# Risk Analysis in Oil and Gas Projects: A Case Study in the Middle East

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SUBMITTED TO MIT- SLOAN SCHOOL OF MANAGEMENT & SCHOOL OF ENGINEERING
IN PARTIAL FULFILLMENT OF THE REQUIREMENTS
FOR SYSTEM DESIGN AND MANAGEMENT PROGRAM
FOR THE DEGREE OF



MASTER OF SCIENCE IN ENGINEERING AND MANAGEMENT

AT THE

MASSACHUSETTS INSTITUTE OF TECHNOLOGY



JANUARY 2009



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## Abstract

Global demand for energy is rising around the world. Middle East is a major supplier of oil and gas and remains an important region for any future oil and gas developments. Meanwhile, managing oil and gas projects are becoming more challenging and riskier than ever before. Therefore, risk analysis and development of strategies to manage risk are crucial to the reduction of potential future delays and cost overruns in oil and gas projects.

This thesis focuses on analysis and management of the technical and institutional risks involved in oil and gas projects in the Middle East. In the first section, we describe various types of risk and introduce a framework for risk management. We then conduct a case study to highlight some of the most important risk factors involved in oil and gas projects as well as recommendations to deal with such risks. The case is based on publically available information and includes two distinct projects with similar geologies under two separate legal regimes in Iran and Qatar.

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# Acknowledgements

I would like to thank my thesis advisor Professor Donald Lessard at MIT Sloan School of Management who guided me and made this work possible. It has really been a great pleasure and honor for me to work with Professor Lessard.

I am also extremely grateful to BP for providing funding for this research.

The System Project Management course taught by Professor Olivier de Weck at MIT Engineering Systems Division was a great source of inspiration to me and helped me think critically with respect to management of large engineering projects. Therefore, I am very thankful to Professor de Weck as well.

Accessing information of oil and gas projects has always been a challenge. The author is profoundly indebted to Capitan Shahriar Sasanian in National Iranian Tanker Company, Mr. Majid Boroumandzadeh in Iranian Offshore Engineering and Construction Company and Ms. Shirin Tahery in Karafarin Bank for helping to gather information about South Pars projects in Iran.

Finally, I would like to express my thanks to my family for enabling me to reach this point in my life.

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# Chapter 1 Introduction

## 1.1 Motivation

Demand for energy is rising around the world. According to International Energy Agency (IEA), global energy demand will grow at a rate of 1.6% until 2030. The main driver behind this growth is increasing power generation and transportation needs. Global demand for energy will be met by various types of energy as shown in Figure 1. In 2030, fossil fuels will account for 80% of the energy mix, with oil and gas contributing close to 60%. [1]

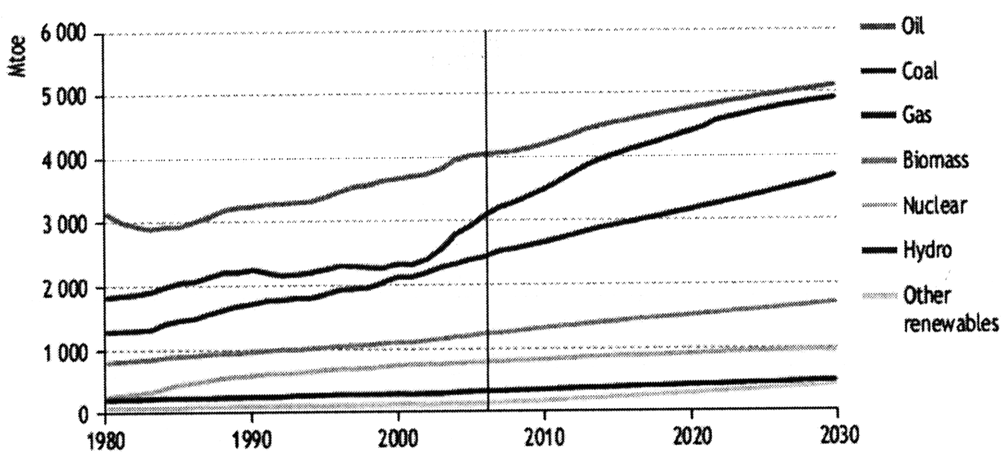


**Figure 1: World Energy Demand by Fuel, Source: IEA World Energy Outlook 2008**

Middle East, is a major supplier of oil and gas (Figures 2 and 3) and thus remains an important region for any future oil and gas developments. Meanwhile, managing oil and gas projects are becoming more challenging and riskier than ever before. Therefore, risk analysis and development of strategies to cope with risks are crucial in order to reduce potential future delays and cost overruns in oil and gas projects.

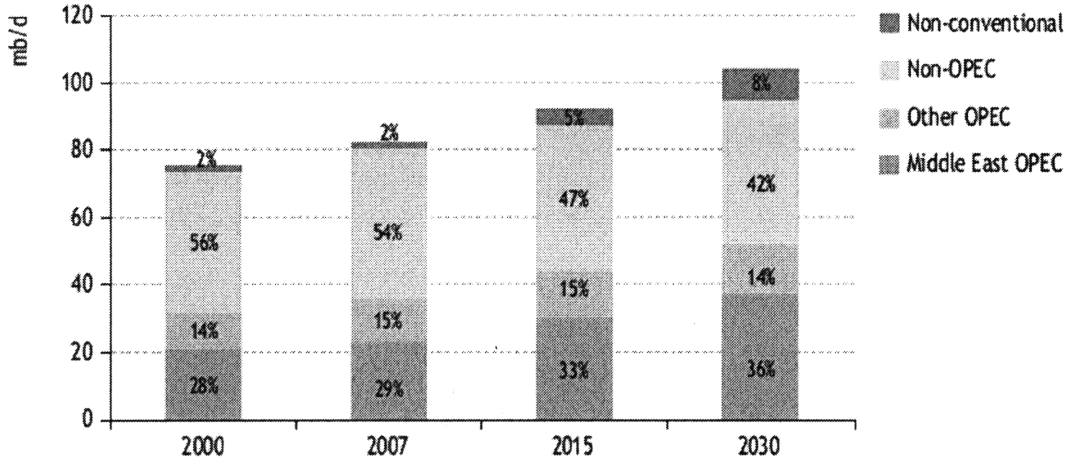


**Figure 2: Oil Production by Region, Source: IEA World Energy Outlook 2008**

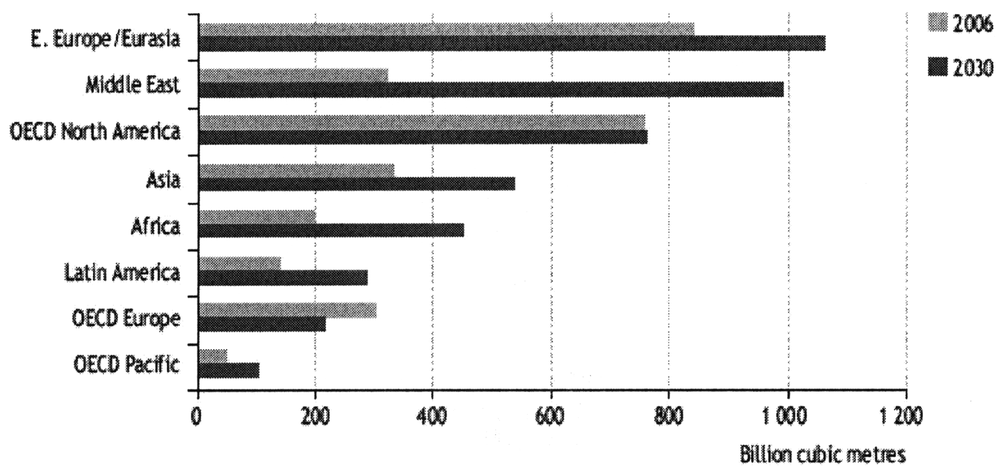


**Figure 3: Natural Gas Production by Region, Source: IEA World Energy Outlook 2008**

In this thesis, we will conduct a case study of risk analysis for oil and gas development in the Persian Gulf. The case is based on publically available information and includes two distinct projects with similar geology under two separate legal regimes in Iran and Qatar. Our qualitative discussion highlights some of the most important risk factors involved in oil and gas projects as well as recommendations to deal with such risks. It is important to note that this study does not cover market related risks because such research requires access to proprietary corporate information.

## 1.2 Background Information

Before we start the case discussion in chapter 2, we will provide background information about risk analysis in this section. Our background section has three parts: In the first part, we define risk. In the second part, we categorize various types of risk in large engineering projects (LEPs). Finally in the third section, we introduce a risk management framework and describe strategies to cope with risk.

### *Definition of Risk*

According to Merriam-Webster, the word "Risk" is derived from the French word "risque" and Italian word "risco" and its usage goes back to $17^{th}$ century. [2] There are many definitions of risk that vary by specific domain and context. In the most general terms, risk is described as situations or the resulting impact of events that unfold negatively. However, in some domains such as financial engineering risk includes both potential worse-than-expected as well as better-than-expected situations. In the case of hazards or accidents, quantitatively, risk is defined by probability of an accident multiplied by loss associated to that accident.

Some people also distinguish between uncertainty and risk. According to Douglas Hubbard, uncertainty is the lack of complete certainty and characterizes situations in which potential outcomes are not known. For example, in January 2009 the winner of 2010 FIFA World Cup is not known and the situation represents an uncertainty. On the other hand, risk is an uncertainty that some of the possibilities involve a loss. For example, there is a 30% chance that a proposed oil project in the Caspian Sea fails and stakeholders incur a loss of $100 million. [3]

### *Categories of Risk*

LEPs such as development of oil and gas fields are risky and subject to cost overruns and delays. We can bundle the risks faced by these projects into three broad categories: Market related risks, Technical risks and Institutional risks. [4]

#### Market Related Risks

**Market Risks:** Market risks are related to the ability to forecast the quantities and prices of goods and services produced by LEPs. This risk varies with the type of the projects. In the case of LEPs that produce specific localized services such as airports, bridges, or high-speed rail lines, actual demand differs from initial assumptions and this could put LEPs at risk to survive. In the case of oil and gas projects that produce internationally traded products, particularly crude oil, they face the vagaries of commodity markets with often intense price fluctuations. Some oil and gas projects face both kinds of uncertainty, price uncertainty for traded outputs and demand uncertainty for locally-bound products, such as gas that requires a dedicated transport network.

**Supply Risks:** Supply risks are related to uncertainties involved in price and availability of necessary inputs to LEPs. For example, in oil and gas projects, dedicated drilling rigs, heavy lift vessels as well as commodities such as cement, pipe and steel and skilled labor are key to construction efforts.

**Financial Risks:** This refers to risks involved in attracting investors and moving forward with a project, as well as changes in financial terms. An increase in credit spreads, for example, could jeopardize a project located in a risky region. This type of risk should not be confused with a scenario in which initial feasibility studies show no prospect for future success. Financial risks also include inability to restructure financial arrangements in the event of unexpected changes in the cash flows.

## Technical Risks

**Technological Risks:** LEPs face a verity of technical risks reflecting their design or the limitations of the underlying technologies.

**Construction Risks:** These are the challenges contractors and sub-contractors face when building LEPs and the resulting uncertainties regarding cost (Capex) and schedule. The sources of such risks could be different depend on the circumstances. Sometimes, contractors bid aggressively underestimating the underlying geological conditions or simply lack the experience to deliver the agreed upon obligations. Safety issues can also become a major obstacle in fulfilling contract commitments.

**Operational Risks:** In some cases after the construction is finished, the equipment does not work as it should. This may be due to lack of investment in quality control systems from the beginning, especially in the case of projects involving new technology and/or in new regions, or the lack of experience of operators.

## Institutional Risks

**Regulatory Risks:** The property rights associated with each project are defined by the legal regime in each country, but the specific terms are defined by contracts that reside within these regions. Regulatory risks are mostly related to delays in obtaining licenses and restrictions attached to such licenses by the regulatory body. These risks are greater in underdeveloped countries in which institutions do not work within constitutional frameworks as in developed nations.

**Social-acceptability Risks:** Sometimes sponsors face opposition from the public for new projects. A good example is pressure from local community against building a nuclear power plant due to concerns about treatment of nuclear wastes.

**Sovereign Risks:** This refers to cases where government abrogates or renegotiates the terms of agreed contracts. Such scenarios usually happen because of political shifts such as regime changes and economic changes. An example of contract renegotiation took place during Iran's oil nationalization movement in the early 1950s when government of Iran requested changes to the terms of agreement with Anglo-Persian Company.

### *Dynamic Interactions of Risks*

LEPs face not only the risk categories mentioned in the previous section, but also the compound risks resulted from dynamic interaction of individual risk categories. In some cases, the compound risks can have huge impact on projects and make them ungovernable. A delay in obtaining licensing (institutional risk) can postpone the commissioning and start up phase of an LEP. This in turn, can potentially put the project under financial risk as the projected revenue streams are further pushed out.

### *Risk Management*

There is no doubt that stakes in LEPs are huge. Therefore, proper risk management techniques are necessary to make LEPs successful. Figure 4 illustrates one commonly used framework for managing risks in projects. [5]

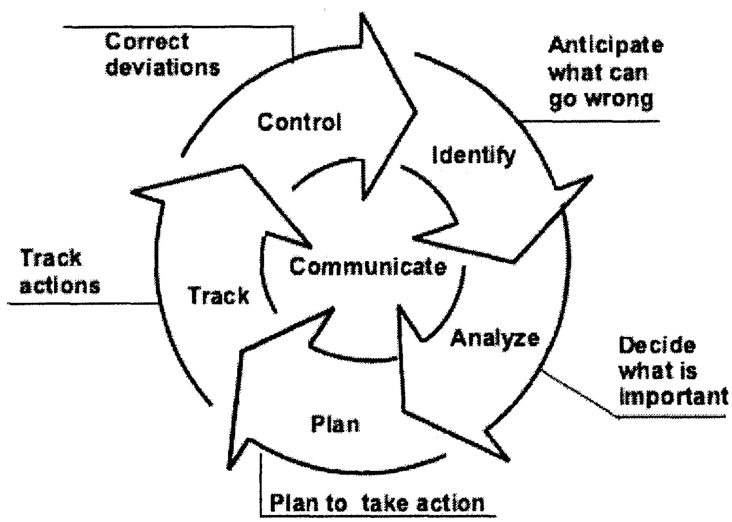


**Figure 4: Framework for Risk Management**

The framework suggests identifying risks and analyzing them as early as possible in the project life cycle. The process usually includes finding the sources of risks, the severity of each risk and the dynamics between various sources of risks. Based on the result of analysis, an action plan must be developed. The actions fall into four broad categories which will be explained in the next section: Avoidance, Mitigation, Transference and Embracing. Finally, project managers should incorporate a tracking mechanism and correct any deviations from the set targets. The model also advocates an effective communication mechanism among all the stakeholders during the entire project period in order to successfully implement this framework.

### *Strategies to Cope with Risk*

Once risks are identified and assessed, there are four major strategies to deal with them. In subsequent sections we describe each of the strategies.

**Avoidance:**

In some cases, expected losses outweigh the potential benefits. In such scenarios the most reasonable option is not to perform the risky activity.

**Mitigation:**

When risks are endogenous- that is specific to the project and controllable- the best approach is to mitigate the risk by shaping the project. For example the parties involved in the project can establish partnership with suppliers, develop flexible/ modular technical solutions and change rules and regulations in order to shape the outcome of the project and mitigate risks. Diversification can also be considered a special form of risk mitigation in which the risk associated with one security is reduced by forming a portfolio of securities.

**Transference:**

In some situations, risks are outside the control of one party but another party is willing to take that risk for a premium. Insurance and hedging are prime examples of transferring risks. For example people by home insurance to protect their houses from natural disasters.

**Embracing:**

Sometimes, the risk cannot be avoided, mitigated to stakeholder's advantage or transferred to others. Seasoned managers know when to embrace the risk of ownership and take advantage of the upside gain. Typically, comparative advantage of firms in embracing the risk comes from their domain expertise and ability to control the consequence of events or from their financial prowess (market capitalization, access to capital market and financial diversification).

Figure 5 illustrates the relation of these strategies to two attributes of the risk. The x axis shows the controllability degree of the risk and the y axis represents the scope of the risk: Whether the risk is project specific or broad and impacts a large number of projects.

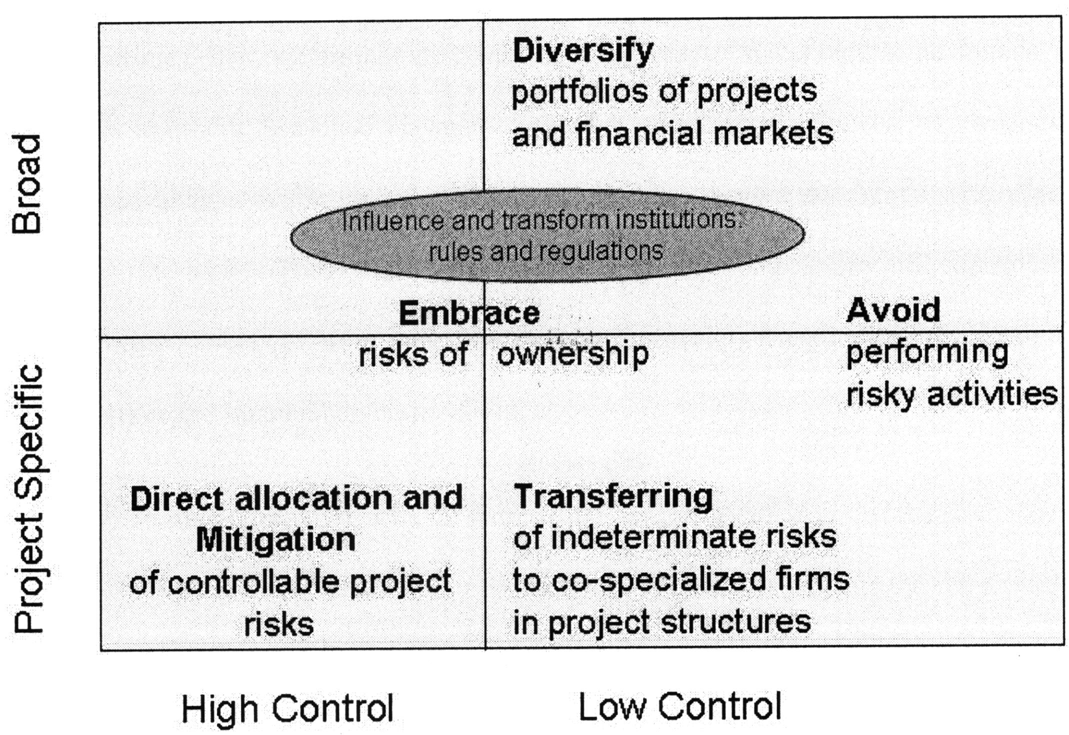


**Figure 5: Strategies to Cope with Risk** [6]

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# Chapter 2 Case Study Analysis

In this chapter, we will do a case study in South Pars/ North Dome field which is shared between Iran and Qatar. Our case involves a project conducted by Pars Oil and Gas Company (POGC) in Iran and a project led by RasGas Company in Qatar. Our objective is to demonstrate the analysis and management of technical and institutional risks in real scenarios. We would also like to show the impact of the risk management strategies on the project outcome. We picked two projects with similar geologies so that when we compare and contrast the risks and associated risk management strategies, the inherent geological characteristics do not become a factor. As a result, the primary difference between the two has to do with technical concepts selection and execution, institutional context and the resulting changes in governance, resulting risks and management strategies.

Before we get into the details of each project, we begin the discussion by giving an overview of the South Pars/ North Filed.

## 2.1 Overview of South Pars/ North Dome Field

The South Pars/North Dome field lies on the territorial border of Iran and Qatar in the Persian Gulf. According to International Agency Organization, it is the largest gas field of the world [1] with 40 to 50 trillion cubic meters (tcm) of reserves and some 50 billion barrels of condensate in place. [7] The gas filed contains significant amount of the world's natural gas reserves considering that at the end of 2007 global proven reserves of natural gas stood close to 180 tcm. [1] The area of the South Pars/North Dome is 9700 square kilometers of which 3700 square kilometers is in Iranian territory and the remaining 6000 square kilometers rests in Qatari territory. Figure 6 illustrates the South Pars/ North Dome in the Persian Gulf.

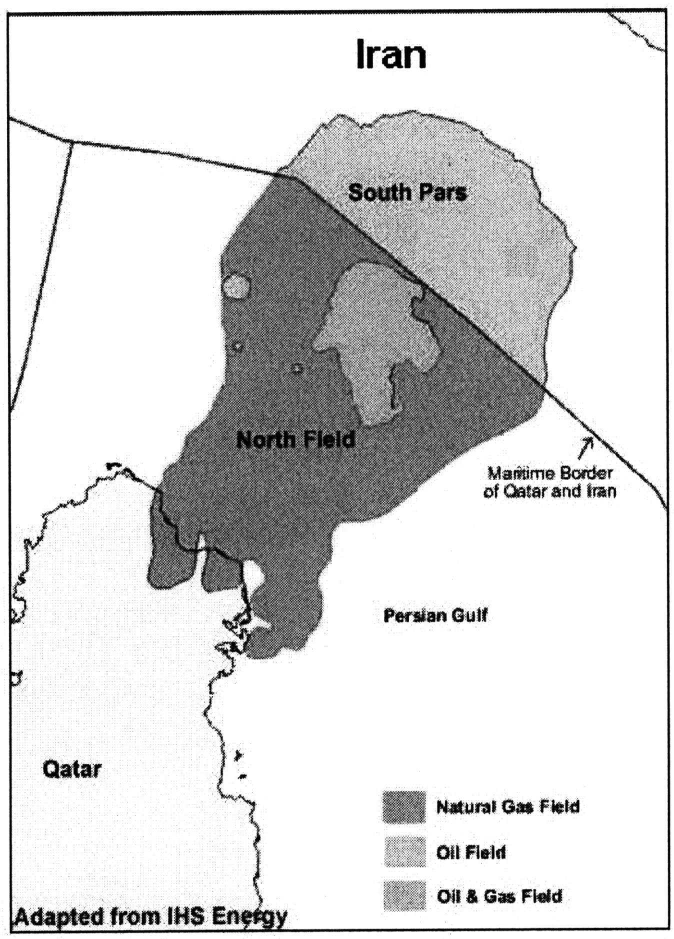


**Figure 6: South Pars/ North Dome Gas Field in the Persian Gulf**

## 2.2 North Dome Development Plan

The North Dome was discovered in 1971 and is estimated to contain 25.5 tcm of natural gas reserves. In order to develop the North Dome, Qatar Petroleum Company formed two joint ventures:

The first joint venture is Qatrgas which was established in 1984. The share holders of this venture are Qatar Petroleum, ExxonMobil, Total, Mitsui, Marubeni, ConocoPhillips and Shell. Qatargas has defined four projects with total of 7 LNG trains. As of the end of 2008, project 1 which has three trains with total production of 10 million tones per annum (mtpa) is finished. By the end of 2010, it is expected that three other projects will be finished and total production of 7 trains reaches 42 mtpa. Qatargas also has the Laffan Refinery Company Limited's plant currently under construction. The plant is expected to start production in 2009, with a processing capacity of 146,000 barrels per stream day (BPSD). [8]

The second venture is RasGas which is established in 1998. The shareholders are Qatar Petroleum (70%) and ExxonMobil (30%). As of the end of 2008, RasGas operates 5 LNG trains with 20.7 million mtpa of production capacity. It is expected that this production will be in the region of 37 mtpa by 2009 with the completion of another 2 trains. [9]

Additionally, to support the exploration, storage and export of gas resources in the North Dome field, government of Qatar established Ras Laffan Industrial City (RLIC) in 1996. The city covers an area of 106 square kilometers and is expected to expand to nearly 250 square kilometers in the near future. [9]

## 2.3 South Pars Development Plan

The South Pars field was discovered as an extension of Qatar's North Dome field in 1990 by National Iranian Oil Company (NIOC). The field is estimated to contain some 14 tcm of gas reserves and some 18 billion barrels of gas condensates. In 1998, government of Iran approved establishment of Pars Special Economic Energy Zone (PSEEZ) to accommodate the South Pars related activities. PSEEZ covers an area of 100 square kilometers and has to two major sites: Site one is in Assaluyeh and Nakhl-e-Taghi and the second site is in Tombak, some 60 kilometers west of Assaluyeh. [10]

Furthermore, in 1998, the Pars Oil and Gas Company (POGC) was established by NIOC to develop the South Pars filed. POGC has defined 24 phases in order to produce 820 million cubic meter of gas per day. The 24 phases include offshore facilities, pipelines to transfer products from offshore facilities to onshore facilities, onshore facilities, gas pipelines to transfer gas to national network and export facilities to export gas condensates, LPG and sulfur. As of the end of 2008, 7 phases are in operation and the rest of the phases are either under construction or study.

In the remainder of this chapter we will concentrate on two specific projects in the South Pars/ North Dome field. The first project is phases 6, 7 and 8 in the South Pars and the second one is the RGX in the North Dome. We gathered all the data for the two projects from public information. However, in the case of phases 6, 7 and 8 project, we resolved some of the ambiguities in the public information by interviewing two experts who had exposure to South Pars projects.

Before we start our risk analysis discussion, we need to give an overview of each of these projects.

## 2.4 Phases 6, 7 and 8 in South Pars

In July 2000, Pars Oil and Gas Company (POGC) awarded the contract for developing phases 6, 7 and 8 to Petropars. Petropars which was founded in January 1998 is owned by Naftiran Intertrade Company, the financial arm of National Iranian Oil Company.

POGC has set the following objectives for the phases 6, 7 and 8: [10]

- Daily production of 104 Mscm of sour and dry gas
- Daily production of 158,000 barrels of gas condensate per day
- Annual production of 1.6 million tons of liquid gas (propane and butane) "LPG" for export.

In order to increase oil production in Aghajari oil field in Khuzestan province of Iran, the sour gas produced in these phases is transferred via a 512 kilometer pipeline to be injected into the oil wells. Later, however, decision was made to transfer some of this gas to meet the domestic gas consumption and as a result a sweetening unit was constructed next to phases 6, 7 and 8.

The project has onshore and offshore sections. The onshore section is located in Assaluyeh in the Booshehr province and the offshore is 105 Km's in the sea of the Persian Gulf. Figure 7 illustrates the onshore and offshore locations of phases 6, 7 and 8.

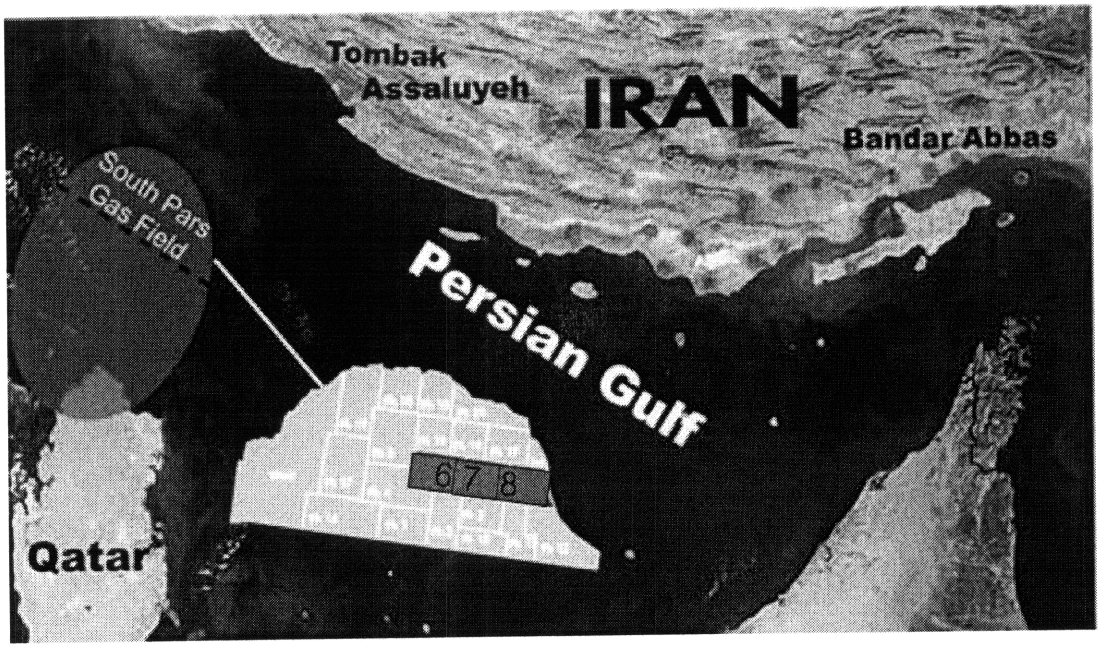


Figure 7: Phases 6, 7 and 8 in South Pars Gas Field, Source: Petropars Company

### *Phases 6, 7 and 8 Onshore Facilities*

The onshore facilities consist of:

- Non-industrial buildings which include all administration, clinic, restaurants and warehouse facilities needed for the operation of onshore refinery.
- A 160 MW gas turbo generator power plant for the onshore refinery
- 100 MVA power transmission line to supply the onshore refinery form a petrochemical plant at the region
- An integrated fiber optic network for onshore and offshore communications of phases 1 to 10
- Onshore sour gas refinery with the capacity of 110 million cubic meter of feed gas including the following units:
    - Reception Facilities
    - High Pressure Separators
    - Gas Dehydration
    - NGL Extraction and Fractionation
    - Export Gas Booster Compressor
    - Condensate Stabilization
    - MEG Recovery
    - Sour Water Stripper
    - LPG Treating Unit
    - Condensate Storage
    - LPG Storage
    - Utilities

- Control System

### *Phases 6, 7 and 8 Offshore Facilities*

The offshore facilities consist of:

- Three appraisal wells (one for each phase) and 27 development wells (nine for each phase)
- Three production platforms. (Each platform consists of two main sections: Jacket and Topside. Each Platform has 10 producer slots and 6 spare slots for future wells)
- Three 32" submarine pipelines for transferring gas to the onshore refinery, length of each of which is about 105 km
- Three 4.5" pipeline for transferring glycol solution
- One single buoy mooring (SBM) terminal for exporting gas condensate
- A 5.4 kilometer 30" pipeline for transferring gas condensate to the SBM.

## 2.5 Phases 6, 7 and 8 Work Allocation to Contractors

One of the key objectives of POGC and Petropars is to develop domestic technical and managerial expertise for executing complex oil and gas projects. Therefore, it is the policy of both companies to allocate substantial share of designing, procurement, fabrication, construction and installation of facilities (offshore and onshore) to domestic companies. The second goal which is related to the previous goal is to accomplish technology transfer through joint-venture agreements between local and foreign companies.

### *Phases 6, 7 and 8 Onshore Task Breakdown* [11]

The non-industrial buildings contract was awarded to Petropars on October 2004; MANA was selected as the contractor for this project.

The power generation plant project for the refinery of phases 6, 7 and 8 was awarded to Petropars on June 2005. Later the project was handed over to the joint venture of Hirbodan and Hico FZE through an Engineering, Procurement and Construction (EPC) contract. The duration of this project was scheduled to take about 20 months.

The integrated fiber optic network for phase 1 to 10 was also awarded to Petropars in addition to the original service contract of phases 6, 7 and 8.

TIJD consortium which includes TOYO of Japan, IDRO of Iran, JGC of Japan and Daelim of Korea was awarded the EPC contract for the refinery on May 2002. Site preparation for the refinery was started on December 2001 and completed on December 2003 by Fater Kosaran Jonoob and Abad Rahan Pars. This project consisted of over 15 million square meters of soil work.

Overall, the entire Capex commitment at the time of contact for the onshore section was $1.15 billion.

### *Phases 6, 7 and 8 Offshore Task Breakdown* [11, 12]

ISOICO an Iranian company was awarded EPC contract for the fabrication and installation of jackets. ISOICO started its activities on July 2002 and completed its work in January of 2004.

Sadra an Iranian company was awarded the EPC contact of topsides, flares, intermediate-bridges, installation of 32" pipelines for a length of 105 Km, single point mooring (SPM) and its connecting pipelines. These activities were performed on Sadra's industrial island in Booshehr.

After Petropars established contracts with the main suppliers to the project including Sadra, the company signed a buyback contract with Statoil, a Norwegian company, in October 2002. Based on the contract, Statoil got 37% and Petropars got 63% of the offshore section of phases 6, 7 and 8. The contract also gave the operatorship of the offshore section to Statoil. The duration of the work expected to take four years. In return, Statoil made a capital commitment of $300 million for the next four year period. Statoil also became responsible for managing jacket, platform and topside fabrications, sub sea piping, SPM and drilling of the development wells. According to the contract, Statoil's capital commitment and return would be covered from sales revenues of condensates and LPG over a four-year period from the start of production which was planned late 2004. We defer the explanation of buyback contracts to the section we discuss about institutional risks.

The total project management of phases 6, 7 and 8 remained the responsibility of Petropars which also oversaw the management of Statoil, the offshore operator. The NIOC would take over as production operator once the development was complete.

Overall, the entire Capex commitment at the time of contact for the offshore section was $750 million.

## 2.6 Project Outcomes in Phases 6, 7 and 8

Phase 6, 7 and 8 has faced severe delays and cost overruns. In January 2006 Statoil announced \$329 million (\$237 million after tax) write down to the book value of its shares in the offshore section of phases 6, 7 and 8. This is despite the fact that drilling operations were finalized 40% faster than budget, saving 775 rig days. [13]

Statoil blamed Sadra for not meeting its commitment for EPC contract of platform topsides, plus the laying of the remaining one of three approximately 100-kilometer-long pipelines from the field to shore. Statoil had to change the plans in order to meet delivery obligations and considered strengthening of management resources and technical expertise at Sadra as well as the possibility of transferring parts of the remaining work to other contractors to complete the project. [13] Statoil became under further pressure when the company faced bribery allegation related to phases 6, 7 and 8. In October 2006, the company announced the settlement of the case by paying a \$7.5 million fine. [14]

In October 2008, phase 6 was officially inaugurated. For phase 7, construction and installation was complete but pre-commissioning and commissioning works in offshore topside were being done and for phase 8, at the time of inauguration there were no topside and subsea pipeline installed. In the other words, at the time of inauguration, onshore refinery plant of all three phases was ready for operation but in the offshore section only phase 6 was ready. By the end of 2008, offshore part of phase 7 was completed and phase 7 was under operation as well as phase 6. For phase 8, as of January 2009, the topside is installed in the Persian Gulf and it's under pre-commissioning. Also

*Solitaire* (famous lay barge of Allseas Co.) is near to finish laying of pipeline of phase 8. So it can be predicted that at most by the end of 2009, phase 8 would be operational.

According to Mr. Manouchehri, Managing Director of Petropars Company, each phase of the project costs $1 billion and including the cost of power plant the total cost of three phases would reach $3.3 billion. This means the project has faced about $800 million cost over run from the estimated $2.5 billion (Capex and Non-Capex) at time of the contract.

## 2.7 RGX Project in North Dome [15]

After successful launch of LNG trains 1 and 2 in 1999, RasGas embarked on an expansion project also known as RGX. The objective of the projects was to produce 4.7 million ton per annum (Mtpa) of LNG from each of the three new LNG trains (Train 3, Train 4 and Train 5).

The project was officially kicked off in year 2000, when RasGas awarded the Front End Engineering and Design (FEED) contract. The project had onshore and offshore sections. The onshore section is located in Ras Laffan Industrial City and the offshore section is in the Persian Gulf.

### *RGX Onshore Facilities*

The onshore facilities consist of:

- LNG Train 3 with production capacity of 4.7 mtpa based on APCI technology

Please note there was no LNG tank necessary for train 3 as the original three tanks installed for LNG trains 1 and 2 was sufficient to handle additional production.

- LNG Train 4 with production capacity of 4.7 mtpa based on APCI technology
- LNG Tank 4 with the capacity of 140 cubic meters
- LNG Berth 3
- LNG Train 5 with production capacity of 4.7 mtpa based on APCI technology
- LNG Tank 5 with the capacity of 140 cubic meters
- NGL recovery from LNG train 4
- Al Khaleej Gas (AKG) project with the capacity to produce 750 million standard cubic feet (Mscf) per day
- LNG Tank 6

### *RGX Offshore Facilities*

The offshore facilities consist of:

- Four wellhead platforms
- Two 38" gas trunk lines
- Two 28" intrafield pipelines

Figures 8 and 9 illustrate RGX facilities in Ras Laffan Industrial City.

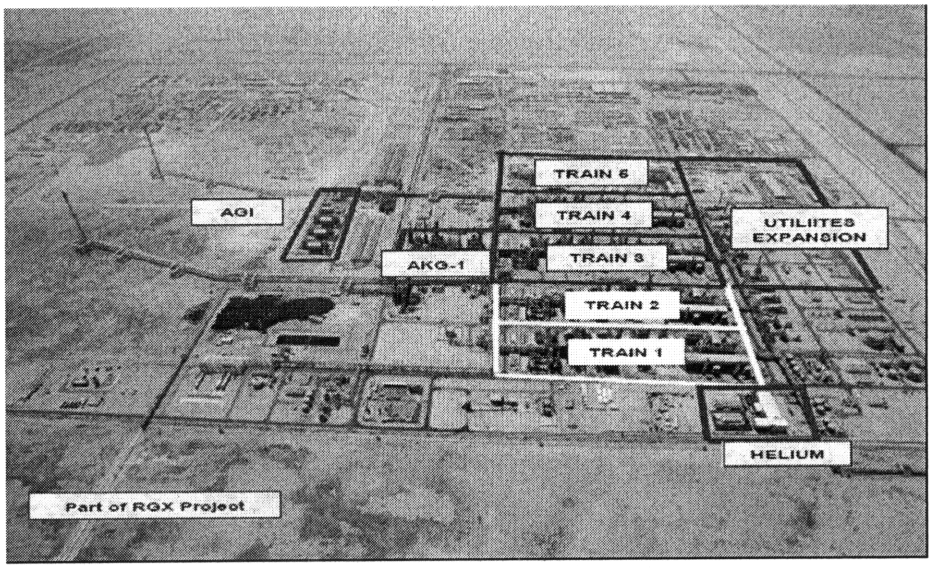


**Figure 8: RGX LNG Trains in Ras Laffan Industrial City** [15]

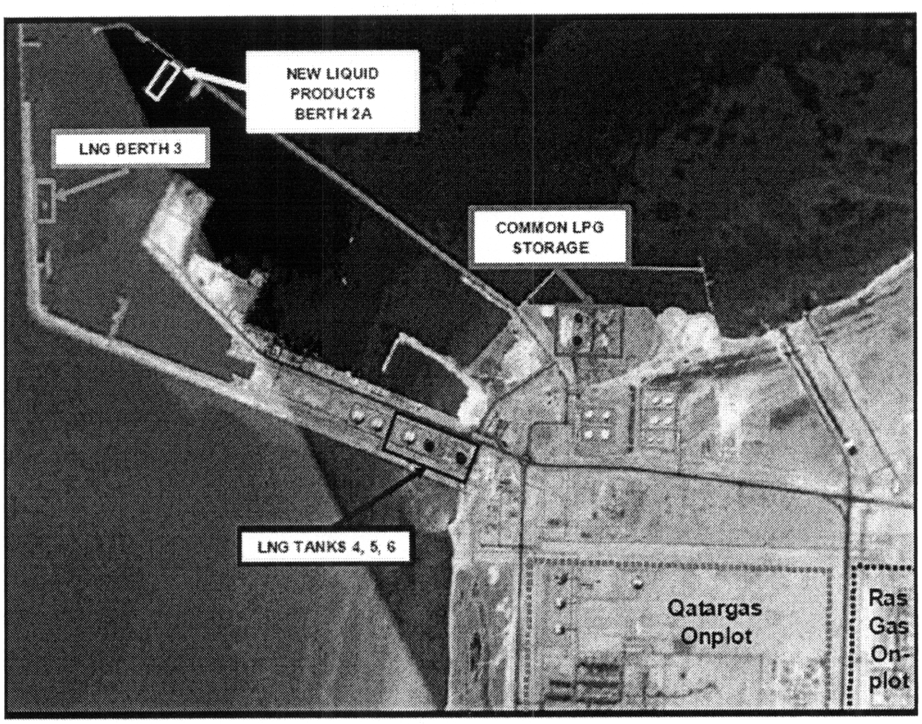


**Figure 9: RGX Facilities in Ras Laffan Industrial City** [15]

## 2.8 Work Allocation to Contractors

The strategy of RasGas was to award multiple projects simultaneously to single set of contractors and replicate the design. The objective of maximization of work to single contractor was to create execution synergies within the contactor's scope of work. Replication was achieved at two distinct levels: design and execution.

At the design level, the following facilities had identical designs:

- LNG Trains 4 and 5
- LNG Tanks 4 and 5
- LPG Tanks and processing facilities within Al Khaleej Gas common LPG storage and loading facility

At the execution level, EPC contactor was able to benefit from replication in the following ways:

- A single project team was used for the entire 6 years of EPC work
- The key sub-contactors and vendors were maintained during the entire period
- Facilities to support construction was shared throughout the project
- Minimum rework for delivering same engineering work
- Optimal resource allocation from one facility to another by careful sequencing of engineering and construction activities
- Uses of options during LNG train 3 purchase order for additional identical equipments for future plants.

In 2001, RasGas awarded the EPC contact of the onshore section of RGX project to a join venture of Chiyoda Corporation, Snamprogetti, Mitsui and Al Mana W.L.L (CMS&A). The contract had a base scope and an option work. The base scope included LNG train 3. The Option work included the rest of the items listed under the previous *Onshore Facilities* section. Ultimately, the option work was also executed by CMS&A.

The EPC contact of the offshore section was given to J. Ray McDermott.

## 2.9 RGX Project Outcomes

Replication in design and execution and awarding the project to a single contractor resulted in very positive outcomes for the project. Below, we summarize the results in terms of reduction in cost and schedule as well as improvements in project safety and quality.

- **Cost Reduction:** We do not have data for the dollar savings but we know that there was 30% reduction in unit cost from train 3 to train 5. At least three sources contributed to the cost savings: Replication of design reduced engineering man-hours for LNG train 5 to 30% of engineering man-hours of LNG train 3. Additional purchasing power was gained when initial commitment was made for resources and equipment needed for train 3. Productivity increased by optimizing repetitive tasks.
- **Schedule Reduction:** Project duration defined from the time EPC awarded until mechanical acceptance reduced from 36 months for train 1 and 2 to 33 months for train 3 and 4 and 28 months for train 5. Design and execution plan replication contributed to schedule reduction by reducing the critical path engineering activities,

minimizing changes and rework and retention of key subcontractors during the project.

- **More Effective Commissioning & Start-Up:** Completion of similar projects within a short period of time contributed to effective commissioning and start-up of projects. Train 5 and Al Khaleej started 20 and 24 days after completion compared to 38 and 51 days for train 3 and train 4.
- **Continuous Safety Improvement:** RasGas had an excellent safety record on LNG train 1 and 2 but RGX achieved even a better safety year after year. Using total recordable injury rate (TRIR) as a measure, safety improved by 10% in 2004 compared to 2003. It reduced by one half in 2005 and by another one half in 2006. The resulting TRIR was over 6 times lower than 5 year (2001-2005) industry average for oil and gas producers in the Middle East.
- **Continuous Quality Improvement:** Similarities between train 3 and the subsequent phases of RGX led to continuous quality improvement of the RGX. Figure 10 illustrates the quality improvement between train 3, train 4 and Al Khaleej Gas projects by comparing warranty claims, lessons learned, technical queries and other improvements.

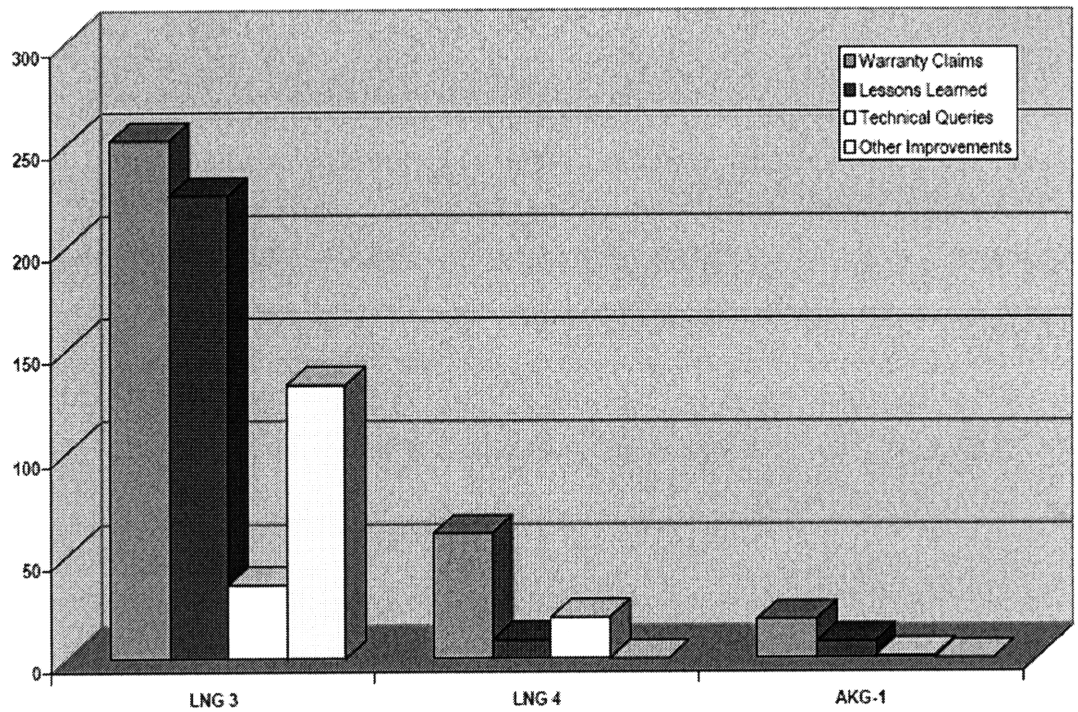


**Figure 10: Comparison of Quality Improvement across Projects** [15]

## 2.10 Risk Analysis

In this section we will conduct a risk analysis discussion for phases 6, 7 and 8 in the South Pars and RGX project in the North Dome. We follow the same risk management framework we described in chapter 1 (Figure 4) for our analysis: First we identity the sources of risks and analyze the significance of them in each project. Then we evaluate the strategies adopted by stakeholders to cope with such risks. Throughout our discussion, we will concentrate on two categories of risk: Technical and Institutional.

### *Technical Risk Analysis*

As we recall from chapter 1, technical risks are divided into three sub-categories: technological risks, construction risks and operational risks. In subsequent sections we will compare and contrast the two projects with respect to each of these risks.

**Technological Risks:**

In phases 6, 7 and 8 the required technology for both offshore and onshore facilities was very well known at the time of the project. Therefore, the technological risk was very limited. In contrast, in the case of the RGX project, the design was based on a very innovative solution and at the time was the world largest capacity LNG train in the world. Based on the risk management strategies discussed in chapter 1 and illustrated in Figure 5, we can say that the technological risk of RGX was specific to the project and quite highly controllable. As a result, RasGas was able to mitigate the risk by shaping the project. The shaping strategy adopted by RasGas in this instance was three fold: replicating the design and execution, giving the project to a single contractor and creating option in the contact. The replication of design and execution limited the scope of technology uncertainty. In other words, the technical challenges and solutions to them would be identical for all the trains. Awarding the contract to a single contactor facilitated applying the technical lessons learned in the first LNG train to the future ones. Furthermore, incorporating an option in the contract would prove the credibility of underlying technology and the capacity/performance of the contractor before moving to the next stage.

**Construction Risks:**

In phases 6, 7 and 8 Petropars was facing risk related to the construction of onshore and offshore facilities. At the same time, the company had the mandate to maximize domestic participation in the project. Local contractors had limited managerial and technical capability for the execution of the project. Thus, construction risk would be exacerbated by choosing the local contractors.

The strategy of Petropars to manage the construction risk was to shift the indeterminate risks to firms specialized in such projects. Specifically, Petropars gave the responsibility of executing the offshore project through a contract to Statoil while keeping Sadra as the sub-contactor for the topsides and laying pipes. The same approach was replicated for building the refinery in which the contact was awarded to a consortium of TOYO of Japan, IDRO of Iran, JGC of Japan and Daelim of Korea. On the other hand, from the perspective of Statoil, TOYO, JGC and Daelim with global operations the construction risks in these projects were idiosyncratic and these companies could minimize the risk by diversifying the portfolio of projects they were undertaking at that point in time. Diversification is an effective strategy to minimize the overall risk at the corporate level. But diversified companies still need to manage risk at the project level. Statoil failed to achieve the principles of risk management framework which we discussed in chapter 1 with respect to its share in the offshore section of phases 6, 7 and 8 in the South Pars. The company, should have identified, analyzed and planed for the construction risks associated with Sadra's deliverables in the offshore section of the project at the early stage of the project. One way to accomplish this goal was to launch a FEED activity in order to develop a robust design similar to what RasGas did.

In the case of RGX, RasGas was free to use domestic or foreign contactors for the project. But in order to reduce the construction risks; they awarded the onshore and offshore sections to single contractors and created options in the contract. Awarding the contract to a single contactor facilitated applying the execution lessons learned in the first LNG train to the future ones and therefore reduced the construction risk. Furthermore, incorporating option in the contract would give assurance to RasGas about execution capability of the contactor before moving to the next phase of the project.

**Operational Risks:**

After commissioning and start up, NIOC and RasGas became the operator of facilities in phases 6, 7 and 8 and RGX respectively. Both of these companies had substantial managerial and technical expertise for operating onshore and offshore facilities. Therefore, we believe operational risks involved in the two projects were significantly mitigated.

### *Institutional Risks Analysis*

According to the discussion in chapter 1, institutional risks are divided into three sub-categories: regulatory risks, social acceptability risks and sovereign risks. In subsequent sections we will compare and contrast the two projects with respect to each of these risks.

**Regulatory Risks:**

The legal regime in each country defines the property rights and contracts associated with each project. South Pars projects are awarded based on buyback contracts, but North Dome is developed under production sharing contracts. Before we discuss the risks associated with buyback and production sharing contracts, we need to describe the main features of each contract.

**Production Sharing Contracts:** [16]

Production sharing contracts have been adopted in various forms by different countries. Thus, in the following discussion we will focus on the basic principles underlying these agreements. In production sharing contracts the state draws on the financial and technical skills of the IOC to develop the field. In these types of contracts, the state holds the rights to the hydrocarbon reserves and the IOC works only as the contractor. After the field is developed, the IOC has the right to recover its development cost by appropriating a portion of the annual production known as cost oil. There is usually a maximum limit on the cost oil known as cost stop. The cost stop varies depending on the country and contract terms but is typically 30% to 60% of annual production. In cases in which IOC remains the operator of the field, the recovery cost also includes the ongoing operating costs as well. The proportion of the oil left after cost oil is known as profit oil and split between the state and IOC according to a predefined formula in a contract. The production sharing agreements also have provisions for treatment of taxation which is beyond the scope of our study. Figure 11 illustrates a simplified version of revenue breakdown in a product sharing contract based on 50 -50% split between IOC and the state.

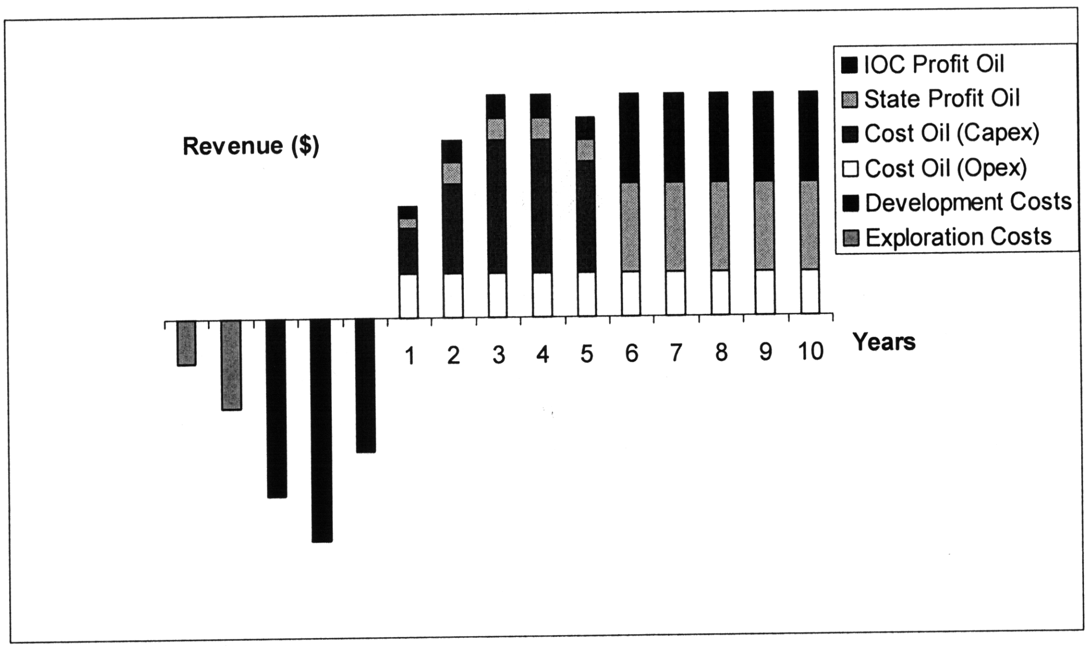


**Figure 11: Oil Revenue Breakdown under a Production Sharing Contract**

**Buyback Contracts:** [17]

Buyback contracts which were first introduced in Iran, aimed at securing the state's sovereignty over its oil and gas resources. Under buyback agreements, an International Oil Company (IOC) provides funding and develops the oil and gas fields on behalf of and in the name of NIOC. In return, NIOC reimburses the IOC through direct sales of resulting products or by payment of proceeds generated from selling the products. According to buyback contracts, IOC work as the contractor for NIOC and not as a partner. Once the project is developed, the operation is handed over to NIOC. In some cases like the phases 6, 7 and 8 in South Pars the buyback contract is awarded to a joint venture of IOC and a domestic company. In such scenarios each partner is jointly and severally responsible to NIOC for financing and developing the project.

Before a buyback contract is awarded, a master development plan (MDP) is generated based on exploratory activities. The MDP defines in details, the scope of work needed for developing the field. According to the buyback contract, the IOC has the legal obligation to implement the MDP and any deviation from MDP requires approval of the NIOC. As a result, buyback contract requires IOC and NIOC to agree on the details of the development at the time of contracting.

**Fiscal Regime in Buyback:**

As we explained in the previous section, IOC is responsible for funding the entire project. Four categories of funding are conceived in a buyback contract:

- Capital costs (Capex)
- Non-capital costs (non-Capex)
- Operations Costs (Opex)
- Bank charges

Capex refer to all costs directly related to development plan specified in the contract. Non-Capex refers to costs difficult to specify at the time of contract such as taxes, social security and custom duties. Opex are costs incurred during commissioning and start up before handing over the field completely to NIOC. Bank charges refer to financing cost which is equal to London Interbank Offered Rate (LIBOR) plus a defined percentage (e.g. 0.75%). Once the objectives of the MDP have been met, these four categories of costs are recovered. Capex is reimbursed up to the ceiling fixed in the contract. So any cost overrun to implement the MDP shall be borne by IOC. There is no cap for non-Capex, Opex and bank charges and they will be recoverable. In addition, a fixed amount referred as remuneration fee will be agreed to be paid to IOC in return for its investment and risks taken. Capex, non-Capex, bank charges and the remuneration fee will be amortized in equal monthly payments over a certain number of cost recovery years as specified in the contract (usually 3 to 5 years). Opex has priority over other costs and is recovered in the quarter following that in which the cost was incurred. In buyback contracts, the cost and remuneration fee are recovered by allocating a percentage of the project output. This is usually 50% to 60% of total production. Figure 12 illustrates a simplified oil revenue breakdown under a buyback contract similar to phases 6, 7 and 8 in South Pars with four years of development period and four years of cost recovery period.

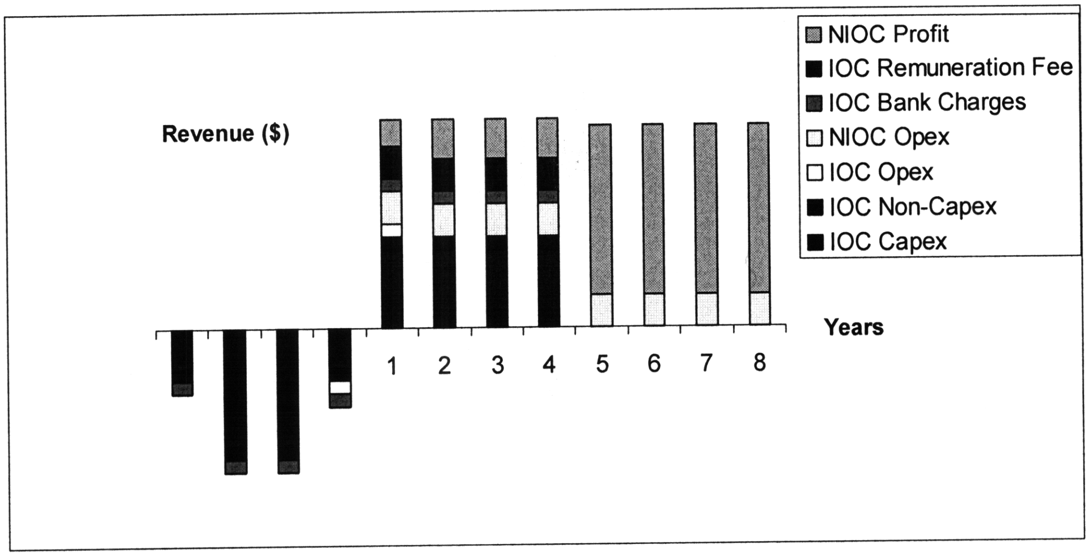


**Figure 12: Oil Revenue Breakdown under a Buyback Contract**

## Comparison of IOC's Pay off in Production Sharing and Buyback Contracts

In this section we would like to highlight the differences between the IOC's pay off for a given development project under buyback and production sharing contracts. We try to explain the differences through a hypothetical project implemented based on buyback and production sharing agreements similar to phases 6, 7 and 8 and RGX.

Suppose we have an LNG project for daily production of 50 Mscm or equivalent of 1765 Mscf. We assume that project duration until first production ($T_{Project}$), price of LNG ( $P_{LNG}$ ) and consequently annual revenue ( $R_{LNG}$ ) have normal distributions :

$T_{Project} \sim N$ (4 Years, 1 Year$^2$)

$P_{LNG} \sim N$ (\$4.67 /thousand scf, \$$^2$4.17) ⇨ $R_{LNG}$ (\$3 billion, \$$^2$1.73 )

We also make the assumption that the expected Capex ($C_{Project}$) for the project is \$5 billion. It is estimated that the project needs additional \$1 billion for non-Capex charges,

\$200 million for bank and financing charges, \$150 million during commissioning and start up. This will bring estimated total cost ($TC_{Project}$) of the project to \$ 6.35 billion. After the production starts, a \$150 million is needed annually to run the facilities. If we assume normal distribution for $C_{Project}$, $TC_{Project}$ will follow a normal distribution as well:

$C_{Project} \sim N$ (\$5 billion, $\$^2$ 1 billion) $\Rightarrow$ $TC_{Project} \sim N$ (\$6.35 billion, $\$^2$ 1 billion)

Now, we consider a scenario that that IOC enters a buyback contract with a four year recovery period, Capex ceiling of \$ 5 billion and remuneration fee of \$ 800 million. The contract also limits the IOC cost recovery to 60% of the total production.

The annual Capex recoveries (ACR) for year 1 to 4 is approximately 50% of the annual revenue ($R_{LNG}$) less the non-Capex, bank charges, Opex and remuneration fee; thus ACR follows a normal distribution:

$ACR \sim N$ (\$1.25 billion, $\$^2$ 0.4325 billion)

The annual Capex recoveries from year 1 to 4 are independent from one another. If we add the independent normal variables and apply the maximum \$5 billion Capex ceiling, the total four year IOC recovery (TCR) distribution will look like half of a bell curve with mean of \$ 5 billion and variance of $\$^2$ 6.92 billion (Figure 13).

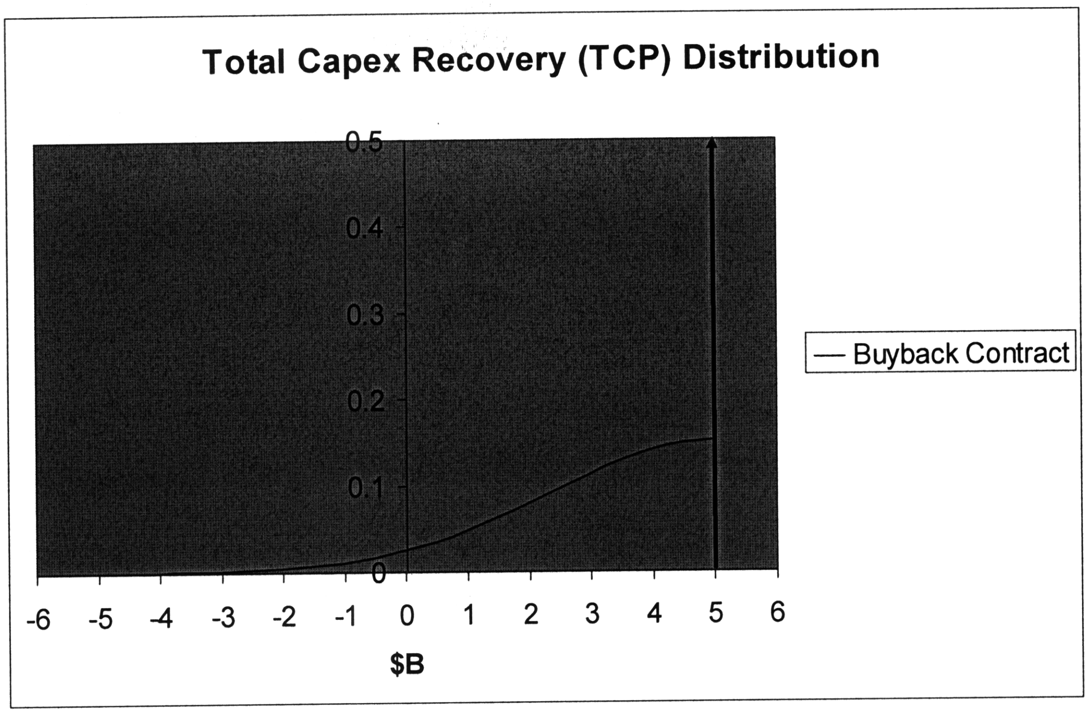


**Figure 13: Total Capex recovery (TCP) Distribution from Year 1 to Year 4**

Next, we consider a scenario that that IOC enters a production sharing contract with 30%-70% split of revenue with the National Oil Company (NOC). The estimated total cost is $ 6.35 billion. The contract limits the IOC cost recovery (cost oil) from 50% to 60% of total production.

The annual cost oil (ACOR) recoveries for year 1 to 4 is approximately 50% of the annual revenue ($R_{LNG}$); thus ACOR follows a normal distribution:

ACOR ~ N ($1.587 billion, $\$^2$ 0.4325 billion).

The annual cost oil recoveries from year 1 to 4 are independent from one another. If we add the independent normal variables, the total four year cost oil recovery (TCOR) distribution will follow a normal distribution as well (Figure 14):

$TCOR \sim N(\$\ 6.35$ billion, $\$^2\ 0.692$ billion)

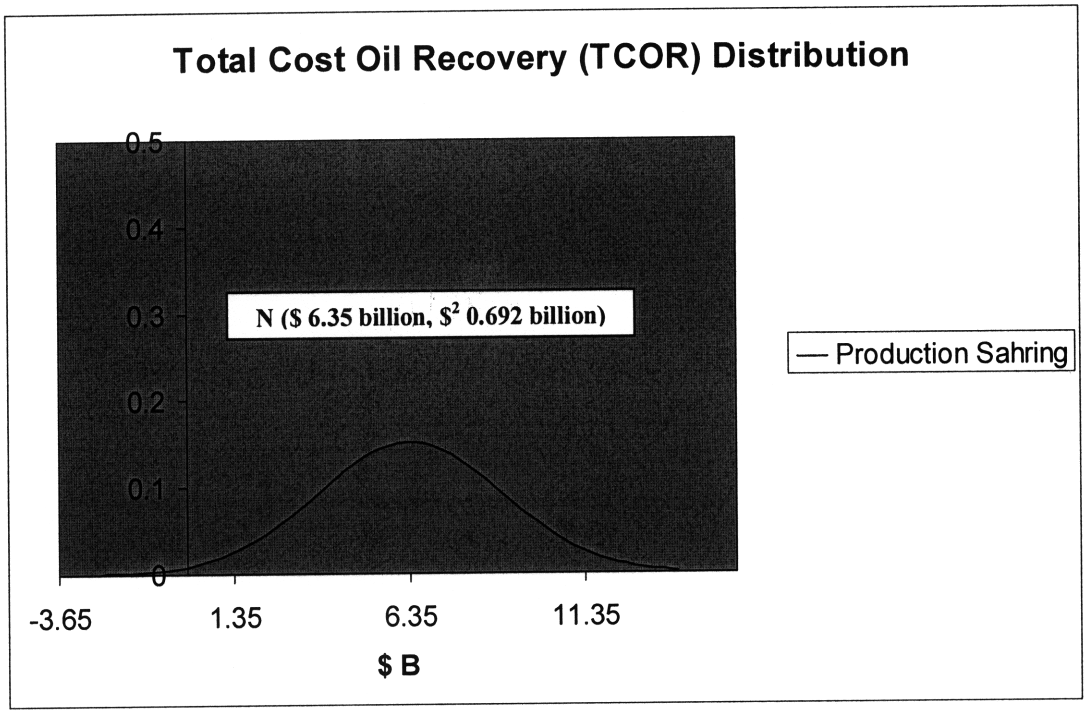


**Figure 14: Total Cost Oil Recovery (TCOR) Distribution from Year 1 to Year 4**

In both buyback and production sharing cases, there is about 16% chance that the project ends up having a Capex overrun of grater than $ 1 billion while still completing in a four year period. Under the buyback contract, the maximum Capex that can be recovered is only $5 billion with probability of 50% but production sharing contract has no ceiling on Capex recovery and there is 12% chance that the entire cost be recovered within four years. When there is residual Capex after year 4, it will be recovered in future years.

There is also about 16% chance that the project ends up with a cost under-run of greater than $1 billion while still completing in a four year period. Under the buyback contract, the probability that Capex recovery exceeds $4 billion is 84%. In product sharing case the probability that Capex is fully recovered in four years is 88%.

In case of a delay, there is 16% chance that project takes more than five years but finishes within budget.

In buyback case, the cost recovery period reduces to less than three years and the chance to recover the entire Capex in three years is only 26% (Figure 15). Of course the IOC misses the cash in flow associated to remuneration fee, bank charges and non-Capex installments of the fourth year as well.

Cash Inflow Missed in Fourth Year: $500 million = 0.25 x ($ 1 billion non Capex+$ 800 million Remuneration + $ 200 million Bank charges)

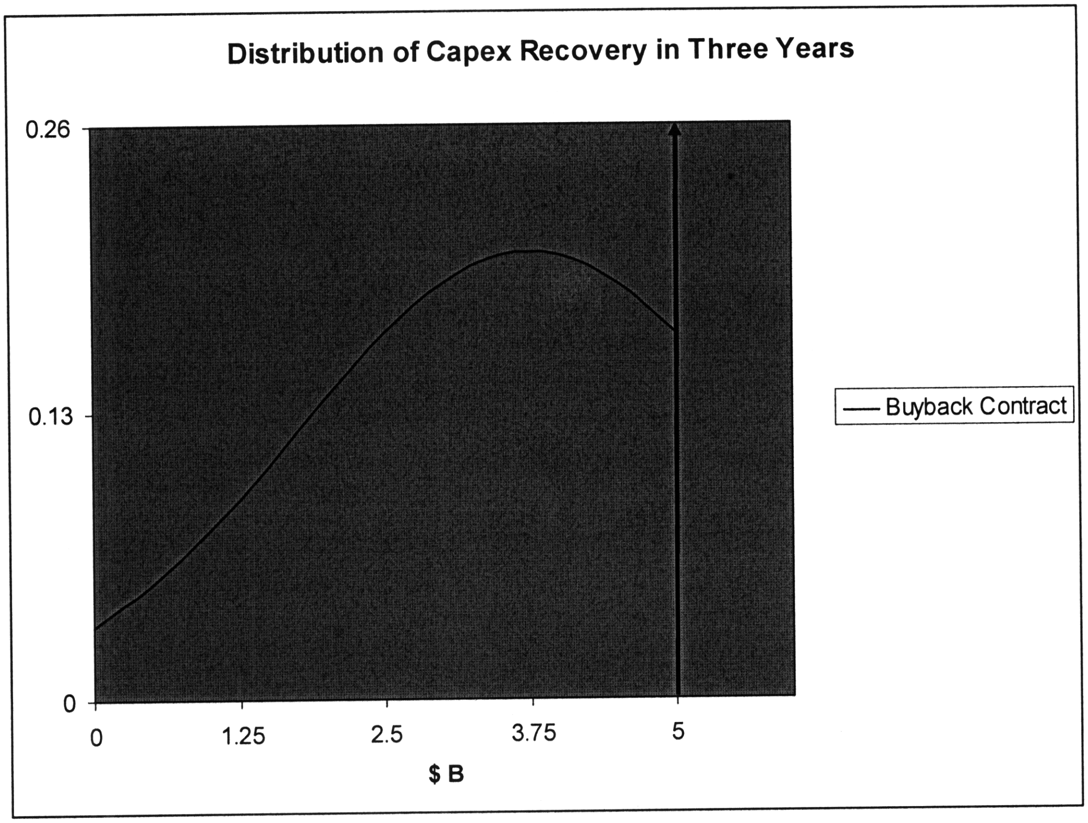


**Figure 15: Distribution of Capex Recovery in Three Years**

Under the production sharing, there is 21% chance that the entire cost oil is recovered in less than three years (Figure 16). But if the cost recovery requires more than three years, there is no cap on the recovery period and the cost oil can be fully recovered. The downside is that the original recovery period is shifted at least one year and the initial projected revenue stream will be missed. For example if it takes four years to recover the cost oil, the missed revenue in the fifth year would be $ 850 million.

Missed Revenue in Fifth Year: $ 855 million = 30% x ($ 3 billion Total Revenue- $150 million Opex)

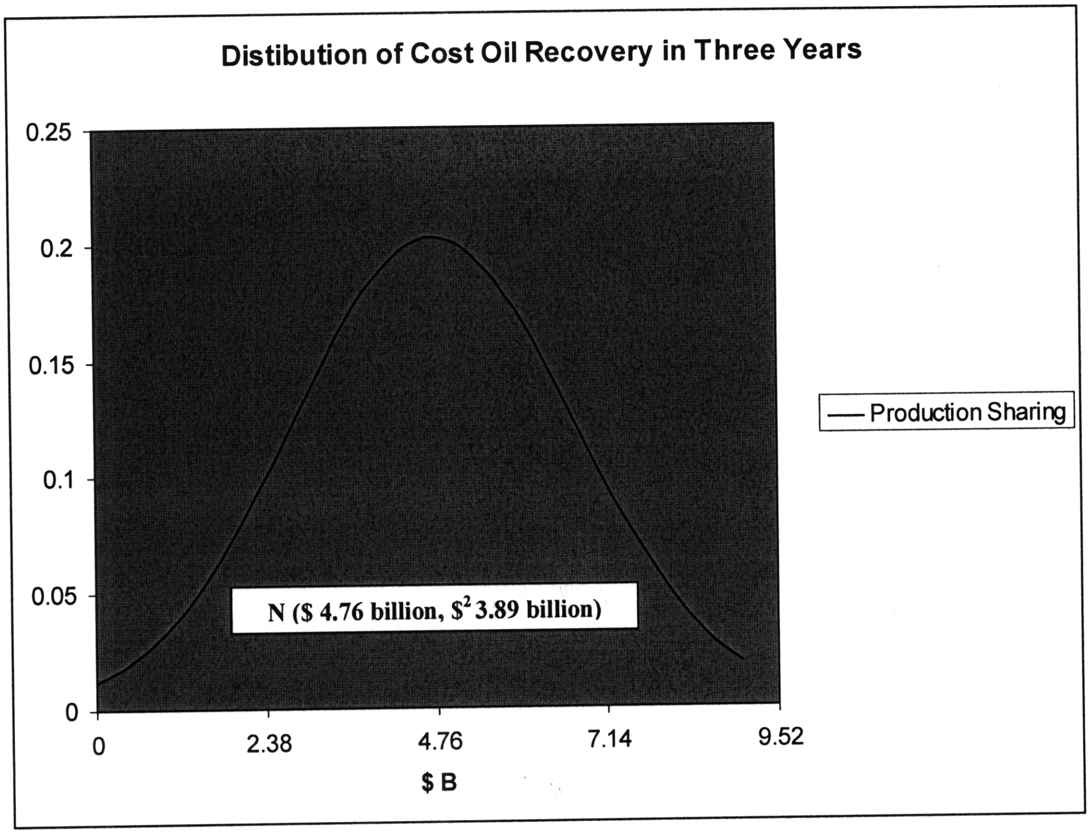


**Figure 16: Distribution of Cost Oil Recovery in Three Years**

## Risks involved in Buyback Contracts

When an IOC company undertakes a buyback contract it faces several risks. First, the IOC has to provide sufficient funding for the project. The Capex, non-Capex and Opex may go beyond the estimated amounts at the time of contracting, but IOC is responsible to fund the project. Second, Capex is only recoverable within the ceiling agreed in the contract. Third, in the course of carrying out the project, more information might become available about the field and MDP might need to be modified accordingly. However, the IOC needs to get the approval of the NIOC for the proposed changes in order to recover its costs. Forth, the recovery of cost and the remuneration fee is subject to meeting MDP goals such as production level. Therefore, if IOC for any reason fails to achieve these goals, the IOC will experience a big loss. Fifth, if the hydrocarbon prices drop and remain low, the time to recover cost may surpass the cost recovery period specified in the contract. Sixth, any delay not related to IOC will postpone the recovery of cost and remuneration fee and the IOC may potentially experience a big loss. For example local sub-contractors may not deliver their work on time or government authorities might delay issuing required licenses.

IOCs can manage the risk related to buyback contracts at two levels. At the project level, IOCs can follow a risk mitigation approach by project shaping. Building robust engineering systems is one way to shape the outcome of projects. At the corporate level, IOCs have to diversify their portfolio of projects in order to reduce the impact of the risk associated with any specific project on their overall cash returns.

NIOC also takes risks by engaging in a buyback contracts. First, the IOC may apply development techniques such as injecting water to the field too early which compromises the long-term productivity of the hydrocarbon reservoir. The reason for such actions is the fixed recovery cost and remuneration fee set at the time of contract and IOC's incentive to finish the project under the predetermined costs. This is certainly a clear example of moral hazards. Additionally, NIOC has stated technology transfer and development of domestic work force as its high level objectives. The conditions in the buyback contracts give no such incentives to the IOC to accommodate such goals. Third, the predetermined scope of work laid out in MDP at the time of contract will force IOCs to bid only for development of reservoirs with safe returns. These reservoirs are typically large, have low development costs and do not need very advanced technology to develop.

From the perspective of NIOC, this exemplifies an adverse selection scenario in which more sophisticated fields requiring more modern technologies are not selected by IOCs for bidding. [18] Another factor that contributes to the adverse selection is the information asymmetry that exists between NIOC and IOC. The information asymmetry is due to the fact that MDP is developed by NIOC prior to awarding the contract.

NIOC's strategy to deal with risks associated with buyback contracts can be different depending on the time horizon. In the short term, to the extent that NIOC can create flexibility in buyback contracts, these contractual risks will be mitigated and NIOC has to embrace the residual risks. In the long run, NIOC has to work with the parliament of Iran and influence the petroleum law in order to overcome the contractual deficiencies of buyback contracts.

**Risks involved in Production Sharing Contracts**

In production sharing contracts like buyback agreements, IOC has to provide sufficient funding for the project. The development cost may go beyond the estimated amounts at the time of contracting but IOC is responsible to fund the project. In case the project fails, IOC bears the financial risk. According to our risk management framework, the best way to mitigate such risk is by diversification of project portfolio at the corporate level.

However unlike buyback contracts, IOC has the incentive to prolong the life of the reservoirs and maximize the net present value of the project. This was certainly the case in the RGX project where the most innovative LNG solution available at the time of contracting was used. Also the incentive to develop domestic work force is higher because IOC is engaged for a long period of time compared to buyback contracts. Finally, there is less information asymmetry between the IOC and the national oil company with respect to the reservoir. For example, in the case of RGX, RasGas the joint venture of ExxonMobil and Qatar Petroleum launched FEED studies prior to the development activity.

**Other Regulatory Risks:**

In addition to the legal regime, the organizational structure of the regulatory body also poses risks to IOCs. In Iran, the hydrocarbon industry is highly fragmented. POGC is responsible for the development of all phases in the South Pars field but National Iranian Gas Export Company (NIGEC) is responsible for downstream and exporting the LNG. For example, if Total wants to develop phase 11 of the South Pars and export the LNG it has to embrace the risk associated with the organizational structure and deal with two different entities. On the other hand Qatar hydrocarbon industry is very monolithic and Qatar Petroleum has been pushing forward with its ambitious LNG ventures in association with the foreign partners. [19]

**Social Acceptability Risks:**

In the past thirty years, Iran and Qatar have faced little or no pressure from the public regarding the oil and gas projects. This is because these projects are built far from the public eyes and they bring high revenues to the communities. Specifically, in the case of Qatar there is no evidence of any public dissatisfaction with the North Dome projects. In the case of Iran, there were some debates in the academic sector whether buyback contracts awarded to foreign companies would comply with the national interest of Iran. But none of these debates turned out as an obstacle for South Pars projects.

**Sovereign Risks:**

Middle East is one of the most volatile regions in the world. In the past thirty years the region has experienced one major revolution in Iran, a war between Iran and Iraq, and two wars between Iraq and US. The region has also been suffering from Arab-Israeli conflicts for more than half a century. Nevertheless, the region remains very important to the International Oil Companies (IOCs) because of its significant hydro carbon reserves.

Regarding our particular case study in South Pars and North Dome, we believe geopolitical risks associated with oil and gas projects in Iran are significantly higher than the ones in Qatar. Both countries experience the systemic geopolitical risks facing the region but in the case of Iran, the country has remained a major force against the western policies in the region and therefore bears higher geopolitical risks.

Historically, the IOCs' approach toward managing sovereign risks has been to influence and transform rules and regulations in these countries and to diversify their project portfolio at the corporate level. Furthermore, at the project level, IOCs either avoid bidding completely in the case of extreme geopolitical risks or demand higher risk adjusted return when they bid for projects in countries with high geopolitical risks.

### *Dynamic Interactions of Technical and Institutional Risks*

We mentioned in chapter 1 that the compound risks resulted from the dynamic interaction of individual risk categories can have dramatic impact on project outcomes and make LEPs potentially ungovernable. In this section, we would like to discuss the dynamic interaction between technical and institutional risks involved in the phases 6, 7 and 8 and RGX.

In phases 6, 7 and 8, Petropars wanted to maximize the use of domestic work force, despite lack of sufficient technical and managerial experience in local contractors. Therefore, Petropars decided to shift some of the technical risks associated with inexperienced local contractors to Statoil through a buyback contract. As we explained in buyback contract section, such contracts carry significant institutional risks because of their limited flexibility for any delays and cost overruns. Consequently, technical challenges of the project combined with the institutional constraints of buyback contracts made phases 6, 7 and 8 a complete disaster for Statoil. NIOC also suffered from the delay in completion because it missed the projected revenues from the project.

On the other hand, RasGas was able to mitigate the technical risk by replicating design and execution as well adopting a single contractor to accelerate the learning curve. Institutional risks were also reduced through the production sharing nature of the join venture. Therefore, we believe the RGX was less risky than phases 6, 7 and 8 from the stand point of compound technical and institutional risks.

We can characterize the differences between dynamic interaction of risks involved in RGX and phases 6, 7 and 8 with a simple simulation. For our simulation we use the exact hypothetical example we previously introduced under *Regulatory Risks* section.

First we assume the project is implemented under buyback contract and use several local contractors. Suppose that due to technical complexity, the project faces a one year delay with $300 million Capex overrun. According to the buyback contract, the IOC can not recover any extra Capex and the recovery period reduces to three years. Consequently, IOC will miss $300 million in Capex recovery. Additionally, the probability that IOC recovers the agreed $5 billion Capex in three years is only 26% and the potential loss due to missing of the projected revenue in the fourth year of initial recovery schedule is $500 million. NIOC will also suffer from the delay in completion because it misses the $ 1.1 billion projected revenue in the fourth year.

NIOC's Missed Revenue in the Fourth Year: $1.1 billion= $ 3billion Total revenue-$ 250 million IOC Non-Capex-$50 million Bank charges -$200 million Remuneration fee-$150 million NIOC Opex -1.25 billion IOC Capex

Next we assume the project is developed under product sharing agreement. We also replicate the design and execution and award the contract to a single contractor. Suppose due to learning effect the project finishes one year ahead of schedule with $300 million cost under-run. In this case, both IOC and NOC benefit from the reduction in project duration and cost. The extra year to recover the cost oil will increase the recovery probability to 72% and any profit at the end of cost recovery is split 70%-30% between NOC and IOC.

Profit of NOC after Cost Oil Recovery Period: $ 1.995= 0.70 x ($3 billion Total revenue -$ 150 million Opex)

Profit of NIOC after Cost Oil Recovery Period: $ 855 million = 30% x ($ 3 billion Total Revenue- $150 million Opex)

This simulation shows how dynamic interaction of risks and the way compound risks are handled can dramatically change the outcome of projects.

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# Chapter 3 Summary and Conclusions

We started this work by underlining the significance of risk analysis and management in oil and gas projects in the Middle East. We also introduced various types of risk and a framework for risk management.

In chapter 2, we first gave an overview of North Dome/ South Pars gas field. We selected two projects from the Iranian territory in South Pars and Qatari territory in North Dome for our case study. The two projects had similar geologies but took place under two different legal regimes. After, we explained the scope of work and the stakeholders involved in each project, we conducted a qualitative risk analysis discussion. In our analysis we compared and contrasted the risk factors and associated risk management strategies between the two projects. We also saw how risks and the strategies to cope with risks influence the outcome of the projects.

Both projects were facing considerable technical risks. In the Qatari scenario, replication of design and execution and assigning EPC contract to a single contract turned out to be a very effective risk management strategy. The project finished ahead of the schedule and within budget. In contrary in case of the Iranian project, the technical risk factors compounded by institutional risks in the absence of effective risk management led to significant delays and cost overruns. We also explained what risk management strategies could be adopted to change the outcome of the Iranian project.

For future, there are several aspects of oil and gas projects that can be investigated. The relationship of risk and complexity deserves further research. Another area that should be studied is the relationship of complexity and project performance.

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# Abbreviations

EPC: Engineering, Procurement and Construction

FEED: Front-End Engineering Design

IEA: International Energy Agency

IOC: International Oil Company

LEP: Large Engineering Project

LIBOR: London Interbank Offered Rate

LNG: Liquefied Natural Gas

LPG: Liquefied Petroleum Gas

Mtoe: Million tones of oil equivalent

Mtpa: Million tones per annum

Mscf: Million standard cubic feet

Mscm: Million Standard Cubic Meters

MDP: master development plan

NIGEC: National Iranian Gas Export Company

NIOC: National Iranian Oil Company

NOC: National Oil Company

POGC: Pars Oil and Gas Company

SBM: Single Buoy Mooring

tcm: Trillion cubic meters

TRIR: Total Recordable Injury Rate

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