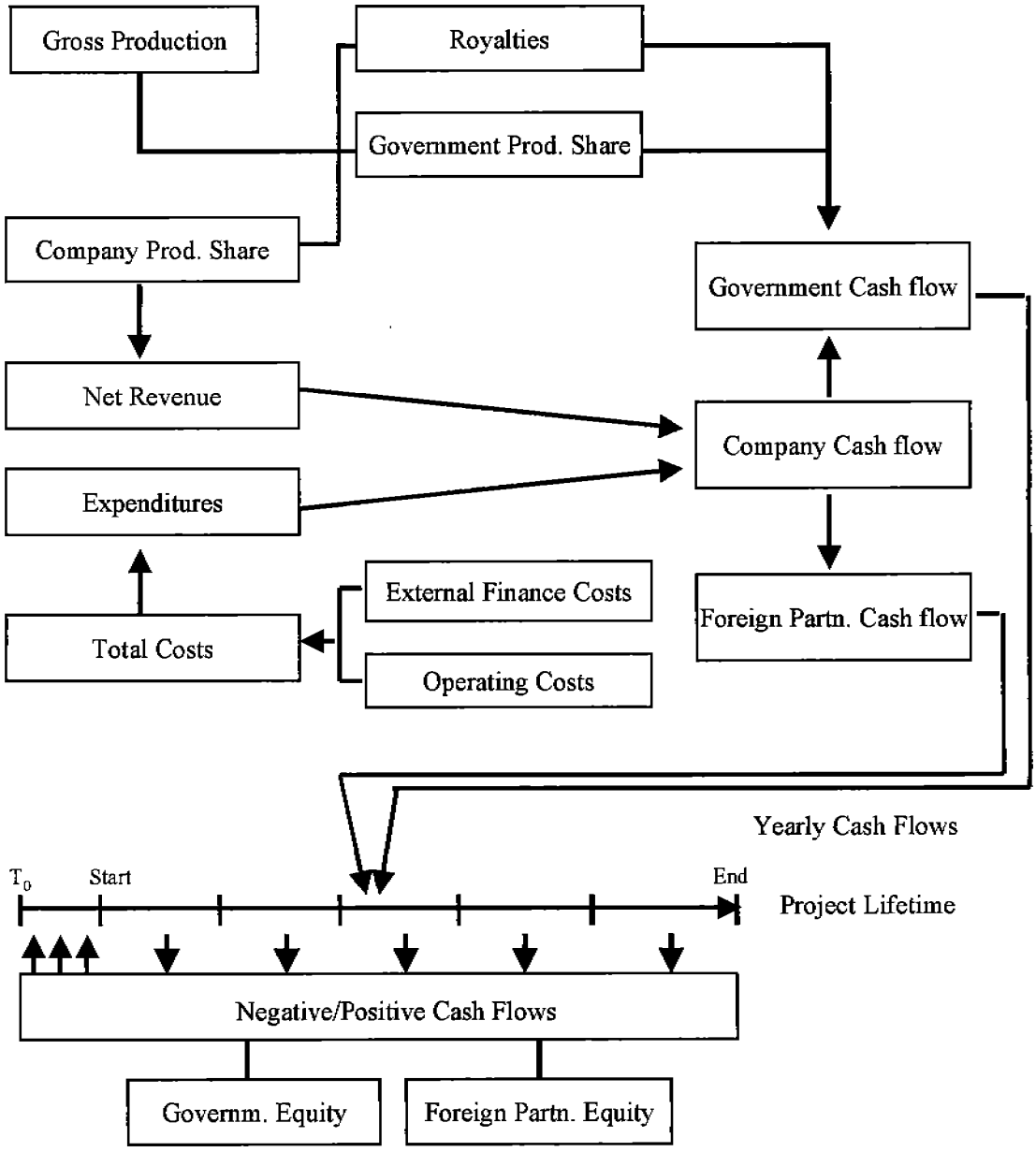
## 4.1. General Framework and Assumptions

With the benchmark data provided in Sections 2 and 3 we can now turn to the expected revenues and costs of the projects, and calculate cash flows arising from their operation in order to evaluate the economics of the LNG ventures in the Middle East. The simulations in this section are based on deterministic price and cost assumptions for oil prices, benchmark interest rates, and operating costs, while in Section 5 cash flows are calculated using Monte Carlo simulation techniques, i.e. prices and costs are sampled from probability distributions in repeated cash flow calculations to obtain ranges of outcomes.

Figure 2 shows schematically the calculation of yearly cash flows and the project life-cycle on the bottom. Gross production of lean gas, NGL and LNG is found on the top left corner of the diagram. From this moving to the right, royalties and government production shares are deducted and the rest, the company production share, constitutes net LNG company production. This is sold to bring in revenues. On the cost side external finance costs, i.e. repayment of principal and interest costs, and operating costs make up total costs (transport costs are external to the projects). These are set against revenues, and any surplus or deficit, shown as company cash flow, is shared between the two accounts distinguished: the government account on the one hand, which receives royalties and production shares deducted from gross production in addition, and the foreign partner account, which receives some upstream production shares in addition in the cases of Oman and Yemen.

Yearly cash flows are discounted and summed to give net present values, represented by the project lifetime graph on the bottom of the diagram. Equity capital contributions from the government and the foreign partners are expenditures (negative cash flows) in the construction phase of the projects, which covers the initial three years. Yearly cash flows after start-up of production (positive cash flows) are shared between governments and foreign partners according to profit shares and are equity repayment. The discounted balance of capital expenditure in the beginning and repayment over the lifetime of the project is the net present value of cash flows.

**Figure 2: Cash Flow Calculations**




The true project economics depend on country and project specific factors, timing, and contractual details which are usually not available in the public domain. In order to make meaningful comparisons, some simplifying assumptions have to be made here. These are held as realistic as possible, but it should be kept in mind that for the purposes of the analysis consistency and comparability are most important.

The underlying assumptions used in all cash flow simulations in Sections 4 and 5 are shown in Box 1. The calculations use an inflation rate of 3 per cent per year, and a project lifetime of

**Box 1: Assumptions for Cash Flow Calculations**

- total capital investment and transport costs are assumed to be known with certainty;
- calculations are carried out in nominal terms and an adjustment for inflation is made which increases prices by 3 per cent per year;
- for all projects we assume a construction period of three years, and all capital is invested during those three years and revenues start flowing only in the fourth year;
- project lifetime including construction period is 28 years, i.e. a cover period of LNG contracts of 25 years;
- during the initial four years of commercial operation after the construction period has ended, the start-up phase of the projects, output increases in steps to 50, 70, 85, and 90 per cent of design capacity;
- external loans start at the beginning of the construction period and come with a grace period over three years such that no principal payments are due during construction;
- comparison between the projects does not take the different start dates into consideration, all calculations discount payments to project start date at $T_0$;
- no provisions are made for capital depreciation and corporate taxes, i.e. we calculate gross, pre-tax cash flows;
- operating costs are $ 0.24 per mBtu in the upstream section, $ 0.41 per mBtu in the downstream section;
- transport (c.i.f.) costs are $ 1.50 per barrel of crude oil, $ 1.10 per mBtu for LNG from the Gulf to Japan;
- mean oil price is $ 16 per barrel of Arabian Light, LIBOR interest rate is 6.3 per cent;
- the discount rate used is 12 per cent, since a 3 per cent inflation rate is included in payments this translates into a real rate of 9 per cent.

28 years. The project lifetime consists of a construction phase of three years, and a start-up phase of four years. During the start-up phase production increases step-wise to reach design capacity.[5]

Cash flows from LNG ventures arise from the need to expend investment and operating costs, and from revenues for the sales of raw gas from the upstream to the downstream side, liquids, and LNG. Fiscal regimes and ownership structures decide how costs and revenues are shared between the partners involved in the projects. Two different accounts are

[5] This is a conservative approach. Project technology is mature and start-up phases can be held very short on the production side. Start-up phases are often included in the sales contracts because of marketing constraints on the

distinguished: (i) the government account which includes the national oil company account, and (ii) the foreign shareholder account. Three product prices are needed for the calculations:

- The price at which raw gas is sold to the liquefaction plant. This is fixed in nominal terms in all of the four ventures by agreement.
- The price at which NGL are sold in the international market. This is assumed to be equal to the price of crude oil.[6]
- The LNG price. The calculations use the Qatari and Omani price formulas introduced in Section 2.3 and assume the Omani formula applies to RasGas, OmanLNG, and YemenLNG.

As mentioned above the sales price formula for LNG from QatarGas contains a minimum price of $ 3.60 per mBtu for landed LNG. This is equal to a crude oil price of about $ 17 per barrel. In the case of Yemen, the foreign partners have agreed to guarantee a minimum cash flow to the government of Yemen, which is equal to the downstream cash flow share it would receive at an LNG price of $ 2 per mBtu on a f.o.b. basis. Both minimum prices grow at 3 per cent per year just like the oil and therefore the NGL and LNG prices to account for general inflation.

In the sections below we present two sets of data: yearly cash flows evaluated directly, and cash flows discounted at 12 per cent and summed to give net present values (NPV) for the projects at $T_0$ before construction starts. Yearly cash flows are presented to show the different payments into and out of the accounts distinguished. Yearly cash flows are important for budget and contingency planning, and we will come back to them in Section 5.5. The net present value calculations show the size of different components of the projects, especially the impact of external finance on enhancing project cash flows.

## 4.2. Yearly Cash Flow Components

This section shows cash flow components for the four LNG projects calculated for an example year, the eighth year of operation which is the first year of full capacity operation. The four parts of Table 3 present the payments going into and flowing out of the different

buyer side. During such sales contract start-up phases, LNG projects try to market extra volumes on a spot basis if transport is available, with potentially large extra revenues. These are excluded from the analyses in this paper.

[6] NGL sell internationally at different prices and the spread between the price of crude oil and NGL fluctuates. NGL serve a niche market and currently it seems that they do not command a premium over crude. Because of ever increasing NGL production due to a relatively high growth rate of natural gas production it is unlikely that NGL prices will increase against the crude oil price in the near future.

accounts. The first part shows the components for the QatarGas project, starting with costs in the first four rows, where upstream costs are shown in the first data column and downstream costs in the second data column. These two columns show company cash flows, whereas the third and fourth columns show payments into the government and foreign partner accounts.

In the first two columns, cost elements are repayment of external capital, interest payments on loan capital, operating expenditure in the third data row, and finally the costs of gas sold from the upstream side to the downstream liquefaction plant. Total upstream costs in QatarGas are $ -200 million, downstream costs are shown as $ -597 million.

Data rows 6 to 12 in the first two columns show revenue data. Revenues from gas sales to the liquefaction plant are shown as zero in the upstream column, because the government receives the entire gas sales revenues as government production share, shown in the government column. LNG sales amount to $ 958 million. This is about 2.5 times as much as the sales value of NGL, which is the sum of NGL revenue shown in the upstream column, royalties, and government production share going into the government account in the rows below. The table then shows net company cash flows, i.e. total company revenues minus costs. Upstream cash flows in QatarGas are much below downstream cash flows, $ 46 million as compared with $ 361 million. Company cash flows are reduced by royalties and government production shares shown in the third column to be worth almost $ 300 million. This means total upstream cash flow is about the same as the downstream cash flow.

Net company cash flows are shared between government and foreign partners according to the profit shares shown. Profits in the case of QatarGas are shared 65:35 in favour of the Qatari national oil company. In the third row from the bottom of the table the profit shares are shown, payments into government and foreign partner accounts in the last-but-one row, the last row shows total cash flows in the government and foreign partner accounts, where the government receives royalties, production shares, and a profit share of the net cash flows, whereas the foreign partners receive only profit shares. The government receives a total of $ 539 million, and the foreign partners $ 143 million in year 8 of operations.

The structure of payments is the same in the second panel of Table 3, showing the RasGas payments. All payments are obviously smaller because of the smaller production volume of RasGas. The structure of cash flows in OmanLNG and YemenLNG is slightly different as seen in the two following panels of Table 3 because of the different arrangements in the upstream parts of the projects. In both joint ventures the upstream sections are financed entirely by equity capital, with government oil company involvement in Oman, but without in the case of Yemen.

**Table 3: Yearly Cash Flow Components (in $ millions)**

| QatarGas | | LNG Company | | Shareholder Accounts | |
|---|---|---|---|---|---|
| | | *Upstream* | *Downstream* | *Governm.* | *For. Partn.* |
| **Costs** | | | | | |
| | Repaym. | -94 | -218 | | |
| | Interest | -14 | -64 | | |
| | Oper.Costs | -92 | -159 | | |
| | Gas Costs | | -157 | | |
| | **Total** | -200 | -597 | | |
| **Revenues** | | | | | |
| Gas, LNG | Sales Reven. | | 958 | | |
| | Royalty | | | | |
| | Prod.Share | | | 157 | |
| NGL | Sales Reven. | 246 | | | |
| | Royalty | | | 44 | |
| | Prod.Share | | | 74 | |
| | **Total** | 246 | 958 | 274 | |
| **Revenues minus Costs** | | 46 | 361 | | |
| **Profit Shares Gov. (F.P.)** | | 0.65 (0.35) | 0.65 (0.35) | | |
| **Profits** | | | | 265 | 143 |
| **Cash Flows** | | | | 539 | 143 |
| **RasGas** | | | | | |
| **Costs** | | | | | |
| | Repaym. | -70 | -106 | | |
| | Interest | -20 | -58 | | |
| | Oper.Costs | -73 | -127 | | |
| | Gas Costs | | -124 | | |
| | **Total** | -162 | -415 | | |
| **Revenues** | | | | | |
| Gas, LNG | Sales Reven. | | 822 | | |
| | Royalty | | | | |
| | Prod.Share | | | 124 | |
| NGL | Sales Reven. | 204 | | | |
| | Royalty | | | 26 | |
| | Prod.Share | | | 61 | |
| | **Total** | 204 | 822 | 211 | |
| **Revenues minus Costs** | | 41 | 407 | | |
| **Profit Shares Gov. (F.P.)** | | 0.65 (0.35) | 0.65 (0.35) | | |
| **Profits** | | | | 291 | 157 |
| **Cash Flows** | | | | 502 | 157 |

| **OmanLNG** | | *LNG Company* | | *Shareholder Accounts* | |
|---|---|---|---|---|---|
| | | *Upstream* | *Downstream* | *Governm.* | *For. Partn.* |
| **Costs** | | | | | |
| | Repaym. | -220 | -144 | 132 | 88 |
| | Interest | | -54 | | |
| | Oper.Costs | -104 | -175 | | |
| | Gas Costs | | -111 | | |
| | **Total** | -325 | -483 | | |
| **Revenues** | | | | | |
| Gas, LNG | Sales Reven. | 111 | 1118 | | |
| | Royalty | | | | |
| | Prod.Share | | | | |
| NGL | Sales Reven. | 574 | | | |
| | Royalty | | | | |
| | Prod.Share | | | | |
| | **Total** | 685 | 1118 | 132 | 88 |
| **Revenues minus Costs** | | 360 | 635 | | |
| **Profit Shares Gov. (F. P.)** | | 1 (0) | 0.51 (0.49) | | |
| **Profits** | | | | 683 | 311 |
| **Cash Flows** | | | | 816 | 399 |
| **Yemen LNG** | | | | | |
| **Costs** | | | | | |
| | Repaym. | -36 | -127 | | 36 |
| | Interest | | -37 | | |
| | Oper.Costs | -95 | -164 | | |
| | Gas Costs | | -137 | | |
| | **Total** | -130 | -465 | | |
| **Revenues** | | | | | |
| Gas, LNG | Sales Reven. | 137 | 1041 | | |
| | Royalty | | | 21 | |
| | Prod.Share | | | | |
| NGL | Sales Reven. | 218 | | | |
| | Royalty | | | 73 | |
| | Prod.Share | | | | |
| | **Total** | 355 | 1041 | 94 | 36 |
| **Revenues minus Costs** | | 225 | 576 | | |
| **Profit Shares Gov. (F.P.)** | | 0.6 (0.4) | 0.21 (0.79) | | |
| **Profits** | | | | 256 | 545 |
| **Cash Flows** | | | | 350 | 581 |

Note: Cash flow components in year 8 of project operation in money-of-the-day $ millions; for explanations see text.

Upstream capital repayment is therefore shown as a cost to the upstream section of the LNG company in the first data column, and as a benefit in the government and/or foreign partner accounts in the last two columns.

Upstream cost recovery in Oman in year 8 of the project lifetime is a cost of $ -220 million to the upstream business, and is shared between the partners in PDO, which means the government receives 60 per cent or $ 132 million, and the foreign partners the remaining 40 per cent. In the case of YemenLNG, cost recovery amounts to $ 36 million, but here the government does not receive a share because it is not a partner in YEPC.

On the other hand, gas sales from the upstream to the downstream sections show as upstream company revenues in the Omani and Yemeni projects. Gas sales are worth $ 111 million in Oman, and $ 137 million in Yemen. In Oman, no royalties are due on gas or NGL, with NGL revenues of $ 574 million in the company account, whereas YemenLNG pays a 25 per cent royalty on liquids which goes directly to the government account. The ratio between government and foreign partner cash flows is almost 4:1 in all except the Yemeni project where foreign partner cash flow is higher than government cash flow because of the low government profit share.

In the next section the study presents the details shown here for the whole lifetime of the project in terms of net present values of cash flow components.

## 4.3. Net Present Values of Cash Flow Components

Taking cash flow components as shown in the last section for each year over the lifetime of the projects, discounting and adding gives the net present values of cash flow components within the lifetime. These NPVs are shown in Table 4 and Figure 3 below. The four parts of the figure show the NPVs of cash flow components from the projects, disregarding distribution over different accounts. This section discusses the importance of different components.

The first column in each graph shows NPV of gross revenues, i.e. revenues from sales of total gas, NGL and LNG production disregarding royalties and different production shares. The second column shows NPV of costs, where costs consist of gas purchases from the upstream section, repayment and interest payments for loans (shown as external capital costs

in Table 4), operating costs, equity capital and return on equity (shown as equity expenditure in the table).

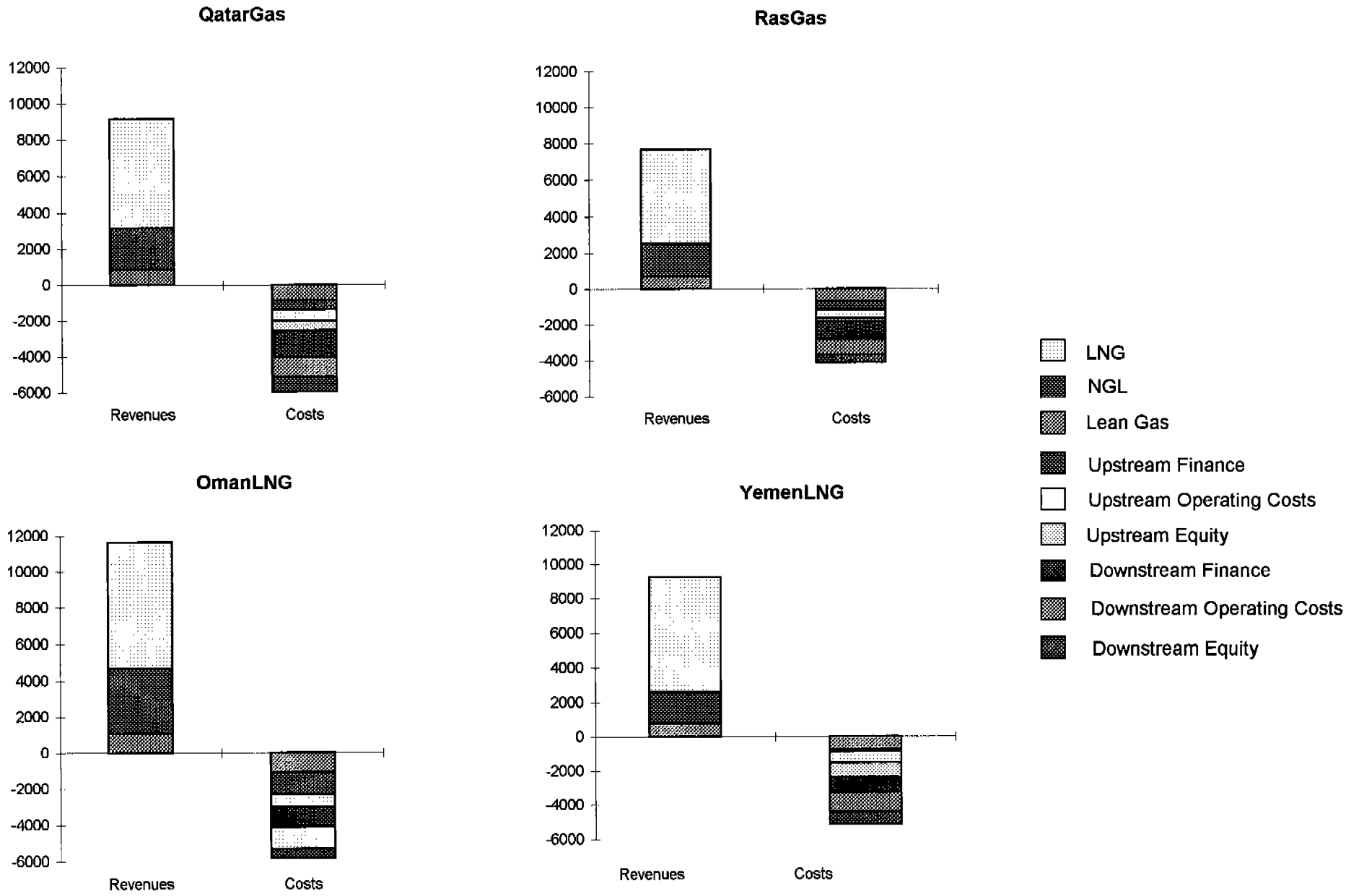
The first graph shows cash flow components for QatarGas. As shown in the first column in Table 4, the project is scheduled to produce a NPV of $ 5996 million worth of LNG over its lifetime, $ 2273 million of NGL, and the sales of lean gas to the liquefaction plant have a NPV of $ 877 million. Natural gas production in the form of lean gas and LNG is therefore worth almost three times as much as NGL production.

In the next graph of Figure 3 showing cash flow components for RasGas the dominance of LNG production over NGL is about the same as in QatarGas, although it is not protected by minimum prices, because of the higher sales price formula. RasGas sells $ 5146 million worth of LNG, $ 1818 million of NGL, and lean gas sales amount to $ 694 million. The RasGas LNG production volume is about 20 per cent smaller than the volume planned for QatarGas. Gas is worth three times as much as NGL production. In all four cases NGL revenues constitute the bulk of total upstream revenues, roughly three times as high as revenues from lean gas sales to the liquefaction plants.

Gas sales appear twice in each column in Table 4, once as revenues to the upstream sections, and again as costs to the downstream sections. Gas payments are therefore a transfer between upstream and downstream, and affect government or foreign partner cash flows only if revenue sharing is different in the two sections. This is the case in all of the projects, and gas payments are therefore part of government taxation of the LNG ventures.

The last-but-one row in Table 4 shows the net present values of gross project cash flows. The NPV of QatarGas cash flows is lower than that of the other three projects because of the lower LNG sales price. The NPV of RasGas cash flows is lower than of OmanLNG and YemenLNG because production volumes are much below other projects. The difference between gross NPVs of cash flows of Oman with $ 5931 million and Yemen with $ 4052 million are due to the relatively low level of NGL production and higher financing costs in the latter project. In the two Qatari ventures the NGL sales are the only source of revenue for the upstream investors. It can safely be argued that the upstream sections of the LNG ventures have a vital interest in NGL production.

**Figure 3: Net Present Values of Cash Flow Components**




Note: Vertical axes show NPVs of cash flow components in $ millions.

In Table 4, external financing costs, i.e. repayment of loans and interest costs, are distinguished from equity capital expenditures. The latter are entered as the part of investment costs which are not debt financed. Since all data in the table are expressed in net present values with a discount rate of 12 per cent, entering the original equity capital contributions means equity capital costs include return on equity of 12 per cent.

**Table 4: Summary of NPVs of Gross Production and Costs**

| | *QatarGas* | *RasGas* | *OmanLNG* | *YemenLNG* |
|---|---|---|---|---|
| **Revenues** | | | | |
| Gas | 877 | 694 | 1063 | 766 |
| NGL | 2273 | 1818 | 3592 | 1818 |
| LNG | 5996 | 5146 | 6996 | 6647 |
| **Costs** | | | | |
| Gas Costs | 877 | 694 | 1063 | 766 |
| Ext. Cap. Costs Upstream | 513 | 474 | 1270 | 124 |
| Operating Costs Upstream | 633 | 501 | 721 | 653 |
| Equity Exp. Upstream | 540 | 209 | 0 | 876 |
| Ext. Cap. Costs Downstream | 1492 | 975 | 1098 | 868 |
| Operating Costs Downstream | 1096 | 877 | 1206 | 1133 |
| Equity Exp. Downstream | 840 | 425 | 360 | 760 |
| **Gross Project Cash Flow** | 3155 | 3503 | 5931 | 4052 |
| Capital Cost Savings (gearing) | -615 | -452 | -171 | -272 |

Note: Net present values of cash flow components in $ millions.

Upstream capital investment in Oman is covered by the PDO partners and is repaid with 12 per cent return, so appears in Table 4 as external capital costs. In Yemen, upstream investment costs are covered by the YEPC shareholders but are repaid without uplift. The YEPC shareholders are also YemenLNG shareholders, and return on equity has to come from project cash flows. Therefore external capital cost for YemenLNG is the net present value of cost recovery, shown as $ 124 million in Table 4. In addition, $ 876 million are entered as equity capital costs to cover upstream investment requirements of $ 1 bn.

The last row in Table 4 shows the cost savings achieved through debt financing part of the investment costs. The figures are obtained by adding external finance costs and equity capital expenditures in the table, and subtracting the sum from the total investment requirements. The cost savings arise from the difference between interest costs for external loans, which are between 7 and 8 per cent per year, and the return on equity of 12 per cent as assumed by using a discount rate of 12 per cent in the NPV calculations. Gross project cash flows and cost savings through gearing in Table 4 are used in Section 6 to determine unit costs of gas with or without gearing.

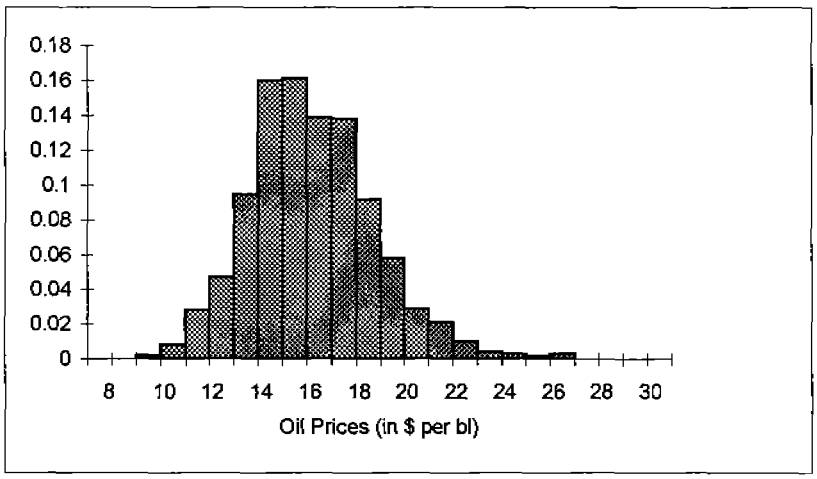
In all the projects, LNG revenues are sufficient to cover all costs (gas revenues are equal to gas costs) so in principle the government off-take in the upstream section could be 100 per cent for both gas and NGL revenues, and cash flows downstream would be enough to produce a net return on foreign partner equity capital invested in both sections of 12 per cent. This shows a high profitability of the LNG business given the right oil prices (here $ 16 per barrel), where the investment is fully justified on grounds of gas alone, and in addition produces a NPV of NGL revenues of $ 2–3.5 bn. Looking at the upstream section on its own, NGL revenues are sufficient to cover upstream costs, and gas revenues are not needed if government upstream off-take is not too high.

# 5. MONTE CARLO SIMULATIONS OF CASH FLOWS

## 5.1. Assumptions and Indicators

Cash flows simulated in Section 4 are based on the assumption of fixed oil prices, interest rates and operating costs. In this section, prices and costs are generated randomly to simulate the probabilistic nature of the LNG business. By varying price and cost inputs into the cash flow calculations, the sensitivity of results to price and cost changes can be shown. Instead of merely showing some arbitrarily chosen high and low estimates, we simulate a range of prices and costs. This allows a more detailed sensitivity analysis, and statements about the probability of outcomes with the assessment of risks using statistical tools.

**Figure 4: Distribution of Oil Prices Used in Monte Carlo Simulations**




Note: The vertical axis shows the relative frequencies of the oil prices (in $ per barrel) shown in the horizontal axis.

**Probability Distributions**

Calculations are repeated 1000 times for each of the ventures to produce Monte Carlo simulations. For each calculation 'run', prices and costs are randomly generated from probability distributions. Annex 1 discusses the probability distributions chosen in detail. As an example, Figure 4 shows the shape of the distribution we have used for the generation of oil prices in the form of a histogram. The mean of the oil price is $ 16 per barrel, oil prices are lognormally distributed with an average negative deviation from the mean of $ 2 per barrel. As discussed in Annex 1, LIBOR interest rates underlying financing costs for the projects are assumed to be normally distributed with a mean of 6.3 per cent and a standard deviation of 2, and operating costs are sampled from lognormal distributions which return mean values as shown in Section 2 and have standard deviations equal to 20 per cent of the mean.

**Profitability and Risk Indicators**

In order to evaluate risks and risk sharing using the outcomes of the Monte Carlo simulations we need indicators of returns and risks. Annex 2 shows how the mean of the net present value (NPV) of cash flows is used to calculate a Profitability Indicator (PI), and how the range of NPVs of cash flows obtained from the Monte Carlo simulations is used to derive a Risk Indicator (RI).

In short, the PIs show factors of equity investment recovery. A PI of 1 shows that the NPV of cash flows is zero, i.e. cash flows are sufficient to recover equity investment over the lifetime of the project with a discount rate of 12 per cent. This is equivalent to saying that the internal rate of return on equity is 12 per cent. Any higher value for PI shows returns in excess of equity investment recovery, or internal rates of return greater than 12 per cent.

The determination and interpretation of RIs is slightly more complex. First, lower range PIs are calculated by using the probability distributions of NPVs of cash flows. Lower range PIs use lower range NPVs instead of mean NPVs of cash flows and put them in relation to equity investment. Lower range NPVs are mean NPVs minus the average deviation from the mean. Intuitively, the mean PI is the average outcome, the lower range PI is the average bad outcome.

The differences between mean PIs and lower range PIs are divided by the mean PIs and shown in percentage terms to give the Risk Indicator. A RI of 50 per cent shows that the

lower range profitability of a project is half of the mean profitability, a value of 100 per cent means that the lower range PI is zero, i.e. that no equity capital is paid back by the project in the lower range case.

Profitability and Risk Indicators are used to show the effects of project finance, fiscal regimes, and ownership structures on returns and risks. Firstly, Monte Carlo simulations are carried out for gross project NPVs of cash flows without regard to fiscal regimes and ownership structures, as in the deterministic cash flow calculations shown in Table 4 in Section 4. These simulations show *a priori* profitability and risks, before external finance, royalties, production sharing, and profit sharing are applied. Secondly, these *a priori* simulations are carried out taking into consideration the reduction of total capital costs achieved through external finance. Thirdly, actual PIs and RIs for government and foreign partner accounts are determined.

Comparisons of *a priori* profitabilities and risks with and without gearing show the extent to which external finance has achieved an increase in profitability, and what increase in risk has to be accepted for it in return. Comparison between *a priori* and actual PIs and RIs indicate how well investors have done in increasing returns and mitigating risks through fiscal regimes and ownership structures.

**Lender Risks**

In the project agreements, external financing is obtained on a non-recourse basis, so in principle the equity partners do not guarantee debt repayment. A serious shortfall in revenues would lead to bankruptcy, and some debt rescheduling and redistribution of equity shares could be expected in response. The lenders therefore carry some of the project risk.

In contrast, in the calculations used for this paper external capital is senior debt in the sense that capital costs are covered by the equity shareholders if company cash flows fall below debt service requirements. Therefore bankruptcy is ruled out in the calculations shown here and lenders do not carry any risk which is instead shouldered by the equity partners. However, this does not lead to serious distortions of the results because the probability of cash flows below debt service requirements is extremely low. In the real world one could expect a renegotiation of joint-venture agreements and maybe even sales contracts if oil prices turned out to fall to such extremely low levels for an extended period. It should be kept in mind that a re-negotiation of contracts serves to mitigate risks for lenders and investors when evaluating

the uncertainty of cash flows. In addition it is unlikely that international oil companies would allow a project to file bankruptcy because of the implications for their reputation, and therefore the non-recourse designation of external financing is rather symbolic. Lender risks are therefore rather small. Re-negotiation and face-saving bailing out of projects are political processes which cannot be modelled in these simple calculations.

Section 5.2 discusses the ranges of yearly cash flows resulting from the simulations. Sections 5.3 and 5.4 discuss the shapes of the probability distributions obtained from the Monte Carlo simulations. Section 5.5 compares returns on investment from the four LNG projects and the riskiness of these returns using the indicators introduced above and defined in Annex 2.

## 5.2. Yearly Cash Flow Simulations

This section takes another look at yearly cash flows, which were already discussed in Section 4. Here we present yearly cash flows over the lifetime of the projects as obtained from the Monte Carlo simulations, looking both at mean levels and at the probabilistic range of outcomes. Apart from the overall profitability in terms of the internal rate of return or positive NPV of cash flows, decision makers will be interested in the yearly cash flows coming from the project for operational budgeting.

Figure 5 shows therefore mean yearly cash flows and their variability for the government and the foreign partner accounts. In each graph in the figure, cash flows in $ millions are marked along the left-hand side vertical axis, and the years of the project cycle on the horizontal axis. The figure shows the initial equity investment as negative cash flows, and the build-up of sales over the initial four years. All cash flows in the figure are in real terms, i.e. the nominal flows from the cash flow calculations have been discounted by the 3 per cent inflation rate which applies to all costs and prices in the cash flow model used throughout this paper.

Variability of these cash flows is shown by the spread between the mean cash flow series and the upper and lower range series, which are derived as mean plus average positive deviation (APD) or minus average negative deviation (AND).

Table 5 summarises the data underlying the graphs by showing the average mean yearly cash flows, determined over mean cash flows between year 8 and 28 of the project cycle. Also shown are upper and lower range figures.

**QatarGas**

It is clear from the previous discussions that the variability or risk of cash flows is small in the case of QatarGas, because of the floor under LNG sales prices which is higher than the equivalent mean oil price used in the simulations. In the first two charts in Figure 5, QatarGas cash flows are shown, the left hand upper chart for the government account, the right hand chart for the foreign partners. Mean yearly cash flows in the government account increase from $ 450 million in the fifth year of commercial operation, to $ 649 million in the middle of the project cycle and $ 631 million in the year the joint-venture agreement and LNG sales contract end. Except for the early years with low production and heavy debt burden the risk of yearly cash flows is very low.

Cash flows in the foreign partner account are equally reliable, even more than the government receipts because the foreign partners receive less of the more uncertain proceeds of NGL sales than the government side. Cash flows shown in Figure 5 increase from $ 122 million at the beginning of operation to $ 222 million at the end of the contract period. Clearly visible in the graphs is the pay-back periods for external finance. Part of the loans have a maturity of ten years, part twelve years, after which both government and foreign partner cash flows increase. During the investment period interest payments are due but no principal repayment, therefore the initial negative cash flows increase year-by-year.

**RasGas**

The next pair of charts in Figure 5 is the result of the simulation of RasGas cash flows. Government cash flows increase from $ 413 million in the first year of full capacity operation, to $ 530 million at the end of the contract period. The average negative deviation in this year is about $ 80 million. The foreign partners expect mean cash flows increasing from $ 121 to $ 181 million, with an average negative deviation of about $ 40 million. Again the pay-back periods for external finance can be read from the graphs, with bank loans expiring after twelve years, and bonds after an average period of fourteen years.

**Figure 5: Yearly Cash Flows**

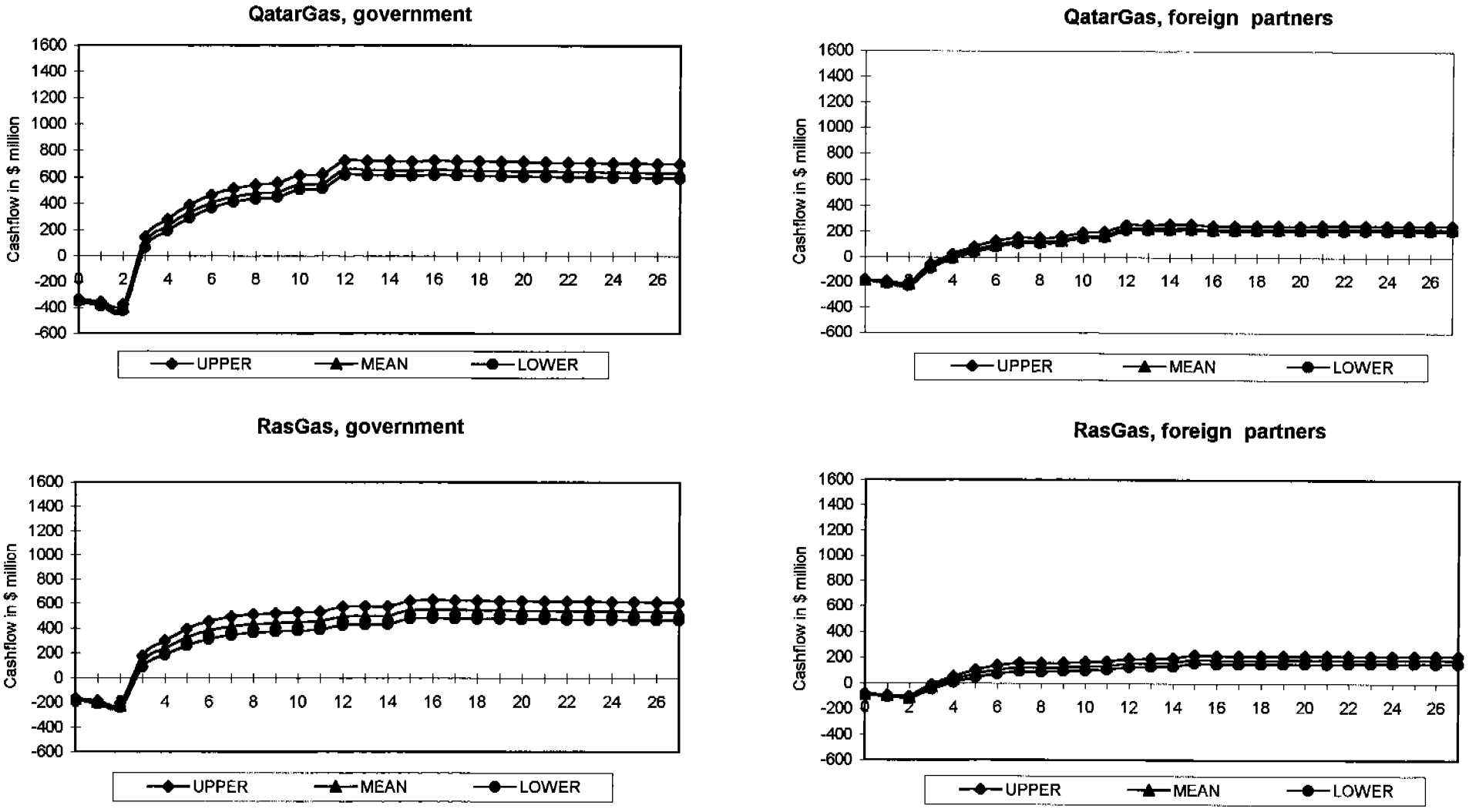
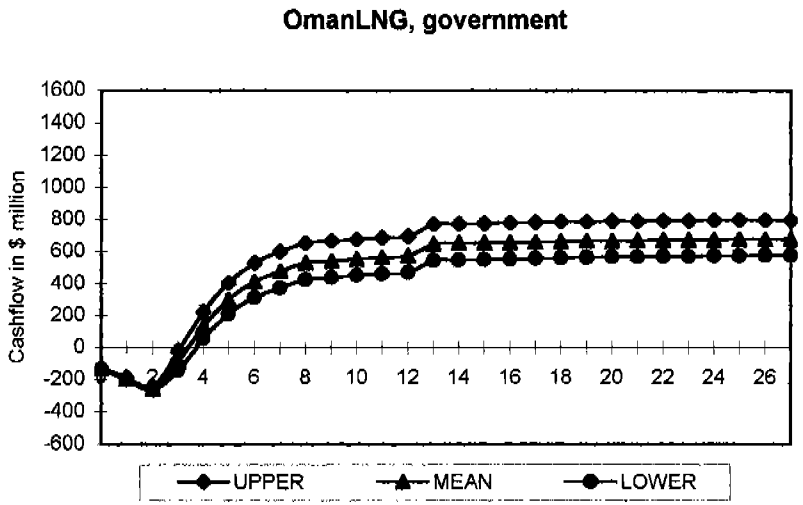
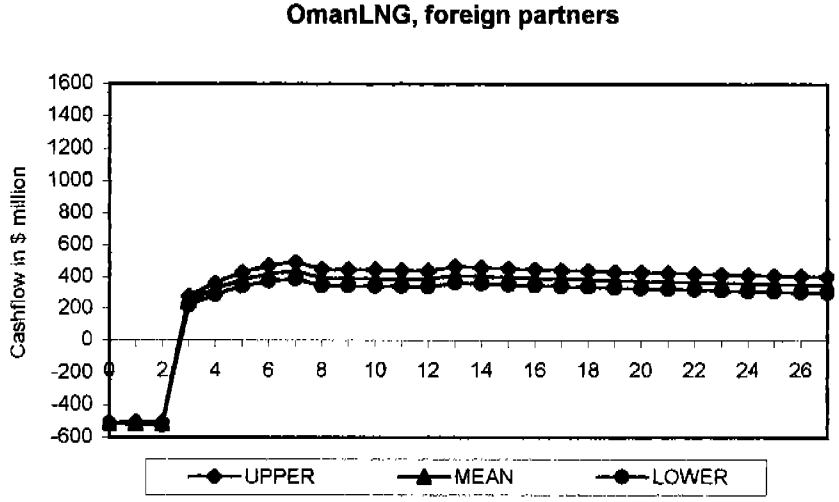
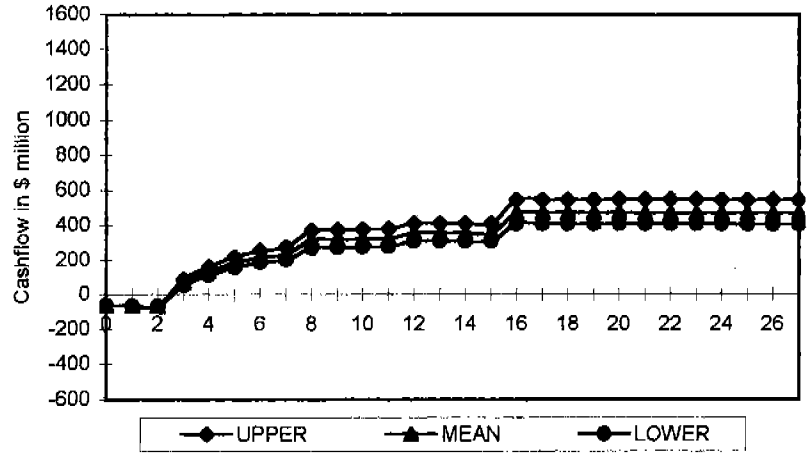
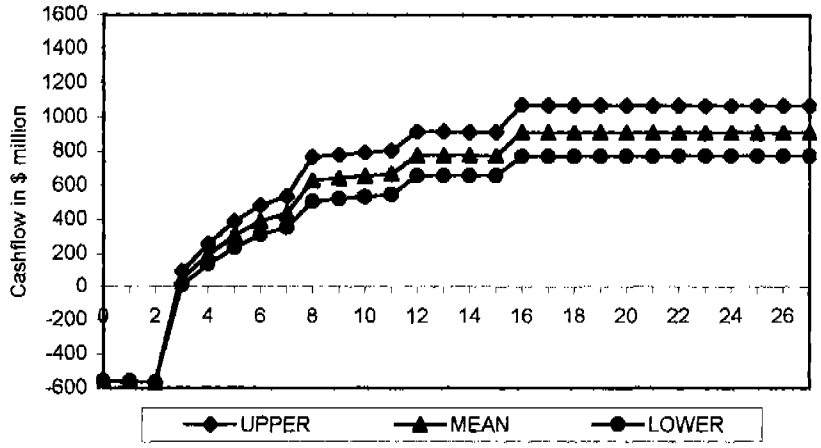


**Figure 5: Yearly Cash Flows (continued)**




Note: Horizontal axes show years of project cycle, vertical axes show cash flows in real $ millions.

**OmanLNG**

The yearly cash flows for OmanLNG are shown first on the second page of Figure 5. It is obvious when comparing government and foreign partner cash flows that the capital investment by the government is very low. The foreign partners spend about $ 500 million per year during the construction period, which includes interest on outstanding capital. Government cash flows reach $ 477 million after build-up, and $ 680 million at the end of the contract period.

The foreign partner account shows cash flows with an average of $ 421 million, with later years showing lower cash flows than earlier years because the upstream cost recovery ends after about 14 years and foreign partners do not share in upstream profits. Government cash flows strongly increase after debt repayment and cost recovery end as shown by the obvious climb in the government account figures after the twelfth year. The probability of negative cash flows is negligible for both accounts.

**YemenLNG**

The yearly cash flows for the Yemeni venture show the same pattern of high risk for the foreign partner account as the NPV simulations, but upper range figures are very high, i.e. they show considerable upside potential. The cash flow series in the last two charts in Figure 5 also show that the government has very little equity participation which is the main reason for the high NPV of cash flows.

Government cash flows increase from $ 238 million after the build-up period to $ 470 million at the end of the contract period. Foreign partner cash flows increase at the same time from $ 439 million to $ 913 million. This is the only project in the comparison where foreign partner cash flows exceed government cash flows in later years of the project cycle. After fifteen years of operation when debt repayment and cost recovery have ended cash flows increase significantly. The high upward potential for foreign partner cash flows is clearly visible in the chart. The upper range cash flows, determined by adding the average positive deviation to the mean, show an average amount of $ 1004 million over the commercial operation period. Nevertheless, foreign partner risk is high with an average negative deviation of 18 per cent of the mean.

**Table 5: Summary of Yearly Cash Flows**

| | | *QatarGas* | *RasGas* | *OmanLNG* | *YemenLNG* |
|---|---|---|---|---|---|
| Governm. | Mean | 646 | 542 | 665 | 430 |
| | Upper | 720 | 628 | 798 | 500 |
| | Lower | 604 | 467 | 553 | 371 |
| Foreign Partners | Mean | 210 | 173 | 421 | 848 |
| | Upper | 240 | 209 | 481 | 1004 |
| | Lower | 195 | 141 | 368 | 712 |

Note: Yearly cash flows in $ millions.

## 5.3. Probability Distributions of Net Present Values of Cash Flows

The Monte Carlo simulations of cash flows using randomly generated prices and costs produce probability distributions for cash flows. In Figure 6 we show histograms for the probability functions of NPVs of cash flows resulting from the simulations. The figure shows two graphs for the two accounts distinguished in the calculations for each of the projects: the government, and the foreign partner accounts. As discussed in Sections 2 and 3 the accounts receive different shares of receipts from gas, NGL sales, and LNG company cash flows. The horizontal axes show the net present values of total cash flows in US $ millions, the vertical axes show the relative frequencies of the net present values occurring.

### Skewed Distributions

The probability distributions shown in Figure 6 are skewed, i.e. deviations to the positive side of the mean are more likely than deviations to the negative side. This is hardly surprising because it is a property of the lognormal distributions underlying oil price and operating costs in the simulations. But the shape of the resulting probability distributions is not only influenced by the shape of the prior assumptions of input probability distributions. Figure 6 shows for example that the skewness of QatarGas NPV of cash flows is much more pronounced than that of the inputs. This is the effect of the minimum price provision for the

**Figure 6: Cash Flow Frequency Distributions**

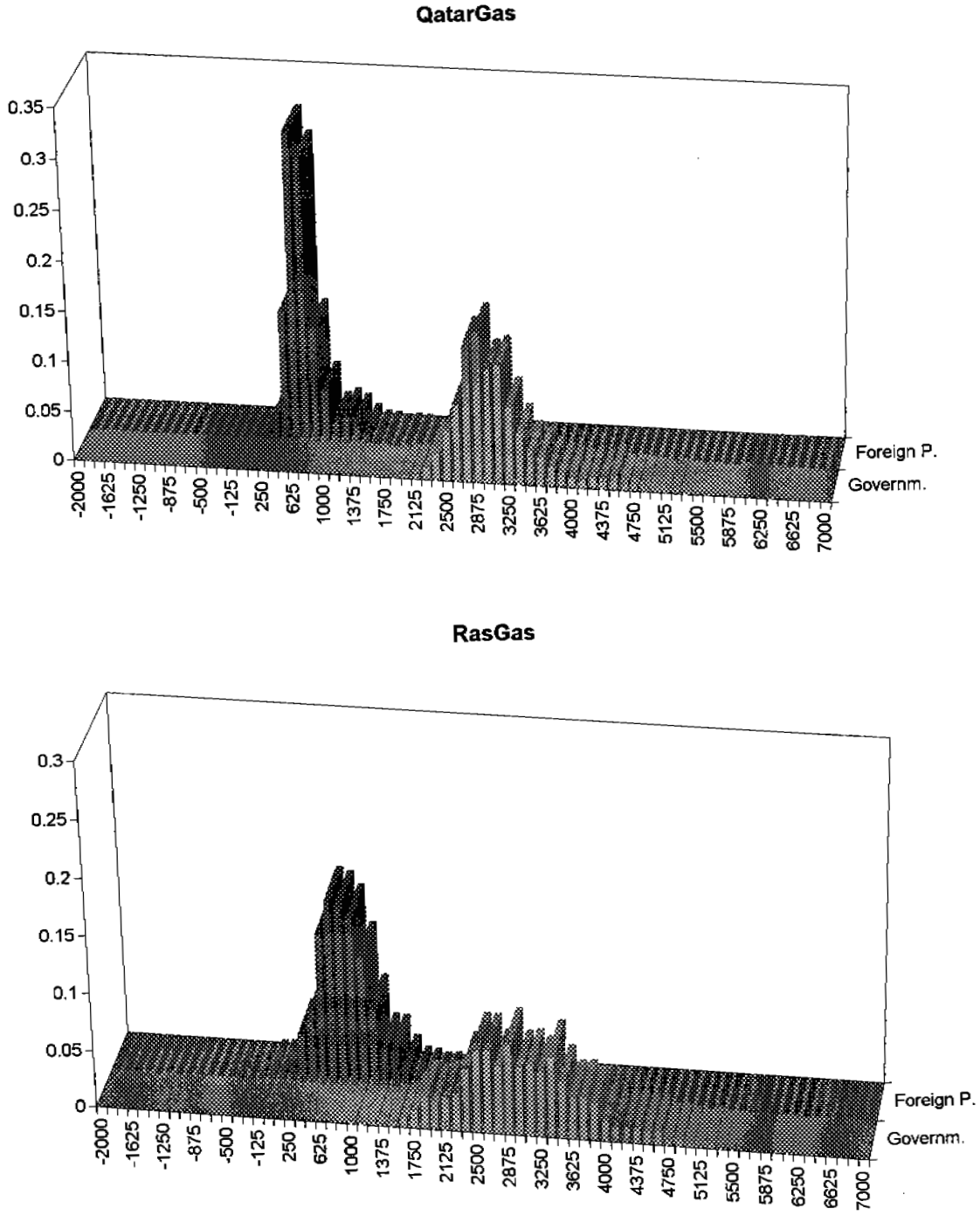
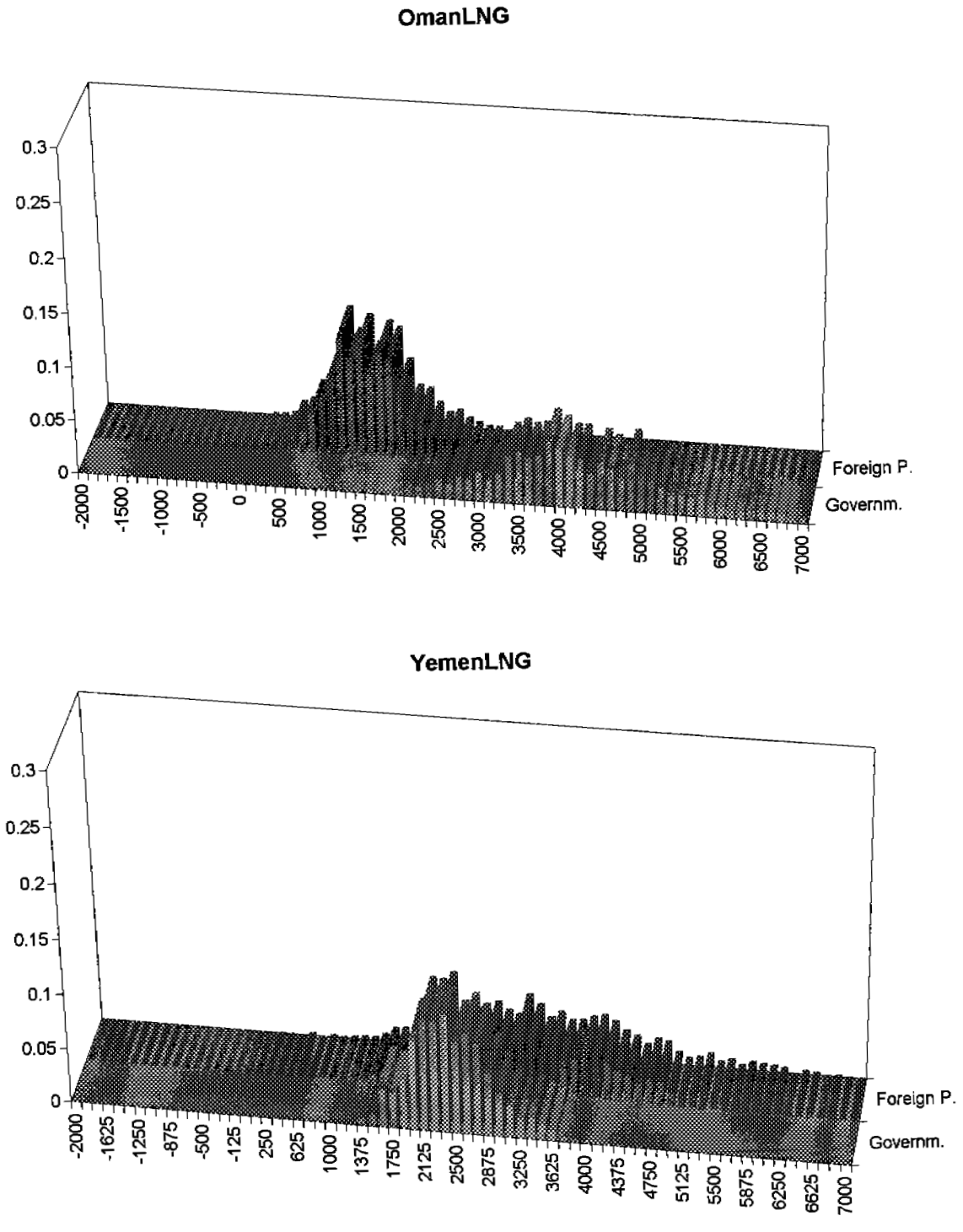


**Figure 6: Cash Flow Frequency Distributions (continued)**




Note: Cash flow frequency distributions for government and foreign partner NPVs of cash flows; vertical axes show relative frequencies, horizontal axes show NPVs of cash flows in $ millions.

sales of LNG. This particular provision in the QatarGas project will be analysed in some detail. Counterfactual analyses are presented in Section 7.

**Risks**

For the risks facing investors in the projects, not only the spread around the mean is important, but also the weight in the tails of the distribution. Comparing the histograms in Figure 6 gives a first idea about the risks taken on by the different investors in the four projects. The distinctly peaked histograms for QatarGas and the government account for Yemen show little risk, whereas the other cash flows are much more spread out around the mean.

The charts show that the government profit guarantee in YemenLNG is of little practical importance in the oil price range underlying the simulations. The guarantee comes into force at a f.o.b. price of $ 2 per mBtu, equivalent to an oil price of $ 11.7 per barrel. This is close to the lowest range in the oil price sample used.

## 5.4. Oil Price Dependent Cash Flow Functions

In the last section probability distributions obtained from Monte Carlo simulations of the NPVs of cash flows were presented. This section looks directly at the relation between cash flows from the LNG projects and the oil prices determining the sales prices of NGL and LNG. Figure 7 shows the NPVs of cash flows plotted against the oil prices in the form of scattergrams.

The vertical axes in each of the charts in Figure 7 show NPVs of cash flows, the horizontal axes show oil prices underlying the sales prices for NGL and LNG fed into the cash flow calculations. Trendlines were fitted to the data as shown. Where trendlines are linear, trendline equations are shown in the charts, i.e. for RasGas and OmanLNG. The trendlines show the values of NPVs of cash flows depending on the oil price for mean values of the other random variables used in the calculations.

The trendlines give an indication of three aspects:

i) The slopes of the trendlines are a first crude indicator of risks. More detailed discussion of risks follows in Section 5.5.

ii) Comparing slopes of trendlines for government and foreign partner accounts gives an indication of government taxation of the projects. Taxation issues will be discussed in the remainder of this section.

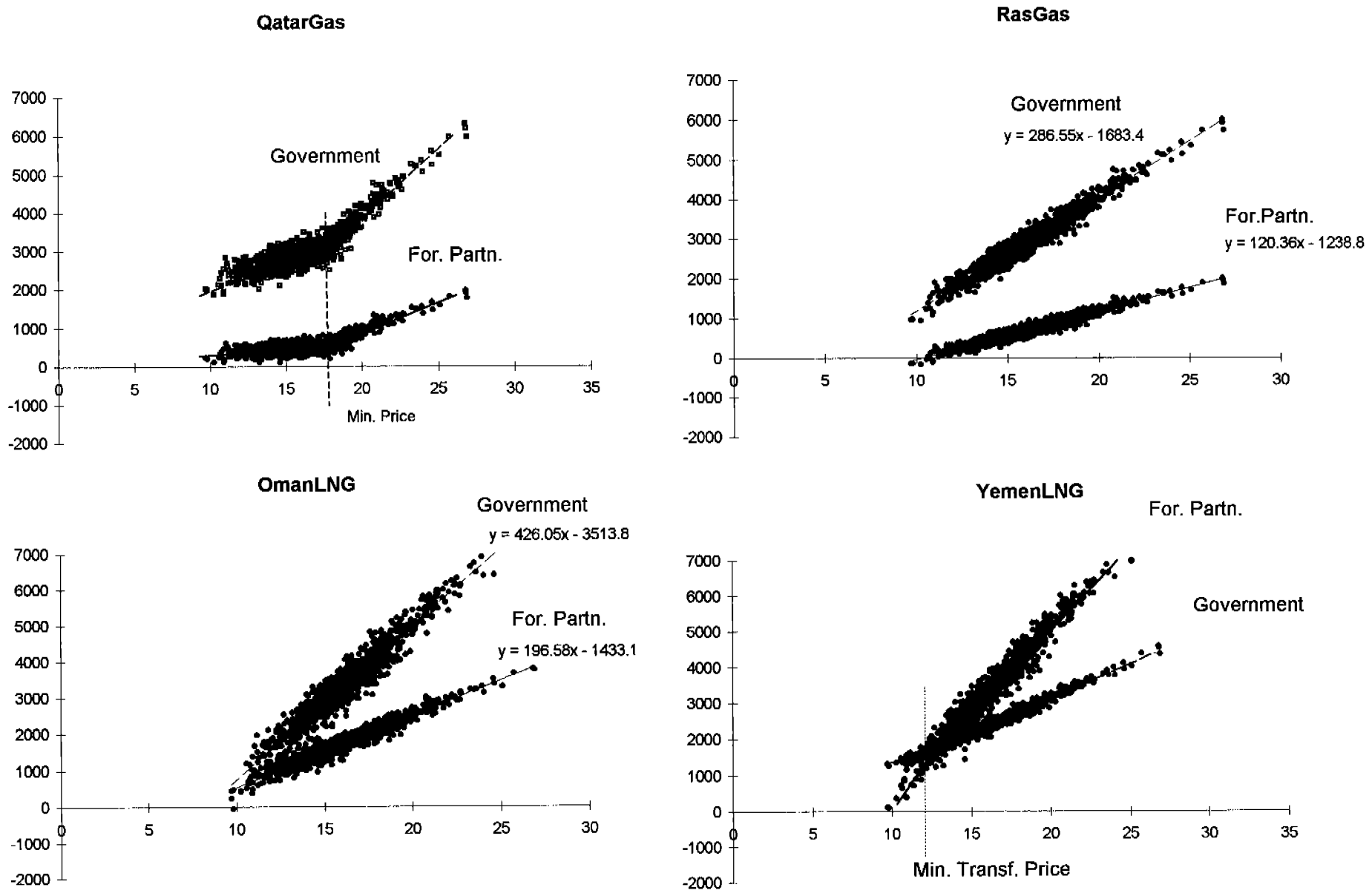
iii) Trendlines can further be used to determine 'minimum-desired' levels of oil prices, i.e. the levels at which the NPVs of cash flows become zero and the trendlines cross the horizontal axes. These are oil prices at which the partners involved in the projects would receive discounted revenues equal to capital investment, or an internal rate of return on capital of 12 per cent. They would be indifferent between investing in the projects or not if the opportunity cost of capital is a return of 12 per cent, as assumed for the NPV calculations. In Section 6 the 'minimum-desired' oil price levels are used to determine minimum supply prices for LNG.

In the cases of QatarGas and Yemen, there is no simple linear relation between oil prices and revenues because of the minimum price provision in the sales contracts of the former, and the minimum profit transfer guarantee in the latter. As mentioned in the last section, the results of counterfactual simulations with regard to minimum price clause is shown in Section 7.

**QatarGas**

The first chart in Figure 7 shows NPVs of cash flows for QatarGas, where LNG sales are protected by a minimum price clause which takes effect at an oil price of about $ 18. The effect of the minimum price clause is clearly visible in the kinked trendline fitted to the two scattergrams in the first chart. The upper line shows the NPVs of cash flows for the government, and the lower line shows the NPVs of cash flows in the foreign partner account. The slopes of the trendlines show that at oil prices above the minimum price, the NPV of government cash flows increases by about $ 380 million for each increase by $ 1 in the oil price, whereas in the foreign partner account the same price increase is worth $ 170 million. NPVs stay positive even at very low oil prices.

**Figure 7: Net Present Values of Cash Flows and Oil Prices**




Note: NPVs plotted against oil prices; vertical axes show NPVs in $ millions, horizontal axes show oil prices in $ per barrel; trendlines fitted where linear correlations; trendline equations shown.

With the difference in slope of the trendlines for government and foreign partners, it is clear that NPVs of government cash flows increase faster than foreign partner cash flows. With increasing oil prices, the government receives ever increasing shares of total revenues. Government revenues above a share in proportion to equity capital contributions are taxation of LNG ventures, and in this sense taxation of QatarGas is progressive, i.e. the marginal tax rate is higher than the average tax rate.

**RasGas**

The scattergram of the NPVs of cash flows in the government and foreign partner accounts of the RasGas venture are shown as the second chart in Figure 7. The slopes of the two graphs are less than the slopes in the QatarGas venture above the minimum price, showing the effect of lower investment costs and higher gearing. A $ 1 increase in the price of oil is worth $ 287 million to the government, $ 120 million to the foreign partners of RasGas. As in the other Qatari venture the government share in total revenues increases with increasing oil prices, or the taxation of the LNG project is progressive. The 'minimum-desired' oil prices, i.e. the prices at which foreign partner NPVs become zero, are about $ 11 per barrel of oil. This oil price will be used in Section 6 to determine the minimum supply price per unit of gas.

**OmanLNG**

In OmanLNG, the difference between the slopes of the trendlines in the scattergrams is less than in the two Qatari ventures. For the government of Oman, an increase by $ 1 in the price of oil means additional NPV revenues of $ 426 million, while it means $ 196 million for the foreign partners. The 'minimum-desired' levels of the oil price where the trendlines cross the horizontal axis are a little lower than in the Qatari cases. The smaller difference in slope between the two trendlines means that the taxation of foreign partner profits from the LNG business is less progressive in Oman than in Qatar. The upward potential for the foreign companies is therefore relatively higher, but also the risk as indicated by the steeper slope of the trendline.

**YemenLNG**

The trendlines for the Yemeni project shown in the fourth chart in Figure 7 are very different from the previous charts. The government cash flows are protected by a minimum transfer guarantee, and this guarantee increases the slope of the trendline for the foreign partner account at a low oil price level. The government NPV trendline is tilted upwards, the foreign partner line downward at the oil price equivalent of the minimum transfer price. The government and foreign partner cash flows diverge strongly at oil prices below the equivalent of the minimum transfer guarantee price of about $ 12.

Unlike in the other three projects looked at, the slope of the government cash flow trendline above the minimum transfer guarantee is lower than that of the foreign partner trendline. At an oil price of about $ 13 the two lines actually cross and the NPV of foreign partner cash flows is actually higher than the NPV of the government cash flows. In this case therefore LNG company taxation – i.e. the share of net revenues taken by the government – decreases with increasing revenues. The much higher risk carried by the foreign partners because of the minimum transfer guarantee is rewarded with a very good upside potential. At oil prices above the minimum transfer guarantee, a $ 1 increase in the price of oil is worth $ 457 million for the foreign partners, as compared with $ 193 million for the government.

## 5.5. Allocation of Risks and Rewards

Using the Profitability and Risk Indicators defined in Section 5.1 we can now interpret the probability distributions shown in Figures 6 and 7. As mentioned in the introduction, profitabilities and risks have been simulated for the four projects first without external finance and based on gross cash flows, i.e. without regard to fiscal regimes and ownership structures; secondly with external finance but still based on gross cash flows; and thirdly for government and foreign partner accounts distinguished in the projects. Figure 8 shows the profitabilities for the four projects in the first chart, and the Risk Indicators in the second chart.

**Profitabilities**

The Profitability Indicators are marked along the vertical axis in the first chart. Profitability Indicators, or capital recovery ratios, are shown in a block of four columns for each of the

four projects. The first column for each of the projects shows the profitability of gross cash flows without gearing. It is determined using gross project cash flow and total investment expenditure. Non-geared gross profitability is highest in the OmanLNG project with a PI of 3.1, while the other projects have PIs between 1.8 and 2.4, i.e. project cash flows are high enough to recover invested capital at a discount rate of 12 per cent, and receive additional profits of about the same magnitude.

Comparing the first with the second columns shows the increase in the Profitability Indicators achieved through debt financing part of the investment costs. Geared PIs are determined using gross cash flows reduced by external finance costs, and dividing by equity capital expenditure only. Using external finance significantly increases the profitability of all the projects. PIs more than double for QatarGas and RasGas and quadruple for OmanLNG, whereas YemenLNG shows relatively little impact of gearing. The differences are caused by the different gearing ratios used in the projects: RasGas and OmanLNG have the highest share of external funds.

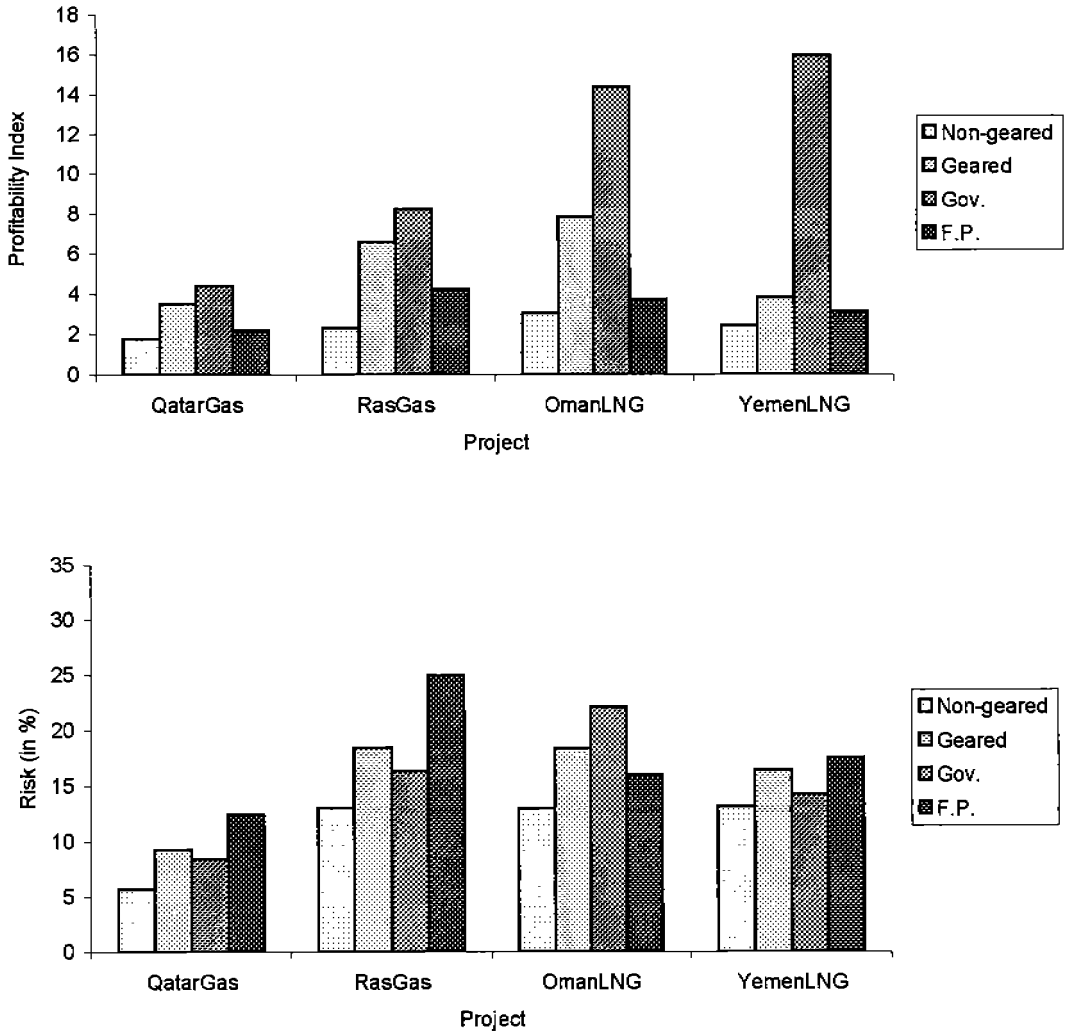
The two remaining columns for each project in the first chart show PIs for government and foreign partner accounts, respectively. In all projects fiscal regimes and ownership structures strongly favour governments, which increase profitabilities compared with the geared gross project cash flows, whereas foreign partner profitabilities are lower. Both the Omani and the Yemeni governments receive NPV of cash flows equal to more than fifteen times their capital investment. In the case of Yemen the government equity contribution is very small, because upstream investments are carried out by YEPC alone. If the data in Figure 8 are interpreted historically, there seems to be a development towards higher profitability for governments and lower for the foreign partners over the time between the setting up of the four joint ventures.

**Risks**

The second chart in Figure 8 compares Risk Indicators for the four projects. Risk Indicators show the average downward change in profitability expressed in per cent of mean profitability. Again, four columns are shown for each project, the first showing riskiness of non-geared gross project cash flows, the second geared gross cash flows, the third and fourth showing risks for government and foreign partner accounts. The comparison between the projects shows the effect of the minimum price for the QatarGas project, which has much

lower risk than the other three projects. In all four cases, external finance increases risks significantly, although the order of magnitude is much less than in the increase of returns shown in the first chart.

**Figure 8: Profitability and Risk Indicators**

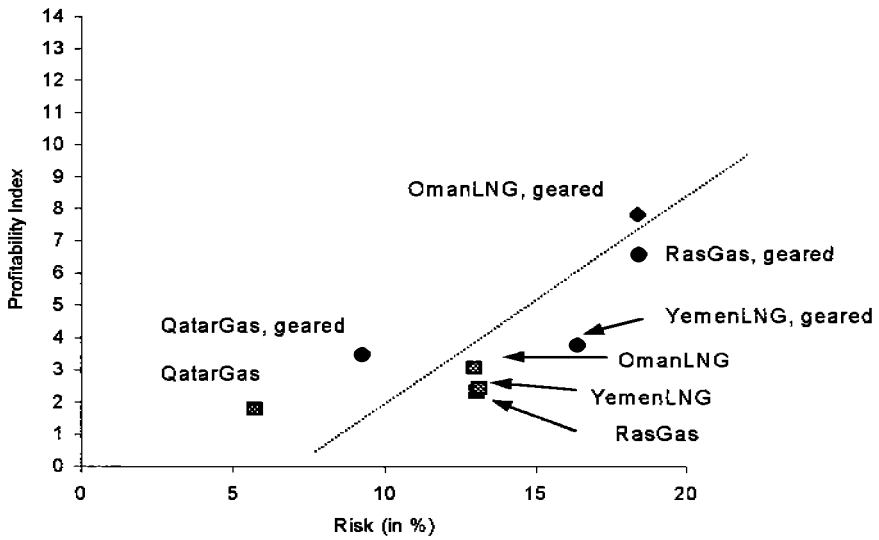



Note: First chart shows profitabilities of projects, block of four columns for each project. First column shows capital recovery factor for gross project cash flows without gearing, second column with gearing. Third and fourth columns for government and foreign partner accounts. Second chart shows risks of projects, defined as average negative deviation from mean Profitability Indicator expressed in per cent of mean PI.

Except for the case of Oman, the government cash flows are less risky than geared gross project cash flows, although governments receive much higher returns. This risk mitigation is most strongly seen in the case of YemenLNG as a result of the transfer guarantee given by the

foreign partners. For the foreign partners, risk exposure is strongest in RasGas, with a RI of 24.9 per cent as compared with risks of less than 20 per cent for OmanLNG and YemenLNG investors.

**Figure 9: Risk-Return Trade Off**




Note: Vertical axis shows Profitability Indicator (equity capital recovery factor), horizontal axis shows Risk Indicator (average negative deviation from mean profitabilities in per cent of mean profitabilities).

## Risk-Return Trade-off

Profitability and Risk Indicators in Figure 8 can be used to analyse the risk-return trade-off which has to be faced when making decisions about the extent of external finance of the projects. In Figure 8 we have plotted Profitability Indicators marked along the vertical axis against Risk Indicators marked along the horizontal axis. For each of the four projects, risk and return combinations are shown for gross project cash flows without and with gearing. A trendline fitted to the data indicates the average trade-off between returns and risks. It shows that on average an increase in the Profitability Indicator by one point increases the Risk Indicator by 4 per cent. For example, the move from a PI of 2 to 3 increases risk from about 8

to 12 per cent. Deviations from the trendline are large and with the small sample of four projects and eight data points the trend is not statistically significant.

# 6. UNIT COSTS AND SUPPLY PRICES

## 6.1. Overview

With the help of the different cash flow simulations shown in the preceding sections, unit costs and minimum supply prices can be determined. These are an important ingredient for a first rough look at the viability of a project. A positive difference between minimum supply price and the market price for gas shows the potential profitability of an export venture. Frequently unit costs are also used to calculate the netback value of gas, i.e. the maximum wellhead price of gas which after adding all production and transport costs, as well as taxes, would lead to a delivered price of the gas equal to the market price or the maximum willingness to pay of potential consumers. This section presents different estimates for the unit costs of gas liquefaction in the four Middle Eastern LNG ventures.

For both the evaluation of the viability of a project and the calculation of netback values of gas it is paramount that the right unit cost estimates be used. These should reflect all aspects of a proposed project, i.e. production of gas and liquids as well as royalties and other aspects of government off-take. Also, estimates should be based on a consistent use of discounting of costs and revenues. To account for the different elements of each project, three different unit cost estimates are presented in Sections 6.2 and 6.3: Gross Unit Costs, Unit Costs with Gearing, and Desired Average Price. We will discuss them in turn in the next section. Section 6.3 then shows estimates for the Middle Eastern LNG ventures. Section 6.4 takes Desired Average Prices and calculates Minimum Supply Prices for Gas. Note that all unit cost and price estimates are on a f.o.b. basis, i.e. transport costs of $ 1.10 per mBtu have to be added for referencing with prices in Japan.

## 6.2. Definitions for Unit Cost Estimation

### Gross Unit Costs

The first estimate in Table 6 takes total costs of the projects, i.e. investment costs plus the operating costs shown in Section 4.3, Table 4, divided by the production volume of NGL and

LNG in British thermal units. Note that in these calculations the payments for raw gas deliveries to the liquefaction plants are costs of the downstream sides and revenues for the upstream sides and therefore cancel each other out because this section looks at both upstream and downstream sections as a unit.

The operating and capital costs in Section 4.3 are shown in NPV terms, i.e. discounting has been applied to yearly cash flows. The calculations use discounted costs and equity capital investments equal to the nominal amounts shown in the beginning of the paper, to calculate costs of equity capital of 12 per cent. So for the calculation of Gross Unit Costs for QatarGas, for example, total funding requirements of $ 4 bn have been used.

Oil prices underlying the cash flow calculations are constant in real terms, i.e. they increase by 3 per cent per year in nominal terms. To compare unit costs and price estimates derived in this section with the prices of oil and LNG used in the cash flow calculations, real prices are determined here. This means the real discount rate of 9 per cent had to be used to derive the discounted number of mBtu produced over the lifetime of the project. The average unit of production would have to be sold at the Gross Unit Cost increasing by 3 per cent per year to produce yearly cash flows with a NPV equal to total costs.

Gross Unit Costs show the minimal average prices required for total hydrocarbon production in order to achieve a return on investment of 9 per cent in real terms, or a NPV of revenues equal to total investment costs plus the NPV of operating costs, when revenues are shared strictly in proportion to capital contribution. Gross Unit Costs compared to market prices or willingness to pay give the crudest possible indication of the 'size of the cake'. It is only a first indicator which helps decision makers to decide whether to enter more deeply into a project and take up negotiations over external finance, production-sharing agreements, royalties, and profit sharing in joint-venture agreements.

**Unit Costs with Gearing**

The numbers shown in the second row in Table 6, Unit Costs with Gearing (UCG), are more sophisticated estimates of the 'size of the cake'. The unit cost estimates described in the previous paragraph take total investment costs and calculate the minimum prices at which the NPV of revenues is sufficient to produce a return on investment of 12 per cent. The second unit cost estimates look at the benefits achieved through partly financing investment costs with external capital at lower interest costs than the 12 per cent discount rate used for the

NPV calculations. The UCG estimates therefore take external finance costs and remaining equity capital expenditures as shown in Section 4.3, Table 4. Compared with Gross Unit Costs, UCGs take into consideration the capital cost savings achieved through gearing as shown in the last row in Table 4.

Given the extent of external financing and therefore a reduction in the cost of capital, Unit Costs with Gearing are necessarily smaller than Gross Unit Costs, because interest rates on external capital are around 7.5 per cent, whereas the NPV calculations use a discount rate of 12 per cent. Calculating Gross Unit Costs assumes a rate of return on all capital of 12 per cent, whereas the Unit Costs with Gearing include this rate of return only for equity capital. The difference between Gross Unit Costs and Unit Costs with Gearing shown in row 3 in Table 6 is therefore the increase in the 'size of the cake' achieved by external financing.

**Desired Average Price**

For a realistic assessment of the costs of gas delivery or netback values of gas the two indicators above are not sufficient. An indicator is needed which gives the minimum price at which the investors in a project would be willing to produce the gas. Unit Costs with Gearing only give this minimum price if project cash flows are shared between investors strictly in proportion to equity capital contributions. In the four projects analysed in this paper, however, governments receive cash flows in excess of their capital share because of royalties and production and profit-sharing agreements. At a price equal to the UCG estimates shown in the second row in Table 6, the NPVs of foreign partner cash flows would therefore be below zero, whereas governments would receive a much higher return on their equity capital.

Foreign companies would therefore not be willing to sign a sales contract which pays only the UCG. Instead, we estimate the Desired Average Price (DAP) which takes fiscal regimes and joint-venture agreements into consideration. The DAPs shown in row 4 in Table 7 are defined as the price of the average unit of energy produced which would result in a zero NPV of foreign partner cash flows. They are determined at the 'minimum-desired' oil prices for the foreign partner accounts shown in Section 5.4.

The determination of DAPs uses the data shown in Table 7. In the first row 'minimum-desired' oil prices are shown. These oil price levels were presented as the oil prices at which the NPVs of cash flows become zero, which are the points where the trendlines shown in Figure 7 in Section 5.4 cross the vertical axes in the charts. Two different 'minimum-desired'

oil prices were identified for each of the projects, one for the government account NPVs and one for the foreign partner account cash flows. For the calculation of DAPs we take the oil price levels at which the NPVs of foreign partner cash flows become zero.

'Minimum-desired' oil price levels are determined iteratively by simulating cash flows for different oil prices until the level is found at which the NPVs of foreign partner cash flows are zero. At this oil price level, the price formulas applied to the actual sales contracts of the LNG projects are used to determine the prices of NGL and LNG, as shown in rows 2 and 3 in Table 7. The thermal units produced shown in rows 4 and 5 are then used to calculate the average unit price, which is the Desired Average Price in the last row in Table 7 and row 4 in Table 6.

The last row in Table 6 finally gives the Government Price Increase, defined in the next paragraph. In Section 6.4, the average supply prices defined as DAPs are translated back into minimum supply prices of gas for different levels of NGL prices. This recognises the fact that a level of oil prices and therefore NGL prices higher than the 'minimum-desired' oil prices in Table 7 allows the foreign partners to offer lower supply prices for LNG and still receive adequate returns on their investment. Higher oil price expectations then can be translated into lower pricing formulas for LNG than the formulas used in the agreements of the four projects.

**Government Price Increase**

Whereas a comparison between Gross Unit Costs and Unit Costs with Gearing shows the increase in the 'size of the cake' achieved by using external finance, a comparison between Desired Average Prices and Unit Costs with Gearing gives an indication of the extent to which the governments participate in gross project cash flows above their shares of equity contribution. By demanding royalties and upstream production shares, the government increases the minimum price at which the foreign partners can count on a positive NPV of cash flows. The Government Price Increase is determined as DAP minus UCG, or row 4 minus row 2 in Table 6.

DAPs are determined from the 'minimum-desired' oil prices given the actual fiscal regimes and profit sharing in the four projects. At these revenue levels foreign partners receive zero NPV profits. Unit Costs with Gearing would give zero NPV profits for both government and foreign partners if all revenues were shared strictly in proportion to equity capital contributions. Moving from UCGs to DAPs shows the increase in the minimum supply

price for energy units brought about by unequal sharing of revenues through the imposition of royalties, upstream production sharing, etc. The differences between the two estimates represent government taxation of LNG companies.

**Table 6: Unit Cost Estimates (in $ per mBtu, f.o.b.)**

| | | *QatarGas* | *RasGas* | *OmanLNG* | *YemenLNG* |
|---|---|---|---|---|---|
| 1 | Gross Unit Costs | 1.81 | 1.54 | 1.29 | 1.52 |
| 2 | Unit Costs with Gearing | 1.61 | 1.36 | 1.19 | 1.43 |
| 3 | Cost Savings through Gearing (1-2) | 0.20 | 0.18 | 0.10 | 0.09 |
| 4 | Minimum Supply Price | 2.09 | 1.81 | 1.28 | 1.85 |
| 5 | Government Price Increase (4-2) | 0.48 | 0.45 | 0.09 | 0.42 |

Note: All numbers in $ per million Btu of average unit of NGL and LNG produced; row 1 determined on the basis of NPV of total investment costs and operating costs, row 2 uses external finance costs and only remaining equity contributions; row 4 copied from Table 7, row 6.

## 6.3. Discussion of Results

### Discussion of Unit Cost Estimates

Gross Unit Costs shown in row 1 of Table 6 are $ 1.81 per mBtu for QatarGas, $ 1.54 for RasGas, $ 1.29 for OmanLNG, and $ 1.52 for YemenLNG. They are highest for QatarGas because of the relatively high investment costs of that project, whereas OmanLNG profits from low investment costs and economies of scale when compared with RasGas and YemenLNG (Yemen produces only a little less LNG than OmanLNG, but much less NGL).

External finance lowers unit costs for all four projects, as shown by the Unit Costs with Gearing. For QatarGas for example, Unit Costs with Gearing are $ 1.61 per mBtu, as compared with $ 1.81 per mBtu without external finance. This shows that the leverage achieved with loan capital brings down unit costs in the case of QatarGas by $ 0.20 per average mBtu produced. The difference between the two unit cost estimates is smaller for RasGas, which has much lower investment costs, therefore a relatively small effect from gearing.

The recourse to the international capital markets reduces unit costs in OmanLNG to $ 1.19 per mBtu, and in YemenLNG to $ 1.43 per mBtu, savings of $ 0.10 and $ 0.09 per mBtu, respectively. The low figure for YemenLNG includes a return of 12 per cent on upstream investment, although the upstream arrangement specifies cost recovery only without uplift, i.e. the interest costs of upstream financing are zero for YemenLNG. To give an indication of minimum prices for gas, some upstream returns for foreign partners had to be included. As in OmanLNG, where upstream investors recover investment costs with 12 per cent uplift, financing costs for YemenLNG and OmanLNG remain the same in the upstream section as if entirely self-financed.

Without debt finance and with equal sharing of cash flows between the partners, sales at a price equal to the Gross Unit Costs shown would produce a revenue stream just big enough to produce a return on investment of 12 per cent. With debt finance, this minimum level of prices is reduced to the UCGs shown in Table 6. In real project arrangements cash flows are not necessarily shared equally between governments and foreign investors, and the latter would therefore not be satisfied with receipts from sales at the UCG level. They need an increase to the Desired Average Prices shown in row 4 in Table 6. These are determined from the 'minimum-desired' oil prices shown in Table 7.

**Table 7: Calculation of Desired Average Prices (in $ per mBtu, f.o.b.)**

| | *QatarGas* | *RasGas* | *OmanLNG* | *YemenLNG* |
|---|---|---|---|---|
| 1 Minimum-desired' Oil Price ($/bl) | 14.00 | 10.50 | 7.20 | 10.80 |
| 2 NGL Price ($ /mBtu) | 2.36 | 1.77 | 1.21 | 1.82 |
| 3 LNG Price ($ /mBtu) | 2.00 | 1.82 | 1.32 | 1.86 |
| 4 Production Upstream ($10^9$ mBtu) | 0.82 | 0.65 | 1.31 | 0.65 |
| 5 Production Downstream ($10^9$ mBtu) | 2.35 | 1.88 | 2.59 | 2.43 |
| 6 Minimum Supply Price ($ /mBtu) | 2.09 | 1.81 | 1.28 | 1.85 |

Note: Row 1 determined iteratively, see text; rows 2 and 3 determined from 1 using pricing formulas in LNG sales contracts; row 6 determined as average between 2 and 3 using 4 and 5 as weights.

The 'minimum-desired' oil price levels for the latter three projects are very close. They are between $ 9 and $ 10.5 per barrel of oil. QatarGas suffers again from high investment costs

and the low price formula for LNG. For YemenLNG, a higher 'minimum-desired' oil price has been identified than for RasGas and OmanLNG. The upstream arrangement of the Yemeni project is between Hunt/Exxon/Yukong and the government of Yemen. The investment capital needed is entirely provided by the foreign shareholders, and cost recovery without uplift in a minimum of five years, and a maximum of 50 per cent of cash flows in any one year, produces a meagre return for these upstream shareholders.

At low oil prices, the NPV of cost recovery is very low, because payments stretch over the lifetime of the project, and the NPV of total upstream cash flows is negative, i.e. the upstream partners receive returns strongly below 12 per cent from their interest in the upstream section, although better returns from the downstream section can partly compensate for this.

The shareholders in the downstream section are Total and Hyundai, which do not take part in the upstream. They are therefore not in danger of receiving low returns from that section, whereas they receive high returns from the downstream section. The sum of NPVs of the foreign partners is zero at an oil price of $ 9 per barrel, but this hides losses for the upstream partners of about $ 250 million, and high returns for the downstream partners. To determine the lowest supply price at which the partners would be willing to contract gas, the 'minimum-desired' level of oil prices for the upstream partners has been chosen – this is the price of oil at which Hunt, Exxon, and Yukong receive revenues high enough to recover their investments in upstream and downstream with a 12 per cent return. The level is shown as $ 10.80 per barrel of oil. At this price, Total receives a NPV of cash flows of $ 600 million.

LNG and NGL price are determined from the 'minimum-desired' oil prices using the LNG price formulas applied to the projects. The average between the two prices is the Desired Average Price for the average mBtu produced by the project, shown in row 4 in Table 6 and row 6 Table 7. QatarGas has to fetch at least $ 2.09 per average mBtu sold in order to produce a positive NPV of cash flows for the foreign companies involved in the project. Note that for QatarGas it is necessary to assume a waiver of the minimum price provision in the sales contract. Otherwise, no sensible 'minimum-desired' level of oil prices can be determined and the concept of minimum sales price underlying the discussions here breaks down.

It is clear that Desired Average Prices differ strongly between the projects. They range from a high of $ 2.09 per mBtu in QatarGas to a low of $ 1.28 per mBtu in OmanLNG. The higher Qatari figure is due to the unfavourable sales price formula, whereas differences

between the other three projects are due to the differing production volumes of NGL. Liquids production is high in Oman compared to the other projects.

The difference between Unit Costs with Gearing and Desired Average Prices is the result of bargaining between governments and foreign investors over the profits from the LNG projects. The last row in Table 6 shows the results of bargaining in terms of the Government Price Increase in the four Middle Eastern LNG ventures. The Government Price Increase is lowest in OmanLNG with $ 0.09 per mBtu, as compared with $ 0.45 in RasGas, and $ 0.42 in YemenLNG. Note that the Government Price Increase includes the effects of payments for raw gas delivered to the liquefaction plants which in the case of the two Qatari ventures are a redistribution of revenues from the shared downstream revenues to the government account, in Oman and Yemen a redistribution between downstream and upstream sections.

## 6.4. Minimum Supply Prices for Gas

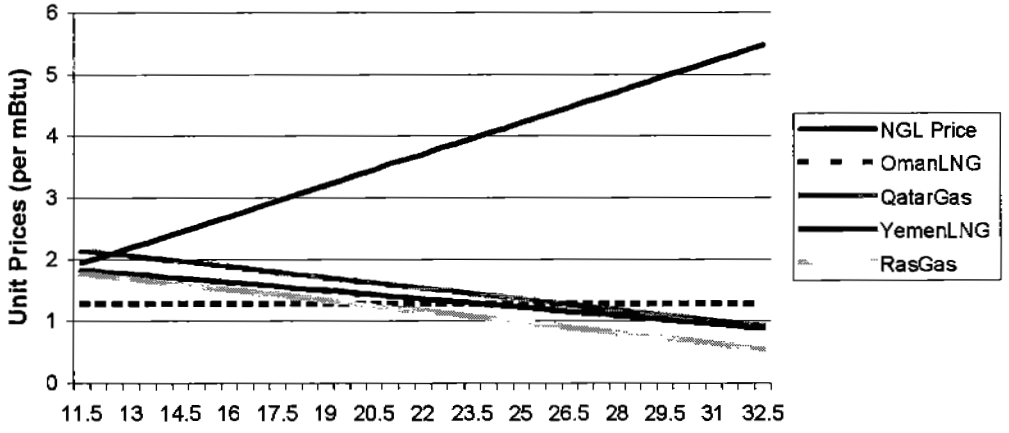
The Desired Average Prices identified in the preceding section are determined for the average unit of hydrocarbons produced by the projects. Project operators obviously can do little about the price at which they sell NGL, because it is determined by the international oil market. The LNG sales prices on the other hand are linked to the price of oil, but the exact form this link takes is the outcome of negotiations between the buyer and the project operators. Given the desired average prices for their output, this section therefore looks at the desired level of gas prices for different oil price scenarios.

This uses the production units of NGL and LNG shown in Table 7. As oil prices and therefore NGL prices increase, the minimum level of prices falls at which foreign partners in the projects would be willing to sell their LNG in order to recover investments. This argumentation is not true in the case of OmanLNG, because foreign partners receive a fixed return of 12 per cent on upstream investment. They therefore do not take part in a higher profitability of the upstream part in the case of high oil prices. On the other hand, they are protected against low profitability when oil prices are low. The Omani Minimum Supply Price for Gas therefore stays at the level already shown in Table 7.

Figure 10 shows oil prices in the horizontal axis, and corresponding prices per mBtu of NGL and LNG on the vertical axis. The upward sloping first graph shows NGL prices derived from the oil prices using a conversion factor of 6 mBtu per barrel of oil. The three downward

sloping graphs below are Minimum Supply Prices for Gas for the three projects, while OmanLNG price stays constant.

**Figure 10: Minimum Supply Prices and Oil Prices (in $ per mBtu, f.o.b.)**




Note: NGL and minimum supply prices for LNG (f.o.b.) plotted against oil prices (f.o.b.); minimum supply prices for LNG determined for given NGL prices to result in zero NPV of foreign partner cash flows; all prices in $ per mBtu.

An excerpt of the data underlying Figure 10 is shown in Table 8. It shows minimum supply prices for LNG on a f.o.b. basis for the four projects for oil prices of $ 13, $ 16, and $ 19 per barrel.

**Table 8: NGL and Minimum Supply Prices for LNG ( in $ per mBtu, f.o.b.)**

| | *NGL Price* | *LNG Price* | | | |
|---|---|---|---|---|---|
| | | *QatarGas* | *RasGas* | *OmanLNG* | *YemenLNG* |
| Oil Price $ 13 | 2.19 | 2.06 | 1.68 | 1.28 | 1.76 |
| Oil Price $ 16 | 2.69 | 1.88 | 1.50 | 1.28 | 1.62 |
| Oil Price $ 19 | 3.20 | 1.70 | 1.33 | 1.28 | 1.49 |

Note: Minimum supply prices for LNG (f.o.b.) for given oil and NGL prices, at which NPVs of foreign partners are zero; oil prices in $ per barrel, all other prices in $ per mBtu.

NGL prices determined by the oil prices are shown in the first column. For example, at a price of oil of $ 16, NGL is sold at $ 2.69 per mBtu. Given oil price expectations of say, $ 16 per barrel in real terms over the lifetime of the project, foreign investors would contract LNG sales at a minimum of $ 1.88 per mBtu from the QatarGas project, $ 1.50 from RasGas, and $ 1.62 from YemenLNG. If oil price expectations are higher, and therefore NGL sales revenues are higher, foreign investors would be willing to agree to lower LNG sales prices in the three projects except OmanLNG, with minimum levels for an oil price of $ 19 per barrel shown in the last row in Table 8.

The table shows that minimum LNG sales prices for QatarGas are $ 0.30 above those of the other Qatari and the Yemeni projects. However, the minimum price at the mean oil price level is much lower than the current minimum price level agreed upon in the sales contract with Chubu Electric of $ 3.60 per mBtu c.i.f., i.e. $ 2.50 per mBtu on a f.o.b. basis. Taking the mean oil price assumption used throughout this paper of $ 16 per barrel and adding the transport costs of $ 1.10 per mBtu, Table 8 shows that gas could reach Japan for $ 2.90 per mBtu from QatarGas, $ 2.60 from RasGas, $ 2.70 from Yemen, and $ 2.40 from Oman. The service agreement in the upstream part of the Omani venture means that higher NGL prices cannot subsidize the downstream part for the foreign partners.

Looking at potential supplies to Europe, gas could be brought to Turkey at a transport cost of about $ 0.70 per mBtu, of which the Suez canal passage is about $ 0.30 per mBtu. This means minimum supply prices in Turkey would be $ 2.50 per mBtu from QatarGas, or $ 2.30 from YemenLNG, if oil prices are expected to stay around $ 16 in real terms over the next two decades. These gas price levels are competitive with Turkey's import prices from Russia or Turkmenistan.

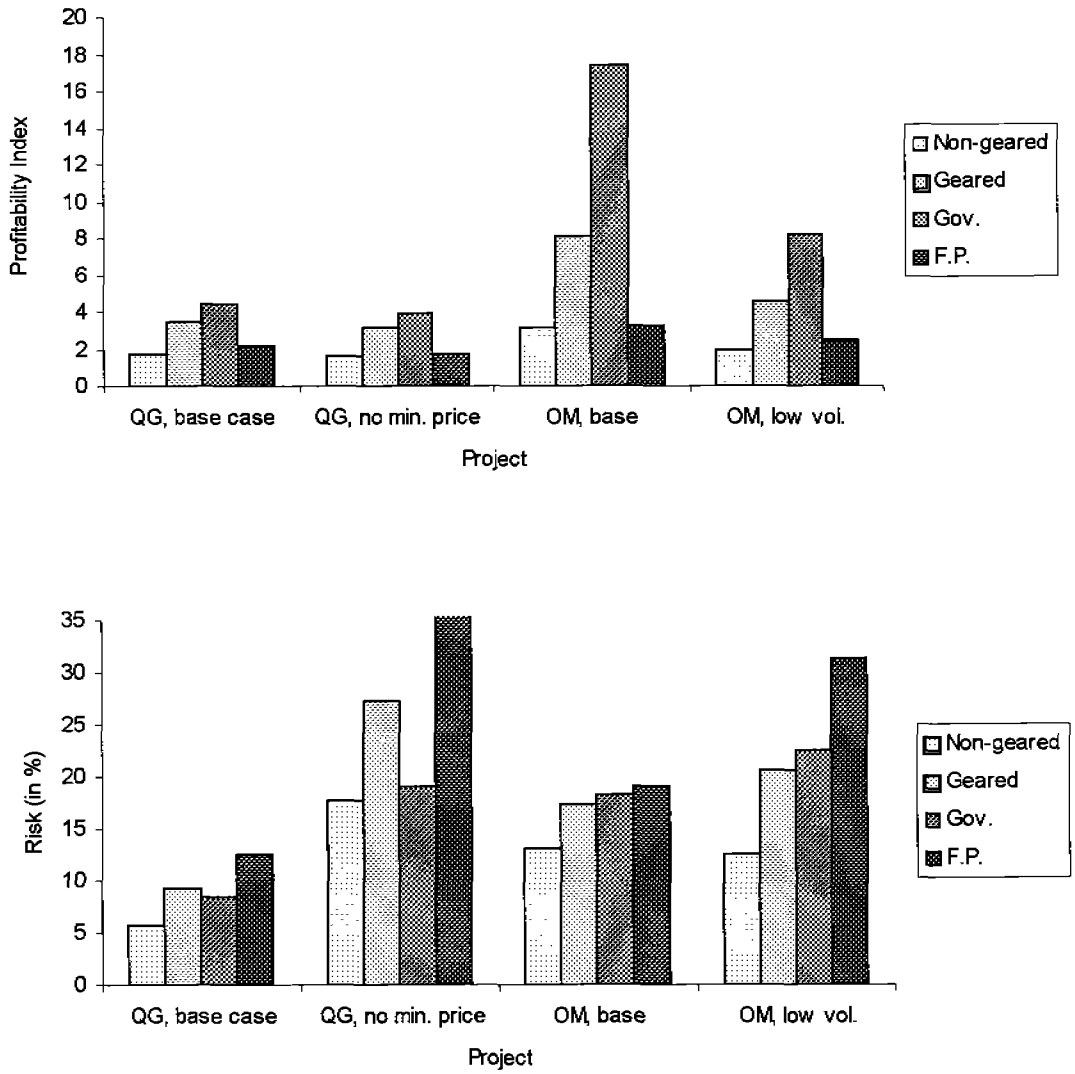
# 7. COUNTERFACTUAL SIMULATIONS: MINIMUM PRICE FOR QATAR AND SALES VOLUMES FOR OMAN

In Sections 4 and 5 it has been shown how QatarGas cash flows benefit from a minimum price clause as agreed upon in a memorandum of understanding between QatarGas and Chubu Electric, the buyer of the entire volume of LNG production. However, pricing formula and minimum price clause have never been laid down in a formal pricing agreement, which is still under negotiation one year after start-up of LNG deliveries. Section 7.1 looks at a possible result of the negotiations: a waiver of the minimum price clause. Counterfactual cash flow simulations are presented.

In the second part of this section we take a look at the Omani project. OmanLNG has signed a favourable contract with KGC over 4.8 million tons per year of LNG at a high price. As mentioned, a buyer for the additional 2.8 million tons per year of capacity has yet to be found. Section 7.2 simulates cash flows for OmanLNG in the worst case, where no buyer is found and the extra capacity is idle. This gives a lower bound scenario, whereas in reality additional volumes will probably be marketed at a reduced price.

Figure 11 summarises the results of the counterfactual simulations for the two projects. The first chart shows the Profitability Indicators marked along the vertical axis, the second chart shows Risk Indicators. The first two blocks of columns in the two charts show data for QatarGas, the last two show data for OmanLNG. For both projects, the first block of columns shows data for the base case, i.e. profitabilities and risks for QatarGas with minimum price protection, and for OmanLNG with full volume sales. In each block, the first column shows profitability and risk of NPVs of gross project cash flows without gearing, the second column with gearing. The third column shows data for the government account, the fourth data for the foreign partner account.

**Figure 11: Profitability and Risk Indicators from Counterfactual Simulations**




## 7.1. Renegotiating a Price Agreement for QatarGas

In Section 5 it was shown that QatarGas enjoys a relatively low risk because of the minimum price clause in the preliminary sales contract. The first block of columns in Figure 11 shows Profitability Indicators for QatarGas as in Figure 6, the second block of columns shows the result of a waiver of the minimum price on returns.

Obviously, returns as measured by the Profitability Indicator decline because the mean oil price in the simulations is lower than the minimum price underlying the preliminary LNG sales. Gross project profitability drops from 1.8 to 1.6, whereas profitability with gearing drops from 3.5 to 3.1. The risk of returns for QatarGas is very low in the base case, as shown

in the second chart in Figure 11. Waiving the minimum price protection brings a big increase in risks, to a level much higher than in any of the other projects in the comparison. As before, government risk is significantly below gross project risk and foreign partner risk because of royalties and production sharing, which bring a less volatile revenue stream than the profit shares in the LNG project.

The results show that QatarGas agreed to relatively low prices for LNG because it receives considerable protection by the minimum price clause. Put the other way, OmanLNG agreed to a pricing formula without minimum price for a considerable compensation by high average prices. It seems therefore unlikely that the QatarGas project partners will agree to a waiver of the minimum price clause without a price improvement at the same time.

## 7.2. Reducing Sales Volume for OmanLNG

The second counterfactual simulation presented in Figure 11 shows the effects of a reduction in sales volumes on returns and risks for OmanLNG. The figure shows the base case returns and risks in the third block of columns in both charts, and a 'worst-case' scenario in the fourth block. OmanLNG has signed a sales contract with KGC for only about two-thirds of its capacity, and the simulations here show returns and risks prevalent if no other buyers are found.

Reducing the sales volume by about one-third reduces the profitability of OmanLNG from 8 to about 5 on a geared project basis. The government recovery factor declines from the very high base case of more than 17 to a still impressive 8, whereas foreign partner profitability declines from 3 to 2.4. OmanLNG is then still more profitable than the base case QatarGas project, and at least for the government also more profitable than RasGas.

Risks increase likewise if production volumes decline, from less than 20 per cent to more than 30 per cent for the foreign partners. OmanLNG is then more risky than any of the other projects in the original simulations, but still less risky than QatarGas without a minimum price clause as shown in the last section. This shows an extraordinary robustness of the Omani project.

# 8. SUMMARY AND CONCLUSIONS

Looking at the latest four Middle Eastern LNG projects in Qatar, Oman, and Yemen in detail, the study has shown the effects of project finance, fiscal regimes, and ownership structures on project cash flows, returns on investment by project partners, and project risks. In the early 1990s, project planning started for two LNG plants in Qatar, one in Oman, and one in Yemen. The benchmark data provided in Section 2 have shown that after QatarGas, the other projects have reduced total funding requirements considerably. Costs savings through technological development exist, where the main progress is an increase in component size allowing economies of scale. A bigger impact on project costs, however, is ascribed more to the bidding conditions than to technological development.

The four projects are similar in size, with only the second Qatari project, RasGas, below average. However, an expansion of the RasGas plant is planned, albeit without a time frame. The projects are scheduled to produce varying amounts of Natural Gas Liquids associated with the gas output, which form an important source of extra revenue. Oman is thought to have the wettest gas, with Qatar following closely, and Yemen lagging behind with relatively dry gas. This has a strong impact on project profitability.

The three countries impose different fiscal conditions on the projects: foreign investors in Qatar work under a production-sharing agreement, where the government owns the dry gas sold at a fixed price to the liquefaction plant, and NGL is subject to royalty and government production share. In Oman on the other hand, the upstream section is operated under a service contract with fixed returns for the foreign investors. Yemen allows cost recovery out of upstream production, and profits are shared between the government and the upstream partners. These fiscal conditions are usually the outcome of historical developments and negotiations with foreign companies over a long period of time, and not geared specifically to the LNG project. They reflect both negotiating skill on behalf of the governments, and also relative strength of a country in the international arena, which depends for example on reserve size and political affiliations, etc.

All projects use large amounts of external capital, up to 80 per cent of total downstream funding requirements in the Omani project. All financing is on a non-recourse basis, which means only project assets are liable for debt repayments whereas shareholders cannot be held responsible. This shows an increasing willingness by international banks to provide LNG

finance at competitive rates. The financing of RasGas and OmanLNG has partly been provided by bond sales on international financial markets, where RasGas was the first Middle Eastern project ever to issue bonds on a non-recourse basis, and OmanLNG was the first project to close the financing arrangements and start project construction while only a buyer for two-thirds of planned capacity had been found. In both cases lender risks were perceived to be small, in RasGas because of the positive experience with neighbouring QatarGas, in Oman because of the strong project profitability.

In all the projects discussed in the paper, ships for the transportation of liquefied gas are owned by shipping consortia, and chartered by either buyers or sellers on a long-term basis. Therefore, transportation costs are running costs for the projects whereas capital investment is separate from the LNG projects. For the calculations shown in the paper, transportation costs are fixed and it does not matter whether output is sold on a f.o.b. or c.i.f. basis. This is a strong simplification, because a company with c.i.f. contracts and its own ships has considerable flexibility in selling excess capacity on a spot basis.

The two pricing formulas underlying the calculations shown in the paper are for QatarGas, which determines prices on a c.i.f. basis, and OmanLNG, with f.o.b. pricing. The Qatari contract included initially a minimum price and relatively low LNG prices at oil prices above the minimum price. The Omani contract was the first signed without minimum price clause, and the company has achieved a considerably higher price link to oil prices than QatarGas in return, both for the waiver of the minimum price and for giving up the flexibility of having ships at its disposal. OmanLNG has therefore a very high earnings potential at the mean oil prices used throughout the paper.

The project partners are the national governments and a collection of foreign investors. The joint ventures usually bring together international oil companies with trading and financing houses from Asia, the main market for LNG. In Oman, the Korea Gas Company as the main buyer insisted on equity participation, whereas Hyundai joined the Yemeni project with its ship building interest. Upstream and downstream sections operate under quite different types of agreements in Oman and Yemen, and equity and profit shares differ strongly between partners. Especially striking is the fact that Total as the lead operator of YemenLNG has no exposure to the upstream section which is operated and financed by the Yemen Exploration and Production Company (YEPC), consisting of Hunt, Exxon, and Yukong.

Section 4 has shown cash flow components for the four LNG projects in the Middle East, both for an example year, and in terms of the NPVs of lifetime costs and revenues. The

differences in fiscal regimes, ownership, and financing arrangements summarised above can be recognised in the cash flow components. The section has shown that LNG sales revenues for QatarGas are inflated considerably because of the minimum price guarantee given by the Japanese buyers. Also, NGL sales revenues are worth less than half of LNG revenues in all the projects. In fact, LNG revenues are high enough to finance both upstream and downstream sections of the projects. It is therefore not true that profitable liquids extraction subsidises an otherwise unprofitable LNG business, as is often claimed in the trade press.

Despite the high profitability of the downstream sections, government taxation is paradoxically applied to the upstream sections, whereas the government participates in proportion to equity capital contribution downstream. The only exception is the Yemeni project, where the government levies a royalty on LNG sales, and government profit shares increase over the lifetime of the project, i.e. are independent of government equity contribution.

The comparison of the NPVs of project cash flows shows that QatarGas suffers from very high investment costs compared to the other projects and the high profitability of OmanLNG relative to YemenLNG, which is due to lower financing costs, higher NGL production, and a more favourable pricing formula. The Yemeni project has been planned on the basis of 60 per cent external finance for the downstream section, which means cost savings through gearing are relatively low. The other projects achieve cost savings of 10–12 per cent through gearing, compared with only 6 per cent in YemenLNG. An increase in the desired gearing ratio can therefore be expected in the future.

Section 5 has shown that project risks are below 20 per cent on a geared, gross project basis, i.e. the average negative deviation of capital recovery factors is about 20 per cent from the mean, except for QatarGas where risk is very low because of the minimum price clause in the contract.

The section looked in detail into the sharing of risks and rewards between governments and foreign companies. The four projects lead to quite different profit expectations for the partners involved. Government rewards are significantly higher than those of the foreign partners in all the projects, even in the case of Yemen because of very low government equity capital contribution, whereas risks are pointedly higher for the foreign partners.

The section compared the variability of gross project cash flows with the variability of government and foreign partner cash flows for each of the projects. This shows that LNG company agreements achieve risk mitigation for the national governments, mainly through

increasing government revenues above equity contributions. Foreign partners in contrast have to accept increases in risks compared to geared project risks.

These results of the comparison of NPVs of cash flows between the four projects show the effects of different ownership arrangements on the sharing of returns and risks from the LNG ventures. The production-sharing agreements in Qatar produce high returns for the government, with low risks, and the opposite is true of the foreign partner cash flows. The service contract agreement under which PDO operates the upstream section of OmanLNG is an insurance for the foreign partners in the project, which means NPVs of government cash flows are more risky than gross project cash flows, and the foreign partners face relatively little risk (compared to the other projects, but foreign partner risk is still above gross project risk).

Foreign partner risks are high in YemenLNG because of a profit guarantee given to the government. It has also become clear that RasGas would benefit greatly from the economies of scale it could achieve with the construction of a third train, if buyers at the relatively high sales price for the initial 4.8 mt of LNG could be found. In its current form, the project has relatively low returns, and higher risks compared with the other projects.

Over the time elapsed between the finalising of each of the four projects, government returns increased at the cost of foreign partner returns. The first Qatari project created the impression that LNG plants can be highly profitable and governments demanded higher shares. Also, the experiences gained with QatarGas showed that projects could be completed on schedule. At the same time, demand expectations in Asia showed a gap into which several LNG projects could be placed, and a certain amount of competition ensued between different supply options. This weakened the bargaining position of major oil companies against the governments.

The positive experiences with QatarGas also opened the way for easy external financing, in addition helped by high liquidity in the international financial market. After the financial and currency crises in Asia at the end of 1997 and the beginning of 1998, the situation now looks different. Demand expectations for the Asian market have been revised downward, and lenders' willingness to support projects aimed at the Asian market is significantly reduced. The fast creation of three LNG projects in the Middle East over the first half of the 1990s is the result of a historical opportunity which might not present itself again in the near future. The prospects for the Yemeni project, which missed the window of opportunity by only two years or so, do not look too good.

Likewise, the downward revision of expectations is bound to have an effect on the ongoing price negotiations between QatarGas and Chubu Electric. Section 7 has shown that a waiver of the minimum price clause in the initial letter of intent, will cost QatarGas through a reduction in the expected NPV of cash flows and an increase in profitability risk. QatarGas would become the most risky of the projects while still being the least profitable. The considerable pressure put on LNG producers by the sluggish demand forecasts for the Asian market might mean that QatarGas will have to agree to this outcome. The paper predicts a probability of 20 per cent that the NPV of foreign partners will actually be negative in the case of the unfavourable outcome.

Section 6 has shown unit costs and minimum supply prices for the four projects. It is shown that Gross Unit Costs, defined as total investment and operating costs per average energy unit produced, are $ 0.30-0.50 per mBtu higher for QatarGas than for the other projects. Some of this cost disadvantage is mitigated by external financing, and fiscal regimes, but it was shown that the Desired Average Price for QatarGas is still more than $ 0.20 per mBtu above RasGas and OmanLNG.

The section stressed the importance of oil price expectations. Because Natural Gas Liquids are 20 to 40 per cent of the energy units produced minimum supply prices for LNG should take NGL revenues into consideration. It was shown in Section 6 how the prices at which LNG companies would be willing to sell gas change with changing oil price expectations. Section 6 estimated minimum supply prices for LNG of $ 1.80 per mBtu for QatarGas, $ 1.60 per mBtu for YemenLNG, $ 1.45 for RasGas, and $ 1.60 per mBtu for OmanLNG. These estimates are on a f.o.b. basis and for the mean oil price assumption of $ 16 per barrel used throughout the paper. They take into account the actual project arrangements with fiscal regimes and ownership structures, and the revenues from the sales of NGL. With firm oil price expectations, Middle Eastern LNG could make major inroads into Europe.

On the other hand, if the current low oil price levels are thought to continue, minimum supply prices for gas would increase to around $ 2.10 for QatarGas and YemenLNG, and $ 1.80 per mBtu for RasGas, levels which are not competitive with European gas prices. Again, this does not lead to an optimistic evaluation of the prospects of YemenLNG.

The OmanLNG minimum supply prices for gas are different from the three other projects as they are not influenced by sales revenues for NGL. This is the effect of the service agreement in the upstream section, which means foreign partner returns are always 12 per cent in that section. Higher NGL revenues can therefore not subsidise LNG prices as in the

other companies where the returns depend on both upstream and downstream sections. High oil price expectations would therefore lead to a loss of competitiveness of the Omani project.

Finally it has to be stressed that the LNG projects looked at in this paper are likely to be highly profitable investments over the long term. Projects have a lifetime over 25 years at least, and if reserves permit they can be kept going for longer than that. After repayment of external loans, LNG plants produce a sizeable stream of revenues for investors and national governments alike, and the expected NPVs of projects promise a manifold recovery of equity investment. The downward revision of expectations for the Asian market are likely to be a temporary hiccup, with greenfield projects and even plant extensions being delayed a few years.

# ANNEX 1: PROBABILITY DISTRIBUTIONS

For the Monte Carlo simulations, assumptions have to be made about probability distributions of the variables used. Oil prices and operating costs are sampled from lognormal distributions, interest rates from a normal distribution. The international oil market is an imperfect market and long-term price predictions are extremely difficult. In the past, oil prices have fluctuated around a relatively stable average of about $ 10-15 per barrel in real terms, up to the events of the 1970s, when OPEC and other factors increased prices and volatility.[7] Because of the non-competitive nature of the market, the past volatility cannot be used as indicator of future volatility. OPEC production decisions, sudden political crises, etc. cannot be modelled and forecast with any claim to accuracy.

Existing econometric analyses of oil prices in the literature have mostly looked at short-term volatility and are therefore of little use for this research which looks at oil prices over the lifetimes of the LNG projects, which span a quarter of a century. The probability distribution for the oil prices used in this study therefore had to be based merely on an 'educated guess'. A lognormal distribution was chosen to account for the high upwards flexibility of oil prices in times of crises, as happened for example in 1973 and 1990 after the invasion of Kuwait by Iraqi forces.

A histogram for the oil price distribution is shown in Section 5.1. The mean oil price is $ 16 per barrel, the average negative deviation is $ 2. Summary statistics are shown in Table A1.

**Table A 1: Summary Statistics for Oil Price Distribution**

| | |
|---|---|
| Mean | 16.23 |
| Standard Deviation | 2.56 |
| Kurtosis | 0.89 |
| Skewness | 0.58 |
| Count | 1000.00 |

Note: Summary statistics for oil price distribution underlying cash flow calculations; distribution histogram shown in Section 5.1.

[7] See *BP Statistical Review of World Energy 1997*, p. 14.

For the modelling of operating costs a lognormal distribution was chosen, as customary in engineering studies.[8] The mean values of probability distributions for operating costs are $ 245 per million cubic feet of gas in the upstream section, $ 0.41 per mBtu in the downstream section of the projects, the standard deviations are 20 per cent of the mean.

International interest rates are determined competitively and can be modelled as random walks, a normal distribution seems therefore more appropriate. The LIBOR interest rate underlying rates paid on external finance by the projects is modelled as a normal distribution with a mean value of 6.3 per cent and a standard deviation of 2 per cent, i.e. 64 per cent of rates sampled will be within a range of 4.1 and 8.5 per cent.

**Random Profiles**

To simplify matters the stochastic variables remain constant in real terms over the lifetime of the projects of 28 years, i.e. for each calculation run a certain combination of oil price, interest rate, and operating costs is chosen in $T_0$ and kept over the project lifetime. An alternative would be the simulation of stochastic time profiles for the three variables, i.e. randomly generating different prices and costs for each year during the project lifetime. Instead of 1000 trial runs of constant trends we would simulate different prices and costs for each year, or each quarter.

The data generation increases immensely, but the differences between results obtained from the simulation of random profiles and constant random trends are small. They are only a result of the discounting of cash flows over the lifetime of the project in the sense that some profiles have lower prices in the early periods and some in the later periods. Because of discounting later revenues are valued less than early revenues. The extra risk introduced by this aspect of the world, which is lost in the calculations used here, is very small when compared with the risk from random price trend lines over the whole lifetime of the project, and does not warrant the immense increase in use of computing resources.

[8] See for example Abosedra and Laopodis [1997]. For a cogently argued history of oil see for example Adelman [1995]. See Vose [1996] for an account of distributions used in engineering.

# ANNEX 2: SUMMARY STATISTICS AND RISK MEASURES FOR THE CASH FLOW PROBABILITY DISTRIBUTIONS

The Monte Carlo simulations result in probability distributions for the NPVs of cash flows. Some statistical tools are needed to interpret the results. These are the mean of NPVs of cash flows, or the expected value of NPVs, and measures for the spread of outcomes around the mean. The mean is simply determined as the sum of NPVs of cash flows over the 1000 trials divided by 1000. As a measure of dispersion of the cash flows we could then calculate the mean average deviation (AD), determined as

$$AD = \frac{\sum_{1}^{n} |x_i - \bar{x}|}{n}, \qquad (1)$$

where $n$ is the number of trials, $x_i$ is a sample NPV of cash flows, and $\bar{x}$ is the mean of NPVs of cash flows. The mean AD is a more useful indicator for the spread of possible outcomes than the more common mean standard deviation (SD). The latter is determined by calculating the sum of the squares of deviations of outcomes from the mean and taking the square root. The squaring gives a high weighting to extreme outcomes and SD is therefore less intuitive.

Measures of dispersion such as SD and AD can be used to calculate measures of risk, the former for the commonly used coefficient of variation (ratio of SD to mean), but in the case of the LNG cash flows this is of limited value. Because of the lognormal distribution underlying the random variables in the calculations, deviations to the positive side are more likely than to the negative side. A business or government planner would not be worried too much about the former as opposed to the latter. The common measures of dispersion will therefore not adequately reflect the risk of a project. We calculate instead average positive and negative deviations.

For this the sample of 1000 cash flows obtained for each of the accounts in the projects is divided into two sub-samples: those which deviate positively from the mean, and those which show a negative deviation. We then calculate the average for the two sub-samples by summing and dividing by the number of elements in the sub-sample. The mean plus the average positive deviation (APD) then shows an upper range, the mean minus the absolute value of the negative deviation (AND) shows a lower range of project outcomes. These upper

and lower range figures show a band in which about 70 per cent of outcomes are to be found in the simulations.

In addition, the probability of obtaining cash flows below zero, or below any number *y*, can be calculated by summing relative frequencies of cash flows below *y*:

$$p\{x_j < y\} = \sum_j p_j(x_j) \qquad \forall j = \{j | x_j < y\} \qquad (2)$$

where *j* is defined over all negative cash flows, $p_j$ is the relative frequency of sample value *j*, and *p* is the probability of obtaining cash flows below *y* or zero. This gives additional information about the downside risks of the projects. In Annex 3 simulated mean and ranges of NPVs, and the probability of NPVs equal to or smaller than zero are presented.

Mean NPVs and deviations from the mean are not meaningful on their own as they do not take into consideration the investment costs which have to be incurred before any NPV of cash flows can be enjoyed. Therefore the mean NPVs are transformed into Profitability Indicators, and the deviations from the means into Risk Indicators. The **Profitability Indicator (PI)** is one plus the mean of the net present value of either government or foreign partner cash flows divided by the equity capital invested by either government or foreign partners. Algebraically, this reads as follows:

$$PI_P = 1 + \frac{\mu_P(NPV)}{E_P} \qquad (3)$$

where the subscript P denotes government or foreign partners, $\mu(NPV)$ is the mean of the NPV of cash flows, and E is the equity capital invested.

The **Risk Indicator (RI)** is the difference between the average profitability and the average low profitability expressed in per cent of the average profitability. First the average negative deviation from the mean is determined, and using this the average low profitability. Then the difference between mean and average low profitability is expressed in per cent of the mean profitability. Algebraically:

$$RI_P = \frac{PI_P - \frac{1 + \mu_P(NPV) - \frac{x_P(NPV) - \mu_P(NPV)}{n}}{E_P}}{PI_P} * 100\% \qquad (4)$$

where the symbols are the same as above, and x is a single outcome of the NPV simulations, n is the number of simulations.

# ANNEX 3: MEAN NPVs OF CASH FLOWS AND RANGES OF CASH FLOWS

This annex gives descriptive statistics for the probability distributions of NPVs of cash flows underlying the discussions in Sections 5 and 7. Here mean NPVs and upper and lower ranges are presented in absolute terms, the same numbers as underlying Figures 5 and 6.

**QatarGas**

The first two columns in Table A2 show the results of Monte Carlo simulations for QatarGas. The mean NPV of cash flows for the government (including the national oil company) and the foreign joint-venture partners is shown in the first row: government NPV of cash flow is $ 3042 million, $ 563 million for the foreign partners. The next two rows show lower and upper level of cash flows (see Section 5.1). Even for the foreign partner account, the risk of a negative NPV of cash flows is negligible. In line with the counterfactual simulations presented in Section 7, a waiver of the minimum price provision is documented in the table.

Waiving the minimum price provision in the QatarGas sales contract leads to lower mean NPVs of cash flows in the two accounts because the minimum price level is higher than the mean oil price underlying the simulations. Government NPV of cash flows falls to $ 2608 million, foreign partner cash flows falls to $ 329 million, the minimum price provision is therefore worth almost $ 1 bn in NPV profits in the oil price scenario used here, and the foreign partners suffer relatively heavier losses from the lower revenues associated with the minimum price waiver than the government because of the high percentage of gas and NGL revenues in its account. In the sample, 20.1 per cent of foreign partner NPVs of cash flows are below zero. The waiver of the minimum price provision reduces government and foreign partner cash flows by about $ 600 million, while greatly increasing risks as shown in Section 5.5.

**Table A 2: Cash Flow Summary Statistics for QatarGas**

| | *Base Case* | | *No Min. Price* | |
|---|---|---|---|---|
| | *Gov.* | *For.* | *Gov.* | *For.* |
| Mean | 3042 | 563 | 2608 | 329 |
| Lower | 2710 | 433 | 1938 | 30 |
| Upper | 3553 | 780 | 3375 | 670 |

Note: NPV of cash flows in $ millions for QatarGas, government (Gov.) and foreign partner (For. Partn.) accounts, first two columns actual projected amounts, next couple with a simulated waiver of the minimum sales price provision in the QatarGas sales contract.

## RasGas

The purchase and sales contracts with the RasGas company do not specify a minimum price and sales are based on the Omani conversion factor, so low oil prices therefore mean low LNG sales receipts, similar to the scenario simulated for QatarGas. In addition, the production volume of RasGas is much lower than in QatarGas and the former therefore lacks benefits from economies of scale. Nevertheless, the sales price formula for RasGas is much more favourable than for QatarGas and investment costs for the second Qatari venture are well below those of the older plant. The mean NPV of total cash flows is therefore almost equal to the base figures in the QatarGas venture. Table A3 shows summary statistics for the probability distributions for the two accounts in RasGas.

Mean government NPV of cash flows is $ 2969 million, about the same as the expectation from the QatarGas base figures. The NPV of foreign partner cash flows in RasGas is $ 715 million, significantly higher than in QatarGas. The lower range figure for RasGas is $ 482 million, with a negligible probability of negative cash flows.

**Table A 3: Cash Flow Summary Statistics for RasGas**

| | *Governm.* | *For. Partn.* |
|---|---|---|
| Mean | 2969 | 715 |
| Range Lower | 2416 | 482 |
| Upper | 3599 | 983 |

Note: NPV of cash flows in $ millions for RasGas, government (Gov.) and foreign partner (For. Partn.) accounts.

## OmanLNG

With the strong position of the government in the upstream section of the project the government cash flows from OmanLNG are relatively high given the high sales price formula, and although no minimum price provision was agreed with the buyers. As shown in Table A4 mean NPV of government cash flows is $ 3403 million whereas the foreign partners expect to receive $ 1758 million. The downward risk for the government account is low with a lower range value of $ 2595 million. The chance of having negative NPV of cash flows in the foreign partner account is negligible, the lower range NPV of cash flows is $ 1375 million.

The second part of Table A4 shows NPVs of cash flows for the counterfactual simulation shown in Section 7.2. Mean values are shown for government and foreign partner cash flows with a sales volume for OmanLNG of only 4.8 mt per year instead of the full capacity production of 6.6 mt. The table shows that NPV of government cash flows is reduced to $ 1836 million, whereas foreign partners receive $ 934 million. These figures are still high, especially for the foreign partners, who are protected by the service agreement with fixed return on investment in the upstream section. A reduction of sales volumes by one third leads to a reduction in NPVs of about half the original value.

**Table A 4: Cash Flow Summary Statistics for OmanLNG**

| | *OmanLNG, base case* | | *Reduced Volume* | |
|---|---|---|---|---|
| | *Governm.* | *For. Partn.* | *Governm.* | *For. Partn.* |
| Mean | 4187 | 1415 | 1836 | 934 |
| Range Lower | 3375 | 1023 | 1372 | 647 |
| Upper | 5156 | 1845 | 2385 | 1251 |

Note: NPV of cash flows in $ millions for OmanLNG, government (Gov.) and foreign partner (For. Partn.) accounts.

**YemenLNG**

Table A5 presents results for Monte Carlo simulation of the NPV of cash flows in the government and foreign partner accounts of YemenLNG. The mean NPV of government cash flows is $ 2389 million, the foreign partner account on the other hand receives a mean NPV of cash flows of $ 3381 million and the probability distribution in Figure 6 is nearly symmetric. YemenLNG is the most profitable project for the foreign partners.

**Table A 5: Cash Flow Summary Statistics for YemenLNG**

| | *Gov.* | *For. Partn.* |
|---|---|---|
| Mean | 2389 | 3381 |
| Lower | 2026 | 2507 |
| Upper | 2820 | 4390 |

Note: NPV of cash flows in $ millions for YemenLNG, government (Gov.) and foreign partner (For. Partn.) accounts.

# 1. INTRODUCTION

Natural gas is increasingly the energy source of choice because of convenience, high thermal efficiency, and relative cleanliness when compared with oil or coal. Because of its gaseous nature transport poses a major obstacle to a more thorough penetration of world-wide energy markets. This obstacle can be overcome by long-term investments in transport infrastructure. This paper looks at projects designed to overcome the geographical limitations of the utilisation of Middle Eastern natural gas: the latest four Liquefied Natural Gas (LNG) projects in the region.

LNG projects require high capital investments and operate in an uncertain environment. Prices are mostly set by bilateral purchase and sales agreements in an imperfect market environment. Mutual trust and dependability over a long time horizon are paramount. In addition, sales prices have so far mostly been linked to the highly volatile world oil price. This link to oil prices has become stronger over time, as floor and ceiling prices have disappeared. The volatility of prices is therefore of increasing concern for LNG investors. Investors have to be convinced that the economics of a proposed venture are robust enough to service long-term debt and afford an adequate return on equity investment.

This study looks at the determinants of this robustness. We look at financial details and risks of LNG projects by simulating cash flows, using benchmark data on sizes, costs, external finance, fiscal regimes, ownership structures, and sales prices. Three aims are central to the analysis:

- To quantify the contributions of different parts of the projects to success or failure. The paper looks at the contribution of project finance and Natural Gas Liquids (NGL) sales to increasing the profitability of the projects, and the effects of fiscal regimes and ownership arrangements on the sharing of returns.
- To quantify the effects of project finance, fiscal regimes, and ownership arrangements on the exposure of investors to risks. The paper simulates the variability of LNG project cash flows in an uncertain world using probabilistic prices and costs. The results are interpreted in terms of increasing or mitigating risks, and risk sharing between joint venture partners.
- To develop unit costs and minimum supply prices for LNG based on actual project details, including NGL revenues, finance, fiscal regimes, and ownership structures. These minimum supply prices show LNG competitiveness in potential markets.

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