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Republic of Yemen
A Natural Gas Incentive Framework

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Abbreviations and Measures

EXCHANGE RATE (EFFECTIVE APRIL 2007)

Currency Unit - Yemeni Riyal
US$1 = YER 195.85

FISCAL YEAR

March 21 – March 20

ABBREVIATIONS AND ACRONYMS

AG	Associated Gas
ARC	Aden Refinery Company
bbl(s)	Barrel(s)
Bcm	Billion Cubic Meter
bcf	Billion Cubic Feet
BLT	Build-Lease-Transfer
BOO	Build-Operate-Own
BOT	Build-Operate-Transfer
BT	Build-Transfer
BTO	Build-Transfer-Operate
Btu	British Thermal Unit
CCGT	Combined Cycle Gas Turbine
CNG	Compressed Natural Gas
CPIA	Country Policy and Institutional Assessment
EIA	Energy Information Administration
E&P	Exploration and Production
FERC	Federal Energy Regulatory Agency
FID	Final Investment Decision
FSA	Feedgas Supply Agreement
FTP	Floor Transfer Price
GDA	Gas Development Agreement
GDP	Gross Domestic Product
G&G	Geophysical and Geological
GIP	Gas-In-Place
GoY	Government of Yemen
GSA	Gas Sales Agreement
GST	General Sales Tax
GTC	Gas Transportation Contract
GW	Gigawatt
GWh	Gigawatt Hour(s)
HFO	Heavy Fuel Oil
HH	Henry Hub
HSFO	Heavy Sulfur Fuel Oil
IEA	International Energy Agency
IMF	International Monetary Fund
IPP	Independent Power Producer

IRR	Internal Rate of Return
JCC	Japan Crude Cocktail
kW	Kilowatt
kWh	Kilowatt Hour(s)
LFO	Light Fuel Oil
LPG	Liquefied Petroleum Gas
LRMC	Long Run Marginal Cost
LRMCC	Long Run Marginal Capacity Cost
LRAIC	Long Run Average Incremental Cost
LRIC	Long Run Incremental Cost
LSFO	Light Sulfur Fuel Oil
LNG	Liquefied Natural Gas
Mbbl	Million barrels
Mcm	Million Cubic Meter
MENA	Middle East and North Africa
MFN	Most Favorite Nation
MOE	Ministry of Electricity
MOM	Ministry of Oil and Minerals
MOU	Memorandum of Understanding
mmcf	Million Cubic Feet
mmtpa	Million Tons per Annum
Mmbtu	Billion British Thermal Units
mmbtu	Million British Thermal Units
MRC	Marib Refinery Company
MW	Megawatt
NAG	Non-Associated Gas
NGP	National Gas Pipeline
NTPA	Negotiated Third Party Access
NPV	Net Present Value
OCGT	Open Cycle Gas Turbine
O&M	Operation and Maintenance
PEPA	Petroleum Exploration and Production Authority
PEC	Public Electricity Cooperation
PSA	Production Sharing Agreement
PSC	Production Sharing Contract
RTPA	Regulated Third Party Access
Tcf	Trillion Cubic Feet
TPES	Total Primary Energy Supply
UK	United Kingdom
US	United States
WACOG	Weighted Average Cost of Gas
YC	Yemen Company
YGC	Yemen Gas Company
YLNG	Yemen Liquefied Natural Gas
YOC	Yemen Oil Company
YOGC	Yemen Oil and Gas Company
YPC	Yemen Petroleum Company
YtF	Yet-to-find Fields

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Conversion Table

1 Cubic Meter (m^3) of natural gas	35.31 Cubic Feet (cf) 0.036 Million British Thermal Units (MMBTU) 10.54 Kilo Watt (s) Per Hour (kWh) 0.0066 Barrels (bbls) of crude oil
1 cf of natural gas	0.00019 Barrels of Oil Equivalent (BOE)
1 Barrel (bbl) of Heavy Fuel Oil (HFO)	5.7 MMBTU of natural gas (based on 40 Mega Joule [Mj]/Kilogram [kg] of HFO) 117 Liters (l) of HFO
1 MMBTU of natural gas	1,000,000 British Thermal Units (BTUs) 293 (kWh) of electricity 0.183 bbl(s) of crude oil
1 Mega Watt (s) (MW)	0.001 Giga Watt (s) (GW) 1.6 Million Cubic Meter ($Mm^{3)}$ 57,600 MMBTU
1 ton of HFO	7.4 bbls of HFO 1,059 l of HFO

Currency Conversion

(Effective April 2007)

Currency Unit – Yemeni Rial

US$1 = YER 195.85

Fiscal Year

March 21-March 20

Units of Measure

bbl(s)	Barrel(s)
Bcf	Billion Cubic Feet
Bcm	Billion Cubic Meter
BOE	Barrel of Oil Equivalent
BTUs	British Thermal Units
cf	Cubic Meter
GW	Giga Watt (s)
GWh	Giga Watt (s) Per Hour
kg	Kilogram
km^2	Square Kilometer
kW	Kilo Watt (s)
kWh	Kilo Watt (s) Per Hour
l	Liters
m^3	Cubic Meter
Mbbl	Million Barrels
Mm^3	Million Cubic Meter
MJ	Mega Joule
MMBTU	Million British Thermal Units
MMCF	Million Cubic Feet
Mt	Million Tons
MTPA	Million Tons Per Annum
MW	Mega Watt (s)
Tcf	Trillion Cubic Feet

Acronyms and Abbreviations

ACCC	Australian Consumer and Competition Commission
AG	Associated Gas
AIPN	American Institute of Petroleum Negotiators
ARC	Aden Refinery Company
AYCC	Arabia-Yemeni Cement Company
BLO	Build, Lease and Own
BLT	Build-Lease-Transfer
BOT	Build-Operate-Transfer
BOO	Build-Operate-Own
BOOT	Build, Own, Operate, Transfer
BT	Build-Transfer
BTO	Build-Transfer-Operate
CCGT	Combined Cycle Gas Turbine
CNG	Compressed Natural Gas
CPI	Commodity Price Index
CPIA	Country Policy and Institutional Assessment
CSF	Contingent Stabilization Fund
EIA	Energy Information Administration
EITI	Extractive Industry Transparency Initiative
E&P	Exploration and Production
ESMAP	Energy Sector Management Assistance Program
EU	European Union
FERC	Federal Energy Regulatory Agency
FID	Final Investment Decision
fob	Free on Board
FPIA	Filipino Participation Incentive Allowance

FSA	Feedgas Supply Agreement
FTP	Floor Transfer Price
GDA	Gas Development Agreement
GDP	Gross Domestic Product
G&G	Geophysical and Geological
GIP	Gas-In-Place
GIIGNL	Groupe International des Importateurs de Gaz Liquefié
GoY	Government of Yemen
GPA	Gas Project Agreement
GSA	Gas Sales Agreement
GST	General Sales Tax
GTC	Gas Transport Contract
HFO	Heavy Fuel Oil
HH	Henry Hub
HSFO	Heavy Sulfur Fuel Oil
IEA	International Energy Agency
IMF	International Monetary Fund
IPP	Independent Power Producer
IRR	Internal Rate of Return
JCC	Japan Crude Cocktail
JV	Joint Venture
Kogas	Korean Gas Corporation
LFO	Light Fuel Oil
LPG	Liquefied Petroleum Gas
LRAIC	Long-Run Average Incremental Cost
LRIC	Long-Run Incremental Cost
LRMC	Long-Run Marginal Cost
LRMCC	Long-Run Marginal Capacity Cost
LNG	Liquefied Natural Gas
LSFO	Light Sulfur Fuel Oil
MENA	Middle East and North Africa
MFN	Most Favoured Nation
MIC	Marginal Incremental Cost
MOE	Ministry of Electricity

MOM	Ministry of Oil and Minerals
MoU	Memorandum of Understanding
MRC	Marib Refinery Company
NAG	NonAssociated Gas
NCC	National Cement Company
NELP-V	New Exploration Licensing Policy Round V
NGP	National Gas Pipeline
NTPA	Negotiated Third Party Access
NPV	Net Present Value
OCGT	Open Cycle Gas Turbine
O&M	Operation and Maintenance
OPEC	Organization of the Petroleum Exporting Countries
OTC	Over The Counter
PEC	Public Electricity Cooperation
PEPA	Petroleum Exploration and Production Authority
PPI	Private Participation in Infrastructure
PPIAF	Public-Private Infrastructure Advisory Facility
PR	Profitability Ratio
PSA	Production Sharing Agreement or Petroleum Sharing Agreement
R/E ratio	Ratio Between Revenue and Expenses
RTPA	Regulated Third Party Access
SI	Saving Index
SOEs	State-Owned Enterprises
T&D	Transmission and Distribution
TPA	Third Party Access
TPES	Total Primary Energy Supply
U.K.	United Kingdom
U.S.	United States
VAT	Value Added Tax
WACOG	Weighted Average Cost of Gas
WTP	Willingness-To-Pay
YC	Yemen Company
YGASSP	Yemen General Authority for Social Security and Pensions
YGC	Yemen Gas Company

YLNG	Yemen Liquefied Natural Gas
YOC	Yemen Oil Company
YOGC	Yemen Oil and Gas Company
YPC	Yemen Petroleum Company
YtF	Yet-to-find Fields

Executive Summary

A Macroeconomic Perspective and the Role of Natural Gas

Fiscal accounts and balance of payments of the Republic of Yemen (referred to as Yemen hereafter) depend upon oil revenues. Currently, nearly 75 percent of central government fiscal revenues and 90 percent of export receipts come from the oil sector. Production levels have been falling as the majority of currently producing fields move toward the end of their economic life cycle. Recent discoveries and technological advances have only partially offset this decline.

For purely macroeconomic planning and fiscal purposes, a prudent approach ignores revenue from "possible" future hydrocarbon reserves until such time as such reserves are proven. This is because the aim of fiscal policy is to ensure fiscal sustainability, which requires that the government's expenditure plans are tailored to match the level of revenue that can be anticipated with a reasonable degree of certainty.

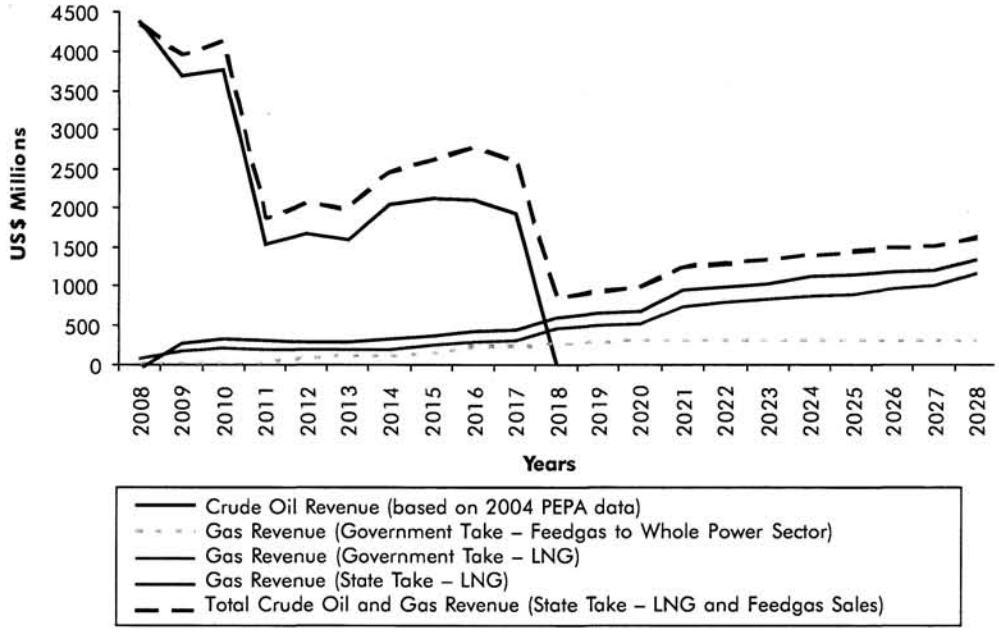
Based on the current level of expenditure and known revenue flows, Yemen is likely to become moderately stressed with regard to the sustainability of its external debt, unless the Government of Yemen (GoY) designs and implements policies aimed at fostering growth and controlling public expenditure levels.

Several areas of the Yemeni economy have been identified as potential sources of government revenue and growth for the nonhydrocarbon economy, including introducing the General Sales Tax (GST), abolishing petroleum subsidies and promoting the agriculture, industrial and services sectors. Even if successful fiscal reforms are implemented, additional sources of government revenue would need to be sought to avoid having to implement sharp fiscal adjustments at a later stage.

Yemen is planning to export gas through Yemen Liquefied Natural Gas (YLNG) starting from 2009. Yemen is also aiming to develop the domestic gas market, in particular gas-to-power. Liquefied Natural Gas (LNG) export revenue and domestic gas sales are expected to partially offset the decline in crude oil revenue from currently producing fields. The fiscal revenue flow that is currently expected to be generated by the hydrocarbon sector over the next 20 years is in Figure 1. (A more detailed explanation of the different lines in the Figure is provided in Chapter 1.)

Realizing these potential fiscal revenues will require developing domestic gas pipeline infrastructure to provide access to the power sector (and potential other customer groups) to this relatively cheap and clean source of energy. GoY has earmarked 5.2 Trillion Cubic Feet (Tcf) of proven gas reserves for the development of the domestic market and there may be more gas yet-to-find. Although the fiscal impact of domestic gas sales is relatively small, the major benefit of developing the domestic gas market is to provide access to the power sector (and potentially the industrial and

Figure 1: Expected State Revenue from Gas and Oil Sales (2008-28)



Source: Authors' calculations.

other sectors) to a relatively cheap and clean source of energy that will create lower energy prices and efficiency gains to the economy as a whole.

Figure 1 shows that current exports of gas through YLNG and domestic gas sales to the power sector will not offset the expected decline in oil production and associated fiscal revenue. The nonhydrocarbon growth potential is limited and the most likely potential for additional sources of revenue in the medium term is the hydrocarbon sector.

However, there are direct efficiency gains from switching the power sector to natural gas arising from lower fuel costs for power generation that lead to lower generation costs per Kilo Watt (s) Per Hour (kWh) and eventually could result in cheaper electricity for final customers. Public Electricity Cooperation (PEC), the power utility, will spend between US$8.6 billion and US$27.8 billion (depending on future oil prices) for purchasing Heavy Fuel Oil (HFO) to meet future power generation demand. If the company switches to natural gas, it will pay between US$4.2 billion and US$10.5 billion to meet future generation demand and this would create substantial savings on generation costs that should have major positive impacts on lower end user tariffs and the effectiveness and competitiveness of the Yemeni economy.

It is imperative that GoY implements measures to further encourage oil and gas Exploration & Production (E&P) activities, and to develop the utilization of natural gas. Incentives to explore and produce oil have been reasonably appropriate for some years now, but few major discoveries are still be made. By contrast, incentives to explore and produce gas have been inadequate and enhancement of the incentive framework could perhaps lead to major discoveries of natural gas. This requires the development of policies and institutions tailored to gas, beyond those appropriate for oil.

It is also worth noting that LNG enjoys significant economies of scale for technological reasons, so, if new associated or nonassociated gas discoveries are made, their production for export could be quite competitive, even if the domestic market could not fully absorb additional production at that time.

The Economic Cost of Domestic Gas

On the basis of currently available data, the economic and financial rate of return of using the gas *domestically* for power generation are higher than the rate of return generated by exporting it. It follows that increasing the level of gas exports from existing gas reserves would be advisable only if enough gas was available to satisfy domestic demand. This is true in theory. In practice, several elements would need to be taken into consideration by policy makers before a decision is made on alternative uses for existing gas reserves.

Yemen has limited proven natural gas resources and the economic value of the existing gas reserves is the opportunity cost of selling it in international markets (through YLNG) or the netback-to-market value of selling the gas to domestic customers – whichever is higher.

The opportunity cost is calculated by netting back the international gas price to the well head at Marib and was estimated at an average of US$2.6/Million British Thermal Units (MMBTU) over a 25-year period. The power sector is the most likely customer of natural gas in the domestic market, and netback calculations demonstrated that an existing oil-fired plant that converts to gas would be willing to pay for natural gas up to US$7.1/MMBTU. This would suggest that the economic rate of return for using the remaining proven gas reserves domestically are higher than the rate of return generated by exporting these gas reserves. This would further suggest that allocating any additional limited gas reserves to export is only advisable once domestic use is fully assured.

The Investors' Perception of Risk in Developing the Domestic Gas Market

In principle, a government would prefer that gas be used domestically when the economic return on investment is higher for domestic use than for export. The private sector would prefer to develop and supply the domestic market when the financial return on investment is higher for domestic use than for export. To date, the only sizable private sector investment in the gas sector in Yemen has been the YLNG export project. In other words, the private sector appears to be unwilling to invest in the development of gas infrastructure for the domestic market. This may be due to the fact that the private sector's perception of political and regulatory risks in Yemen is high. Hence, the "risk-adjusted" financial return on investment may turn out to be much lower than the financial return unadjusted for risk.

The Yemeni government has two options: (a) to finance the development of the domestic gas sector through public funding; or (b) to introduce measures to mitigate the regulatory and political risk to attract private capital. The first option would clearly be undesirable from an economic standpoint since it could lead to the inefficient use of scarce public resources that would otherwise be destined to priority sectors (for example, education, health, sanitation).

The second option should clearly be preferred. Addressing the factors that contribute to decrease the investors' perception of regulatory and political risk would be important to attract foreign investment and management skills, which, in turn, would be indispensable for swiftly developing the domestic gas industry. In addition, this policy option would increase economic efficiency, promote a faster growth and,

at the same time, would not preclude a certain level of GoYs' direct participation. One important way to address the perception of risk is to create an efficient gas market structure and a clear legal and regulatory framework governing it.

The Participation of the Private Sector in Gas Infrastructure Development

The development of a domestic gas market would require the construction of a greenfield gas transmission pipeline, the National Gas Pipeline (NGP). Although the economic and financial viability of this pipeline can be clearly demonstrated, large investments are required for its construction. For this reason, it would be advisable to invite private sector investment or to form a public-private partnership.

Timing is a key factor and the earlier the NGP is built, the higher the net economic benefits to the Yemeni economy. Consequently, a regulatory regime and gas market structure would need to be put in place which are practical, attractive to private investors, consistent with international best practice and suitable to the small size of the Yemeni gas market.

To expedite the development of the gas sector, GoY should allow for private participation in all parts of the gas chain. It is recommended that *no cross-ownership restrictions* apply and market participants be allowed to participate in all parts of the gas chain, including gas production, transmission, distribution, shipping, supply and consumption. In practice, this would mean that the owner and operator of the NGP could well be a gas producer, buyer, seller, transporter and/or customer. To ensure transparency, to enable regulatory oversight and monitoring, to protect end users and to prevent anti-competitive behavior, companies which engage in several areas of the gas chain would be required to *unbundle* and prepare separate accounts for each business activity.

A Suitable Regulatory Regime for the Small Yemeni Gas Market

GoY has substantial leeway in designing a market and regulatory regime for the NGP that is capable of attracting private investors. To this end, it is proposed that separate commodity and transportation contracts, Third Party Access (TPA) rules, firm capacity rights and an attractive tariff regime be adopted.

Given Yemen's limited history and expertise in regulating network businesses, developing a comprehensive legal and regulatory framework (gas law, subregulations and guidelines) would likely be a lengthy process and would risk a further delay in the construction of the NGP. As time is of the essence, it would be advisable to adopt a *"regulation by contract"* approach.

An Institutional Set-up for Regulating the Downstream Gas Sector

In line with the size of its domestic gas market, Yemen has limited institutional capacity. Therefore, although the independent regulator model is a widely accepted best practice model of economic regulation in more advanced economies and larger and mature gas markets, it may not be suitable to apply it in Yemen. A more practical approach may be to entrust an existing government agency(ies) to ensure the supervision and monitoring of the sector, and the control of compliance with the relevant contracts. Credibility of the regulatory regime could be enhanced if some or all of the monitoring functions would be carried out by, for example, international auditors on an annual or biannual basis. However, some consideration should be given to a joint gas and electricity regulatory agency, and it is recommended that the most suitable agency will be identified as part of developing the detailed regulatory regime.

These flexible ownership, market and regulatory arrangements would likely reduce the political

and regulatory risks and increase the incentives for private investors to participate in the market and to develop the NGP.

The Timing of Investment and the Importance of Close Cooperation and Coordination between the Power and Gas Sectors

In the gas industry, the developer of the reservoir and the end user of the gas are linked by a chain that connects the processing plant, the transmission network and the distribution network. Each link corresponds to a commercial relationship, and is dependent on every other link. Because the chain is vulnerable to disruptions, firm and long-term relationships are the norm ("take-or-pay") and/or "ship-or-pay" clauses are generally used).

An anchor project or sector is normally needed to underwrite the development of the domestic gas market. In the case of Yemen, the power sector would be the major anchor customer. Other larger industries, such as the cement sector which is growing rapidly, could also act as anchor customers. Because each link in the chain depends on every other link, it is unlikely that investment will be made in transportation, processing, and further up the chain if the power sector is not ready to receive the gas, or is unwilling to convert to gas. On the other hand, before making such a commitment and converting its appliances to gas, a power sector operator would need to be sure that the NGP will be built and that the gas and transportation tariffs will be attractive. To mitigate the risk, long-term gas supply and gas transportation agreements are normally used.

Geological Potential and Sector Policy

Limited data are available on the potential size of probable and possible reserves in Yemen, and on the likely exploration and development costs. The available data would seem to indicate a relatively low chance of finding *large* oil and gas fields, and a relatively high chance that development cost could be higher than the regional average. This does not necessarily mean that gas reserves would not be found in Yemen, or that it would not be economically viable to develop them. On the other hand, it does suggest that measures may need to be taken by GoY to encourage investment in gas E&P.

The geologic potential is only one of the elements that determine the attractiveness of a country: well head prices, development costs, political risk and the fiscal regime are also taken into consideration by investors in evaluating potential investment opportunities. A host government can affect most of these elements through its policies and actions. In general terms, countries with favorable geologic potential, high well head prices, low development costs and low political risk will tend to offer tougher fiscal terms than countries with less favorable geologic potential, low well head prices, high development costs and high political risk.

No ideal or model regime is available for policy makers to adopt. Each country's circumstances, needs and objectives define the key feature of an appropriate sector policy for hydrocarbon development. Decisions on the design of the appropriate policy can be supported by an understanding of how its various elements and instruments influence decision making and outcomes.

Barriers to Gas Exploration and Development and Possible Options to Address them

In order to design an appropriate policy for gas exploration and development, GoY would need to identify the barriers to investment and to devise appropriate measures to overcome such barriers. Some of these barriers may be short in nature, and/or can be addressed via initiatives

that have a short-term or temporary focus. Others may require regulatory interventions and carry long-term effects. Addressing these barriers would decrease the perception of risk and/or reduce the finding and lifting costs. In other words, addressing these barriers would lower the exploration and development threshold for investment, that is, the minimum size of reserves that would be necessary to justify an investment.

A number of potential barriers to investment were identified in this paper, and possible measures were suggested to overcome them. These were divided into three categories:

- *Measures which are needed to enable gas exploration*. Yemen does not have a hydrocarbon law. Contractual agreements in the form of Production Sharing Agreements (PSAs) are used to regulate exploration, development and production activities. However, existing PSAs and the 2006 Model PSA do not grant the contractor the right to explore for and produce gas, whether associated or nonassociated with oil. Should gas be discovered, GoY and the contractor would need to negotiate a gas development agreement or gas project agreement within a time frame specified in the PSA. While the requirement to enter into negotiations every time gas is found in potentially economic quantities may be justified by the government's need to ensure that fiscal and nonfiscal objectives are adequately taken into consideration, the prospect of potentially long negotiations and the uncertainty of their outcome are likely to discourage investors.

  One possible solution would be to grant gas E&P rights to contractors under the relevant PSA, and to provide for flexible, progressive fiscal terms so as to minimize distortions to investment decisions, and to adapt to the variety of potential project conditions. Key operational principles would need to be laid out, including procedures for obtaining the necessary permits and licenses, evaluation of discoveries and commerciality, preparation, submission and approval of development plans, domestic market obligations and pricing principles. Contractors should be given the right to build and operate high-pressure pipelines, directly or in association with third parties, to transport their gas. The principles for TPA would be laid out in regulations or in the relevant contract. Service contracts and/or amendments to existing PSA could be considered in respect to the development and production of known gas reserves;

- *Measures in which economic impact cannot be practically quantified*. These would include administrative measures aimed at promoting the attractiveness of Yemen's E&P to investors, and improving the efficiency of petroleum operations. In particular, the following were considered: improving the quality and quantity of geotechnical data, facilitating and coordinating multiparty work programs, encouraging multifield gas development projects, streamlining approval procedures, increasing the expenditure thresholds under the PSA, and developing the domestic gas market. The clarity, simplicity and stability of the legal and fiscal regime are also key elements to attracting investors; and

- *Measures which impact can be estimated*. The fiscal regime could be used to convert government's policy into economic signals to the market, and influence investment decisions, provided that the framework is clear, is not changed retroactively and does not discriminate between the actors. Several countries have used favorable taxation of gas to support the development of the gas sector in addition to relevant

sector reforms. Fiscal terms for gas in any given country very much depend on the distance to market and/or on the ability of the domestic market to absorb the volumes that are being produced. For projects that are closed to large markets the fiscal terms for gas are rather similar to those applicable to oil. When gas markets are distant, the government take is normally lower for gas than for oil. This is done either by simply defining a lower government take for gas, or by using self-adjusting profit oil share, taxes and royalties.

Because of the high risk and considerable investment involved in gas exploration and development, the fiscal system would need to take into account the divergent interests of investors and the government. In particular, the fiscal system would need to be able to allocate risks equitably. As risks can be substantially different for different projects and, over time, it would be desirable to build enough flexibility into a system to allow for unforeseen changes, and to minimize the need and cost of negotiations and/or renegotiations. Furthermore, the probability of success, the expected average size of future discoveries and the average finding and lifting costs are key data for the design of an appropriate fiscal system, that is, a fiscal system that is suited to the particular country circumstances. Especially in frontier areas where little is known on prospectivity and cost of development, the use of fiscal systems based on profitability indices would be suggested as they are more likely to capture the variability among projects. Because of their flexibility, these types of arrangement are more likely to encourage the development of marginal fields, and of complex projects with a long lead time for implementation.

Revenue Volatility and Risk Mitigation Strategies

Countries that derive a considerable portion of their revenue from exploiting nonrenewable resources such as hydrocarbons, typically face two problems: the revenue stream is uncertain and volatile; and it does not last forever. Volatile and uncertain fiscal revenue makes it difficult to plan expenditure and to efficiently use public resources. In order to ensure fiscal sustainability when revenue falls sharply and unexpectedly, governments often respond with expenditure cuts. This can be expensive, inefficient and politically unpopular. In addition, it is not easy to distinguish, ex ante, a permanent price shock from a transient one: oil and gas prices have been known to be mean-reverting, but the mean they revert to may not be the same over time. If the price increases substantially, a government may be under pressure to increase its spending, but it may be difficult to do it efficiently.

Oil and natural gas are among the most price volatile commodities. Gas price volatility has traditionally been addressed through the use of long-term contracts. Although for LNG exporters, Yemen's long-term LNG contracts are still the norm, the recent development of a short-term LNG market, and the increased flexibility in price-setting formulae and contract terms of the most recent LNG contracts, may warrant a more sophisticated approach to risk management.

To insulate its fiscal revenue from price volatility, a producing country can adopt different strategies or, better, a portfolio of risk management strategies:

- *Establish a Contingent Stabilization Fund* (CSF). A CSF could be structured to specifically deal with price volatility, that is, the fund would accumulate during periods of high commodity prices. The resources so

accumulated would be used to offset revenue fluctuation in periods of low commodity prices. In order to provide a meaningful insurance against price volatility, the CSF would need to be able to accumulate sufficient liquidity. Countries' experience with CSFs has been mixed. In general terms, a CSF can contribute to insulate government expenditure from price shocks. However, its effectiveness depends on the government's overall fiscal discipline;

- *Borrow abroad to weather temporary shocks or to adjust to permanent price shocks*. In practice, the government may not have easy access to foreign capital markets on reasonable terms, especially in a period of low commodity prices. In addition, repaying the debt when the situation reverses may prove to be difficult;

- *Set fiscal prices for the purpose of calculating royalties, production sharing and corporate taxes*. The fiscal price could be defined as a fixed value over a certain period of time, or it could be indexed to an international Commodity Price Index (CPI) or a portfolio of indices. Although the use of fiscal prices may reduce the volatility in fiscal revenue, it is likely to have a distortive effect on investment decisions; and

- *Transfer the risk of price shocks to those better able to bear it*. There are various ways of doing this: (a) if the State is a party to a gas sales and purchase agreement, floors and ceilings could be established in the pricing mechanism. These provisions are designed to provide a minimum sales price to the seller. In exchange for this protection, the buyer is ensured a maximum purchase price. Alternatively, a less risk adverse seller may prefer to negotiate a lower floor, and maintain the possibility to benefit from a rise in price. Indexation and periodic renegotiation of the price floor and ceiling are usually provided for in this type of agreements; to (b) enter into derivative contracts. Futures and options markets provide the seller (buyer) the ability to either put a floor (ceiling) on prices or buy an insurance against falling (rising) prices. Derivatives may be traded in exchanges or Over the Counter (OTC). Although they mitigate price volatility, these instruments present different degrees of risk and complexities, and entail a certain level of implementation costs.

Expertise is required to understand the risk structure, identify appropriate risk management instruments and to implement and supervise a risk management program. The design and implementation of a risk management program may be subcontracted, but GoY would still need to develop sufficient internal capacity to monitor the program, and communicate its results to the relevant stakeholders.

The financial, legal and institutional implications of setting up a risk management program vary according to the type of instrument used. Commodity hedging programs may require the passing of legislation to authorize the program and establish the boundary conditions for its implementation. Stabilization funds also require specific legislation to regulate the objectives, the rules for accumulation into and withdrawal from the fund and its governance structure.

No risk management program is without risk. The objective of the program, its governance, and the principles to be used to define its success, would need to be clearly specified at the outset, and communicated to the Parliament and the civil society. The political implications of implementing and managing the outcome of these programs should not be underestimated.

Before implementing a particular risk management program, it is good practice to set

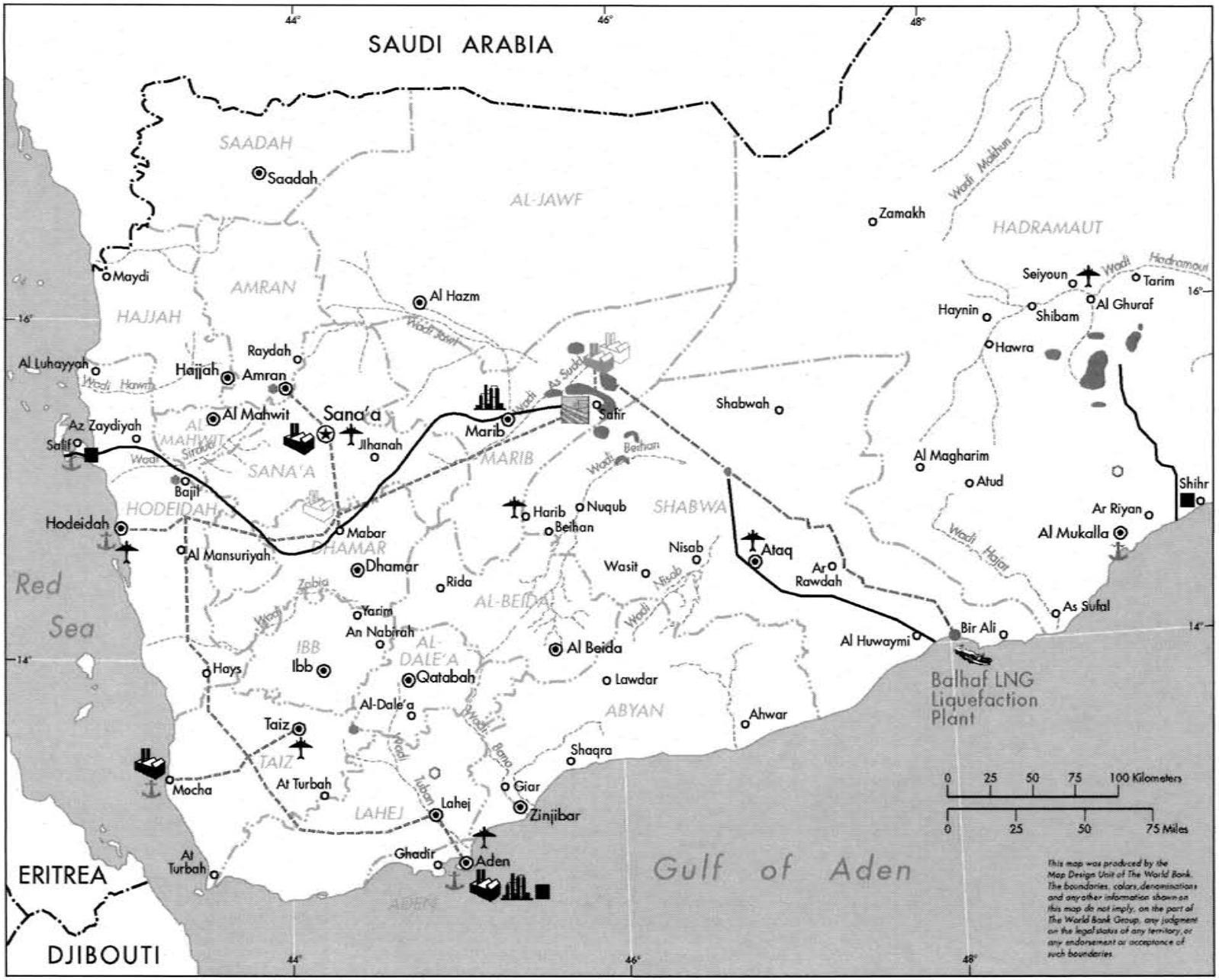
up a virtual program. This would allow GoY to explore different risk management instruments and strategies for a suitably long period of time, with the objective to determine their effectiveness, the relative costs and ease of implementation.

Conclusions

The development of a gas sector has the potential to substantially contribute to Yemen's economic growth and fiscal revenue generation. Because of the high risk and considerable investment involved in developing a gas sector, attracting foreign capital and expertise will be essential. To this end, in addressing the public interest and developing the preferred policies, GoY should ensure that decisions on project development and technologies will be based on their economic merits, and gas will be allowed to find its highest value market. Without this assurance, investors will have less confidence, and gas reserves may remain undeveloped longer than necessary.

IBRD 35560

REPUBLIC OF YEMEN
THE NATURAL GAS MARKET



- PROPOSED NATIONAL GAS PIPELINES
- YEMEN LNG PIPELINE (UNDER CONSTRUCTION)
- MARIB GAS PIPELINE (UNDER CONSTRUCTION)
- LNG TANKER
- PROPOSED GAS GATHERING CENTRE
- SITES FOR NEW POWER GENERATION
- POWER STATION UNDER CONSTRUCTION
- EXISTING THERMAL POWER STATIONS
- OIL REFINERY
- OIL TERMINALS
- OIL PIPELINES
- OIL & GAS FIELDS
- EXISTING CEMENT PLANTS
- UNDER CONSTRUCTION CEMENT PLANTS
- WADIS
- GOVERNORATE BOUNDARIES
- INTERNATIONAL BOUNDARIES
- TOWNS AND VILLAGES
- GOVERNORATE CAPITALS
- NATIONAL CAPITAL
- AIRPORTS
- PORTS

JULY 2007

1. Macroeconomic Outlook for Yemen

Macroeconomic Environment

Yemen's fiscal accounts and balance of payments depend upon oil revenues.[1] Nearly 75 percent of central government fiscal revenues and 90 percent of export receipts depend on the oil sector. In the absence of major new oil discoveries or major technological advance, the long-term outlook looks challenging, as mature fields head toward the end of their economic life cycle.

Yemen's current external debt levels are moderate. Mostly concessional, external debt amounted to US$5 billion at the end of 2005, about 23.3 percent of the Gross Domestic Product (GDP) in Net Present Value (NPV) terms with a debt-service to export ratio of 3 percent. Under the most likely scenario, Yemen's external debt ratios do not breach thresholds of sustainability for a moderate Country Policy and Institutional Assessment (CPIA) performer like Yemen. The relevant thresholds are NPV of debt to GDP ratio of 40 percent and debt-service to export ratio of 20 percent.

However, as noted in 2006 in the Development Policy Review for Yemen by World Bank[2] and the Article IV report of the International Monetary Fund (IMF[3]), negative shocks could easily push Yemen over the external debt sustainability thresholds. Examples of such negative shocks are a 20 percent permanent drop in oil prices or nominal depreciation of 30 percent.

To ensure the long-term sustainability of its external debt, measures should be devised and implemented to foster economic growth, and to limit the expansion of public expenditure. To this end, the long-term objective should be to obtain: (i) a positive nonoil balance; (ii) a manageable level of debt; and (iii) a level and composition of public expenditure that favors growth and poverty reduction. The government's expenditure plan should be tailored to match the level of revenue that can be anticipated with a reasonable degree of certainty.

Based on current knowledge, Yemen's oil reserves are likely to be insufficient to cover the enormous need for pro-poor and development spending.[4] However, Yemen is developing the

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[1] *In March 2007, Yemen joined the Extractive Industries Transparency Initiative (EITI). The EITI is an international organization with a small secretariat located in Oslo, Norway. Involving governments, industry and civil society, EITI aims to increase transparency in financial transactions between companies and their host governments. Transparency permits more accountability which, in turn, is expected to improve the prospects for growth and poverty reduction in countries where extractive industries, such as oil and gas, dominate. Yemen is now in the process of completing the initial sign-up steps to ensure compliance with the EITI process. More background information on EITI can be found on www.eitransparency.org.*

[2] *Development Policy Review, Yemen, The World Bank, 2006.*

[3] *Article IV, International Monetary Fund (IMF), 2006.*

[4] *The latest official information provided on oil production forecasts by Government of Yemen (GoY) is from November 2004. However, Petroleum Exploration and Production Authority (PEPA) indicated to the authors that, on the basis of more updated information, the production levels are expected to increase over the medium term due to improvements to the production facilities in producing fields and new discoveries.*

gas sector and is planning to export gas through Yemen Liquefied Natural Gas (YLNG) starting from 2009. Yemen is also aiming to develop the domestic gas market, in particular gas-to-power. Developing the gas sector is imperative for fiscal sustainability (Figure 1.1).

The expected revenues from Liquefied National Gas (LNG) exports and domestic market gas would only partially offset losses from declining oil production, therefore fiscal adjustment is needed for sustainability.

In 2002, the IMF estimated that in Yemen, a target level of nonoil primary deficit should be around 2.4 percent of the GDP. Revaluing in 2005 prices and allowing for projected gas export revenues, a reasonable level of nonhydrocarbon primary deficit would be approximately 5 percent of the GDP. The actual nonhydrocarbon primary deficit has, to date, exceeded this optimal rate.

To achieve this objective, savings on the expenditure side would need to be implemented. It should be possible to reduce the current level of expenditure by approximately 0.5 percent of GDP per year. This will allow expenditure levels to fall from the current 38 percent of GDP to about 30 percent by 2025. Half of this adjustment is expected to come from the removal of oil subsidies, which are targeted to be completely eliminated by 2007. The other significant expenditure savings are anticipated to come from reforms of the civil service. No savings are expected in capital expenditure, which is projected to remain at around 7.5 percent of the GDP.

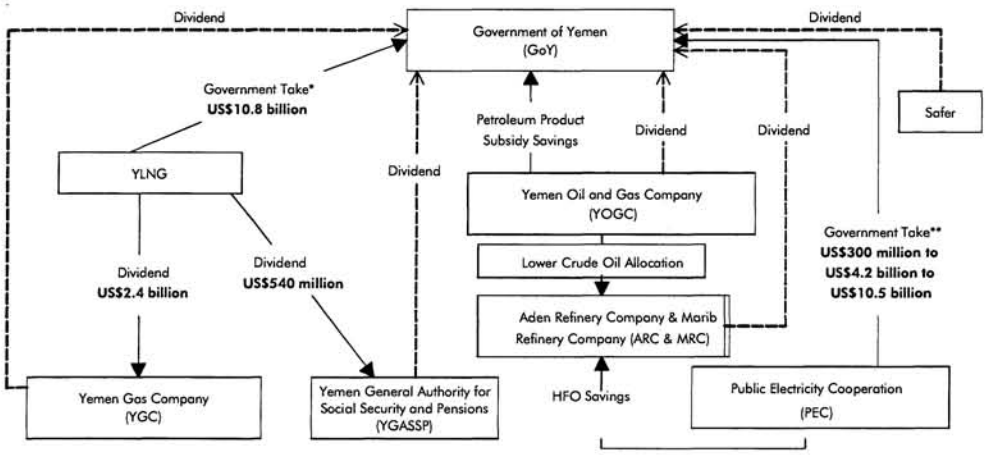
Potential Sources of Economic Growth

Nonoil Sector

Several areas of the Yemeni economy have been identified as potential sources of growth for the nonhydrocarbon economy: agriculture (particularly honey), fishing, building stones, leather products and tourism. However, even substantial increases in exports of these sectors do not have the same potential to contribute to GDP growth and fiscal revenue as the hydrocarbon sector does.

Nonhydrocarbon revenue is expected to increase from about 12 percent of the GDP in 2007 to about 20 percent by 2025.[5] Most of this growth would come from the successful introduction of

Figure 1.1: Projected Government Revenue from Gas Sales (2008-28) – Domestic and Export



*Note: * LNG Government Take includes royalty, bonuses, fixed tax, profit share.*
*** Domestic Government Take includes feed gas sales to PEC.*

[5] *This assumes a relatively narrow definition of fiscal revenue, excluding some of the elements shown in Figure 1.1.*

the General Sales Tax (GST) which is expected to increase the overall level of tax revenue by 1-3 percent of the GDP over the next few years.

To this end, Yemen would need to further intensify its efforts to develop the still-emerging industrial and service sectors. It is expected that a temporary boost to the GDP growth will be felt in the construction phase of the YLNG and the Marib power plant in the period up to 2009.[6] Some spillover effects of these projects will be seen in the construction and services sectors. In addition, the construction and services sectors would benefit from the realization of the National Gas Pipeline (NGP) and the installation of new generation capacity.

Revenue Generated by Switching to Natural Gas in the Power Sector

Once the domestic gas market has been developed, the government can expect a fiscal revenue stream from selling its existing gas reserves from Block 18 at Marib to the power sector.

Annex 1, Table A1.1 sets out the calculations for the government revenue from gas sales to Public Electricity Cooperation (PEC). It is estimated that, from 2008 to 2028, the government would receive approximately US$4.2 billion for sales to PEC of associated gas coming from the Marib field.[7] It is expected that 2.5 Giga Watt (s) (GW) of new or converted gas-fired generation capacity would be installed over the next 20 years. The Government of Yemen (GoY) is currently in negotiations with PEC for gas sales to the 360 Mega Watt (s) (MW) Marib I and the 400 MW Marib II. It is understood that a gas price between US$0.60-0.80/Million British Thermal Units (MMBTU) is being negotiated for these plants.

For all future gas sales, the opportunity costs of exporting the gas through YLNG was assumed to represent the "economic" cost of domestic gas. The opportunity cost of the current proven gas reserves is estimated at US$2.6/MMBTU in real terms (Table 2.2).[8] It was further assumed that all current and future plants use Open Cycle Gas Turbine (OCGT) technology which is currently proposed under the least-cost power expansion plan prepared by PEC.[9]

GoY is currently subsidizing sales of petroleum products in the domestic market, including Heavy Fuel Oil (HFO) which is mainly used by the power sector. By switching to natural gas, the government could reduce the allocation of its profit oil to the refineries and earmark that crude oil for additional exports. The difference between the revenue from selling the freed-up crude oil in international markets and the relatively lower revenue it generates by subsidizing the domestic refineries (and end users) are additional fiscal revenue to the government.[10] Once petroleum subsidies are abolished, there is no additional fiscal revenue to the government from switching the power sector to natural gas, except the revenue generated through the feed gas sales from the Marib Block 18.

Despite fiscal revenue from domestic gas sales being relatively small, there are major benefits

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[6] The total investment in the YLNG project is estimated at US$4 billion and the total investment in the 360 MW Marib power plant and associated electricity infrastructure is estimated at US$500 million.

[7] The natural gas at Marib belongs to the government. The operator of the field is Safer, a State-owned company.

[8] Using the opportunity costs at US$2.6/MMBTU is a conservative approach to calculating economic costs of gas. As pointed out, the economic netback of selling the gas to domestic power sector would be much higher at around US$7/MMBTU.

[9] Should Combined Cycle Gas Turbine (CCGT) technology be introduced, this would reduce the gas volume uptake for power generation by up to 40 percent due to the higher efficiency of these plants. As a consequence, government sale of gas would also decrease accordingly.

[10] Even if Yemen runs out of crude oil (which is anticipated in 2018) and becomes a net importer, those fiscal revenue savings will accrue to the government as long as the petroleum products continue to be subsidized.

to the economy as a whole by switching the power sector (and potentially other sectors and customer groups) to natural gas. Natural gas is a relatively cheap and clean source of energy that will reduce power generation costs and create direct and indirect efficiency gains to the Yemeni economy through lower energy costs.

Direct efficiency gains from switching the power sector to natural gas arise from lower fuel costs for power generation that lead to lower generation costs (per Kilo Watt (s) Per Hour [kWh]) and eventually result in cheaper electricity for final customers. Annex 1, Table A1.1 shows that the power sector will spend US$4.2 billion in the period 2008-28 to supply all generation load with natural gas. This assumes that the gas is priced at the opportunity cost of selling the gas through YLNG, namely at US$2.6/MMBTU. If one would assume that the government charges the economic netback price to the domestic power sector at US$7/MMBTU, the government would earn US$10.5 billion for feed gas sales over the 20-year forecasting period.

Annex 1, Table A1.2 calculates that in case Yemen continues to use HFO instead of natural gas to supply power generators, PEC will have to spend between US$8.6 billion and US$27.8 billion for purchasing HFO, with a base case scenario of US$13.3 billion. These are potentially huge fuel costs savings for power generation and should have major positive impacts on lower end user tariffs and the economy's effectiveness and competitiveness.

There are also *indirect* efficiency gains that are generated by lower energy input costs to the Yemeni economy in general. However, quantifying these indirect efficiency benefits would require a comprehensive modeling of the whole economy (in particular changes in supply and demand for each sector and subsector) which is beyond the scope of this study.

Revenue Generated from LNG Export[11]

In May 2005, the shareholders[12] of YLNG made the Final Investment Decision (FID) to proceed with the construction of an LNG plant in Balhaf and related facilities. Initial capacity of the two-train plant would be of 6.75 Million Tons Per Annum (MTPA), with possibility of further expansion. The total investment is estimated to be approximately US$4 billion,[13] divided into three phases: a preliminary phase prior to FID; a construction phase; and a commercial production phase. The investment will cover the construction of a pipeline from the Marib field to Balhaf, processing, liquefaction, storage and loading facilities and other support facilities. In addition, YLNG agreed to construct and partially finance a spur line from the Marib field toward Maber.

Three sales and purchase agreements have been signed respectively with Suez EDI (2.5 MTPA), Total Gas and Power (2 MTPA) and Korean Gas Corporation (Kogas) (between 1.6 and 2 MTPA). The first two contracts will supply the U.S. market, at a price indexed to the Henry Hub (HH). The third contract will supply the Korean market, at a price indexed to the Japan Crude Cocktail (JCC).[14] In addition, a floor transfer price

[11] *To be noted that in calculating the fiscal revenue from gas exports for the fiscal sustainability scenarios, all revenue streams accruing to State-owned enterprises (SOEs)(that is, Yemen Gas Company (YGC) and Yemen General Authority for Social Security and Pensions [YGASSP]) have been excluded. Since such revenue ultimately flow to government as dividends, this approach significantly underestimates fiscal revenue.*

[12] *Total (39 percent), SK Corporation (9.55 percent), Hyundai Corporation (5.88 percent), Hunt Oil (17.22 percent), Kogas (6 percent), Yemen Gas Company (16.73 percent) and YGASSP (5 percent). During Phase 1 and Phase 2 of the LNG project, YGC's equity will be carried – 14.04 percent by the foreign shareholders and 2.66 percent by the YGASSP.*

[13] *Project financing is expected to be arranged to cover up to 60 percent of the investment. Progress has been slow in finalizing the terms of the financing, and financial closing which was expected to be reached by mid-2006, has not yet been reached.*

[14] *The contract price varies between a floor of US$2.08/MMBTU when the JCC is lower than US$15/Barrel (bbl) and US$3.015/MMBTU when the JCC is higher than US$40/bbl.*

guarantees a minimum price for the calculation of the government profit share and royalties.[15] Deliveries of LNG are expected to start in 2009.

A sliding scale royalty that varies between 2 and 10 percent will apply to all sales of LNG made by YLNG, while a fixed royalty rate applies to Liquefied Petroleum Gas (LPG) sales. Bonuses apply at reaching certain milestones set forth in the Gas Development Agreement (GDA).

Cost recovery limits and investment adjustments also apply. An upstream fee will be paid annually by YLNG to compensate the investment made by the previous investors in the Marib field. Profit will be shared between YLNG and GoY on a sliding scale based on a ratio between Revenue and Expenses (R/E ratio). With the exception of a fixed tax equal to 3 percent of all investment made during Phase 1 and Phase 2 of the project, corporate taxes and other taxes applicable in Yemen will be paid in lieu by GoY.

Government revenue from the LNG project is expected to be approximately US$10.9 billion over the 20 years of validity of GDA, with the possibility of decreasing to US$7.6 billion or reaching US$14.6 billion depending on the level of future gas and oil prices, as well as the level of capital investment and operating costs.

The *State Take*,[16] which includes both the government's share of benefits from the LNG project and the State Owned Enterprises' (SOEs') share of benefits (a substantial portion of which can be expected to flow to government in the form of dividends), could vary between US$9.6 billion and US$18.1 billion, with a base case scenario of US$13.9 billion. Annex 1, Table A1.3 to Table A1.5 show the breakdown by component of government and State revenue under different price scenarios.[17]

Government and State Revenues Flows from Natural Gas

The revenue flows from YLNG are contractually established whereas the forecasted cumulated revenue flows in the domestic market will depend on whether the whole power sector will be switching to natural gas over the next 20 years; and/or all newly established generation capacity will be gas-fired; and/or the government continues to subsidize oil products.

Figure 1.1 outlines the cumulative revenue flows to GoY and to the relevant SOEs for the period 2008-28 based on existing information and data. It sets out the projected revenues from YLNG based on existing contractual arrangements and highlights the range of potential fiscal revenue from the domestic power sector. The size of the fiscal revenue to GoY from the power sector will depend on whether the whole sector will be converted to gas and the timing of the phasing out of petroleum products.

Between 2008 and 2028, GoY will receive US$10.8 billion in royalty, bonuses, fixed tax and profit share from YLNG. The Yemeni government is also entitled to dividend payments from the Yemen Gas Company (YGC) and Yemen

[15] *If the average sales price is lower than the floor transfer price, the difference between GoY's share of profit and the royalties calculated at floor transfer price and GoY's share of profit and the royalties calculated at actual sales price is advanced to GoY by YLNG. The advance is offset against GoY's share of profit and royalties when the actual price is higher than the floor transfer price. This mechanism allows GoY to smooth its share of benefit over time, thus reducing gas price volatility.*

[16] *The "take" measures the sharing of benefits arising from the implementation of an oil and gas project between the host government and oil companies. The "State Take" is defined as the government's percentage of pretax project net cash flow adjusted to take into account any form of government participation. This may include royalties, corporate taxes, production-sharing, and so on, and so forth (Chapter 5 contains a detailed discussion of the take and off tax and nontax instruments commonly used in the oil and gas industry).*

[17] *Estimate of government revenue from the LNG project were made by the authors of this report on the basis of information provided by GoY, and of their own assumptions.*

General Authority for Social Security and Pensions (YGASSP) which, as shareholders of YLNG, receive US$2.4 billion and US$540 million over the next 20 years respectively.[18]

In addition, GoY could derive fiscal revenue from PEC's switching to natural gas. Safer, the State-owned company that owns and operates Block 18 at Marib, supplies PEC with feed gas and is entitled to an operation fee from GoY. The Ministry of Oil and Minerals (MOM), as the owner of all gas reserves, is currently negotiating a Gas Sales Agreement (GSA) with PEC to supply the Marib power plant operated by PEC with feed gas. It is understood that PEC will pay GoY (via MOM) for both the feed gas and the operating costs. Safer will pay a dividend to the government. It was estimated that over a 20-year period, PEC will pay between US$300 million and US$4.2 billion for feed gas to GoY. In the lower case scenario of US$300 million, it is assumed that the only plant running on natural gas is the 360 MW Marib I (the GSA has been currently finalized).

GoY could increase its *Government Take* from feed gas sales to the power sector to US$4.2 billion if all current and new power plants are running on natural gas and the gas is priced at an opportunity cost of US$2.6/MMBTU. In case the government decides to set gas to power prices based on the economic netback to power generation at US$7/MMBTU, it could increase fiscal revenues to US$10.5 billion from 2008-28.

Yemen Oil and Gas Company (YOGC) is responsible for managing GoY share of crude oil production, including exporting the proportion of the government entitlement (that is, profit oil) to international markets and the allocation of crude oil to two domestic refineries, namely Aden Refinery Company (ARC) and Marib Refinery Company (MRC). ARC is the largest refinery in Yemen refining about 80,000 barrels of crude oil per day (bbl[s]/d). In contrast, MRC produces about 10,000 b/d supplying exclusively the domestic market. ARC supplies both the domestic and international markets and is a net importer of HFO.[19] In 2003, ARC exported 464,000 tons, imported 833,000 tons and sold 931,000 tons of HFO to Yemen Petroleum Company (YPC).[20] YPC is the exclusive supplier of HFO (and diesel) to the PEC and other industrial and commercial customers. GoY is currently subsidizing petroleum products for the domestic market, including HFO.

The power sector in Yemen currently runs on HFO. A switch to natural gas would decrease HFO consumption by 47 billion Liters (l) (or 44 Million Tons [Mt]) over 20 years. A reduction in HFO consumption of the power sector would subsequently reduce HFO production and/or imports of ARC and MRC and reduce the crude oil allocation requirement by YOGC. This reduction in domestic crude oil allocation and/or reduced products imports would accrue fiscal revenue to the government as long as energy products are subsidized. Once HFO (and other petroleum products) subsidies are phased out, the fiscal revenue of the government remains the same, irrespective of whether profit oil is sold domestically or in international markets.

The estimated level of *Government Take,* which comprises revenue flows that accrue directly to GoY, and *State Take,* which includes the *Government Take* revenue flows that accrue to SOEs, is summarized in Table 1.1. Potential dividend payments from SOEs (Safer, MRC and

[18] *The payment of dividends would depend on the dividend policy of the companies, as determined by the government as sole shareholders, but the assumption here is that all dividends from LNG to YGC and YGASSP will be transferred to the government.*
[19] *The Oil & Gas Sector in the Republic of Yemen, A Background and Issues Report, The World Bank, November 2004.*
[20] *YPC is responsible for the countrywide distribution and marketing of all petroleum products (except LPG). YOGC acts as the holding company for both YGC and YPC.*

ARC) and subsidy savings to the government by PEC switching to gas are not included in this analysis. Two different scenarios are demonstrated showing different levels of power sector conversion. The *Government* and *State Take* of YLNG is the same in both scenarios as those fiscal revenue flows are contractually established.

Table 1.1 Scenario A, shows that *Government Take* from YLNG and domestic feed gas sales are US$11.2 billion from 2008 to 2028. YGC and YGASSP would receive US$3 billion over the same period. This assumes that only the 360 MW Marib plant is using natural gas over the next 20 years. In total, under Scenario A, the domestic *State Take* is US$0.3 billion and the *State Take* associate with YLNG US$13.9 billion totaling US$14.2 billion over 20 years.

Under Scenario B, it was assumed that the whole power sector will be switching to natural gas (Table A1.1). In that case, the domestic *State Take* is US$4.2 billion and the *State Take* associate with YLNG US$13.9 billion totaling US$18.1 billion over 20 years. The reason why the *State Take* from the domestic sector increased substantially is because of the additional feed gas sales to the power sector over the period at opportunity cost, US$2.6/MMBTU. Under Scenario C, it was assumed that the whole power sector will be switching to natural gas and that the feed gas is sold based on the economic netback value of US$7/MMBTU. In that case, the domestic *State*

Table 1.1: Government and State Take – 2008-28 (in US$ billion)

Scenario A – Conversion of 360 MW Marib Plant	**Government Take**	**YGC & YGASSP**	**State Take**
Domestic	0.3	–	0.3
LNG	10.9	3.0	13.9
Total	**11.2**	**3.0**	**14.2**
Scenario B – Conversion of Whole Power Sector at Opportunity Cost	**Government Take**	**YGC & YGASSP**	**State Take**
Domestic	4.2	–	4.2
LNG	10.9	3.0	13.9
Total	**15.1**	**3.0**	**18.1**
Scenario C – Conversion of Whole Power Sector at Domestic Netback Value	**Government Take**	**YGC & YGASSP**	**State Take**
Domestic	10.5	–	10.5
LNG	10.9	3.0	13.9
Total	**21.4**	**3.0**	**24.4**

Source: Authors' estimates.

Note: Dividend payments of Safer, MRC and ARC and energy subsidy savings of PEC switching to gas are not included in the above revenue flows. It is further important to stress that Yemen may find new associated and nonassociated gas resources that would further increase government revenue from export and domestic sales which are not included.

Take is US$10.5 billion and the *State Take* associate with YLNG US$13.9 billion totaling US$24.4 billion over 20 years.

Conclusions

Based on data provided by GoY in 2004, the country will experience a sharp decline in oil production and associated crude oil exports with the potential of becoming a net crude oil importer in the near future.[21] Figures 1.2, 1.3 and 1.4 set out expected State revenue from gas and oil in the period 2008-28 under different scenarios. It is further understood that recent discoveries in existing and new producing blocks may smooth that trend (but new data have not been made available to the authors).

For purely macroeconomic planning and fiscal purposes, a prudent approach ignores revenue from *"possible"* future hydrocarbon reserves until such time as such reserves are proven. This is because the aim of fiscal policy is to ensure fiscal sustainability[22] which requires that government's expenditure plan are tailored to match the level of revenue that can be anticipated with a reasonable degree of certainty.

In order for Yemen to achieve fiscal sustainability and reach a level of nonhydrocarbon primary deficit[23] of 5-6 percent of the GDP by 2025, strict fiscal policy measures will have to be implemented, including introducing the GST, abolishing petroleum subsidies and promoting the nonhydrocarbon economy (in particular, the industrial and services sectors).

Even if successful fiscal reforms are implemented that allow GoY to double the contribution of nonhydrocarbon revenue to GDP over the next 15 years, additional sources of government income would need to be sought to avoid having to implement sharp fiscal adjustments at a later stage.

Figure 1.2 shows the sharp decline of oil production, the YLNG *Government* and *State Take* and the relatively small fiscal revenue flow from feed gas sale to the 360 MW Marib gas-fired power plant operated by PEC. Figure 1.2 assumes that only the Marib plant will be supplied by natural gas. Overall, gas exports and domestic sales contribute to reduce some of the fiscal revenue decline due to falling crude oil production. However, the overall fiscal position remains challenging and further highlights the importance that the government efficiently uses the revenue generated from oil and gas over the next decade.

Figure 1.3 assumes that the "whole" power sector switches to natural gas, including newly constructed generation plants and pays US$2.6/MMBTU for the feed gas. This could generate substantial fiscal revenue from feed gas sale to PEC and could further offset some of the revenue losses expected from declining crude oil production.

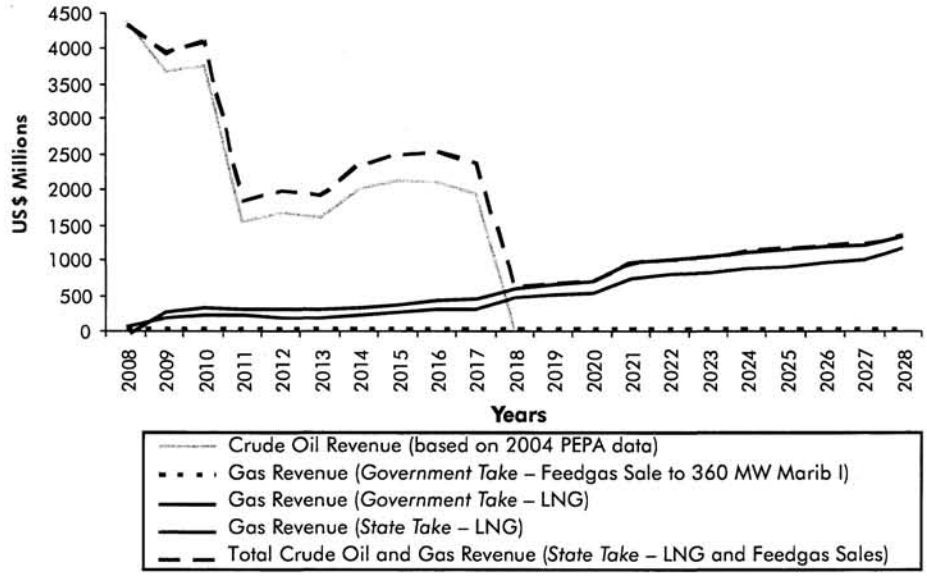
Figure 1.4 assumes that the whole existing and future power generation load runs on natural gas and the sector pays economic netback prices

[21] *To estimate GoY's oil revenue the average take at country level was applied to the production profile provided by PEPA in 2004. No detailed modeling of the terms of existing production sharing agreements contracts was attempted. PEPA has recently provided a new production forecast which takes into account the effect of the use of secondary and tertiary recovery methods on existing fields, as well as new discoveries. The new production profile shows a considerable improvement in production levels over the medium term. Given that secondary and tertiary recovery normally involves high levels of investment, and that commercial terms applicable to new production sharing agreements are likely to differ from historical terms, applying the average take at country level to the new production profile would not be correct. For this reason no attempt was made in this paper to update the revenue forecast. It is however recommended that a more detailed analysis be carried out at contract level.*

[22] *A government's fiscal program is sustainable if its implementation does not result in unacceptable risk of insolvency for the State now or in the future.*

[23] *A primary deficit is the deficit without interest payments.*

Figure 1.2: Expected State Revenue from Gas and Oil (2008-28)

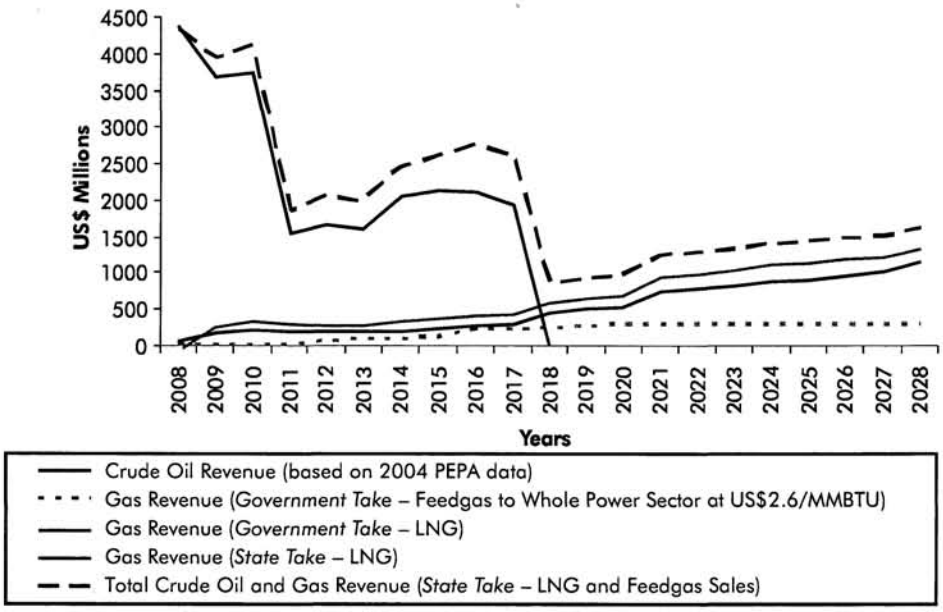


Source: Authors' calculations.

of US$7/MMBTU. This would create substantial fiscal revenues from feed gas sale to GoY and feed gas revenues from selling gas to the domestic power sector match the *Government Take* from YLNG over the 20-year period and substantially raise fiscal revenues.

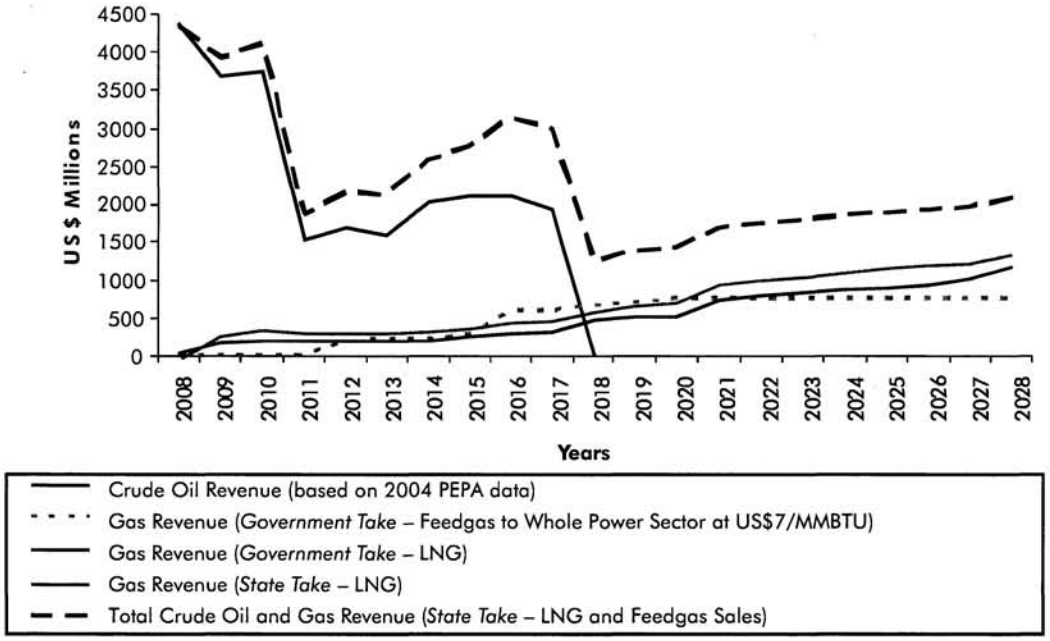
To unleash this potential, GoY will have to promote the development of a domestic gas pipeline infrastructure that is required to provide the power sector (and potential other customer groups) with access to this relatively cheap and clean fuel. This report demonstrates the

Figure 1.3: Expected State Revenue from Gas and Oil (2008-28)



Source: Authors' calculation.

Figure 1.4: Expected State Revenue from Gas and Oil (2008-28)



economics of developing the domestic gas market in Yemen and recommends that the private sector or a private-public partnership leads the effort.

However, the conversion of the domestic power sector to natural gas, and the construction of new gas-fired plant to meet future power demand, will not fully compensate for the fiscal revenue loss expected from falling oil production and crude oil exports. The most likely potential for additional sources of revenue is the oil and gas sector, and it is imperative that GoY take measures to encourage gas and oil Exploration and Production (E&P) activities. Future oil and gas discoveries would allow the government to halt the sharp decline of production and its profit share. New associated or nonassociated gas discoveries provide the government with additional opportunities to generate fiscal revenues through additional LNG exports and/or domestic gas sales.

In addition, substantial nonfiscal benefits could be generated by switching the power sector to natural gas. These efficiency gains would result from lower generation costs that would eventually reduce end user tariffs. It was estimated that efficiency gains could vary between US$4.4 billion and US$23.2 billion over a 20-year period, with a base case scenario of US$9.1 billion if government charges opportunity costs for natural gas. If GoY decides to price along the economic netback of the domestic power sector, direct revenues to the government will increase as discussed above. Simultaneously, direct efficiency gains to the power sector will be lower.

2. Determining the Economic Costs of Natural Gas

Introduction

Yemen is in the process of developing its gas industry and of constructing a LNG facility at Balhaf (YLNG) to export natural gas initially to the Republic of Korea and to the United States, with the possibility of later expansion and diversification of markets. Yemen also aims to develop its domestic gas market, in particular gas-to-power, switching the power generation sector from HFO and diesel to natural gas. GoY also envisages supplying the industrial, commercial and potentially the residential sector with natural gas in the near future.

There is currently a debate within Yemen about the size of the Yemeni proven gas reserves[24] and how to supply both YLNG and the domestic market. It is understood that GoY has allocated 5.2 Trillion Cubic Feet (Tcf) of gas to domestic gas market development.[25] The Petroleum Exploration and Production Authority (PEPA) is currently carrying out an independent audit of its gas reserves.

Under the GDA, dated September 1995, GoY dedicates to YLNG gas reserves from the Marib fields in sufficient amounts to meet the requirements of the project.[26] YLNG has secured an offtake totaling 6.7 MTPA, which is equivalent to the guaranteed capacity of the facility. The facility will have the capability to produce up to 7.2 MTPA of LNG and the incremental 0.5 MTPA of LNG will be employed for spot sales first to existing customer and then to market where appropriately 7.2 MTPA over a 25-year period would require approximately 9 Tcf of natural gas reserves, and the remaining reserves could be used for the domestic market or for extending the YLNG capacity. The *BP Statistical Review* has estimated Yemen proven gas reserves at 16.9 Tcf at the end of 2005.[27] In April 2007, PEPA has estimated 18.2 Tcf of proven Gas-In-Place (GIP).[28]

Gas costing and pricing principles for selling gas in international markets and domestically can be very different. Today, Yemen is able to sell its gas abroad at competitive international gas prices. Under the contractual arrangements, YLNG has agreed to sell gas at prices that are linked to HH for exports to the United States and to JCC for exports to Korea. All gas in Yemen is currently owned by GoY who makes revenues by selling feed gas under the Feedgas Supply Agreement (FSA) from the Marib gas fields to

[24] *Proven gas reserves are generally taken to be those quantities that geological and engineering information indicate with reasonable certainty, and can be recovered in the future from known reservoirs under existing economic and operational conditions.*
[25] *Ministerial Degree (Ref. 2005/66).*
[26] *Gas Development Agreement (GDA), September 21, 1995.*
[27] *BP Statistical Review of World Energy, 2006.*
[28] *A detailed break-up of GIP per field is attached in Annex 2.*

YLNG and by being a stakeholder through YGC under the GDA with Total, the project developer of YLNG. YGC has a 16.73 percent shareholding in YLNG and YGC and GoY are entitled to bonuses, royalties and a share of profit under the GDA. Alternatively, Yemen could sell its remaining proven gas reserves from Marib domestically to power generators, commercial and residential customers. In order to assess whether to export the remaining proven gas reserves or sell it domestically, the economic costs or true costs of these two alternatives have to be further analyzed.

Economic versus Financial Costs of Gas

There are views in Yemen that, because the current gas reserves in the Marib fields are readily available without further E&P investments, and because the only required investment is to develop the infrastructure to transport the gas to final customers, for example, power plants, the costs of domestic gas are small and negligible. In this context, it is important to distinguish between the "economic" and "financial" costs of providing Yemeni gas to final customers.

Financial cost is measured from the flow of actual cash and these flows may include subsidies and taxes (transfer payments). Those costs do not necessarily have anything to do with the true cost of consuming the natural gas. In Yemen, all gas is owned by GoY and, hence, the financial cost for the "commodity" gas to the government is zero. In addition, the gas is readily available at a gas cap at the Marib fields, and it is assumed that operating and capital expenditure for producing that gas is relatively low. A pipeline network will be required to ship the gas from the fields toward the load centers in and around Sana'a and further. However, because YLNG is required to pay part of construction cost of the pipeline network toward Sana'a, it is further assumed that the actual financial costs for GoY to supply the power sector customers are relatively low. The financial cost of the gas will also include any additional taxes the government decides to impose on end users, but the overall financial costs seem to be relatively low.

The *economic cost* is a measurement that reflects the "true" cost of consuming the gas. Those true costs are determined by using efficient prices that would exist in a fully competitive market not distorted by any market imperfections (such as labor market restrictions, limited access to capital, restrictions on the free movements of that gas). The term economic costs implies the cost of something in terms of an opportunity foregone (and the benefits that could be received from that opportunity), or the most valuable foregone alternative.

In Yemen, the benefits of supplying the remaining Marib gas reserves (and any future gas that will be developed) to domestic customers at economic and financial costs would have to be compared with the revenues the country receives by exporting the gas at international market prices or leaving the gas in the ground for consumption in the future.

Knowing the financial and economic cost of gas is essential for Yemeni policy makers for not only calculating any implicit subsidy for domestic gas, but also to compare the net benefit of selling the gas in the domestic market compared to selling it abroad or leaving it in the ground.

Approaches and Methods for Determining Economic Costs

The way economic costs (and associated gas tariffs) are being determined for domestic gas varies depending on the level of gas market development. In fully liberalized and competitive gas markets (such as the United States, Australia, the United Kingdom), multiple gas suppliers compete to sell the commodity gas to domestic or foreign customers ensuring that the gas is priced economically. The construction of

the pipeline network is "regulated" by an independent entity to ensure that Transmission and Distribution (T&D) tariffs reflect the economic costs of supplying customers through the pipeline network, and at the same time to allow the "natural monopoly" network operator to recover prudently incurred investment costs for operating, maintaining and expanding infrastructure and to make a reasonable rate of return on its investment.

In emerging or vertically integrated gas markets (such as Yemen), competition among buyers and sellers does not determine the economic value of the gas at the customer end and governments have to assess both the value of the gas commodity and the associated costs for network development to establish final gas tariffs.

In the case of Yemen, currently all gas is owned by the government and the power sector is State-controlled. At the initial stage of domestic gas market development, there will be no competition between buyers (the State-owned power sector) and the sole seller of gas (that is the government) and GoY will have to determine the economic costs of supplying gas to domestic customers which will require analysis of: a) the cost of gas at the production stage (that is at the well head); and b) the costs at various offtake points from the network (supply).

Gas Production Costs

There are three methods that can be considered to calculate the economic cost of gas at the production stage (that is at the well head), including:

- Marginal cost;
- Netback-of-market value; and
- Opportunity costs.

- **Marginal Cost**

Economic theory states that, in efficient markets, pricing a good or service at its marginal cost maximizes economic welfare. This is because such prices *reflect* the costs involved in providing an additional amount of output. Where a customer values an extra unit more than it would cost to produce it, it is economically efficient to produce that unit. Setting gas prices equal to marginal cost means that customers will continue purchasing additional natural gas, for example, until it is no longer economically efficient to produce the gas at that price. Marginal cost pricing, therefore, provides signals to customers and producers encouraging them to balance the benefits obtained by consuming natural gas with the benefits of producing the resource.

The short-run marginal cost are the marginal costs of an extra unit of output from existing capacity. Long-run marginal costs are the marginal costs for an extra unit including the cost of increasing capacity. The latter concept is more relevant to the costs of long-term infrastructure developments such as natural gas upstream and downstream network.

Despite being theoretically robust, and ensuring that costs are recovered in an expanding system, the calculation of marginal costs is a difficult process and calculation requires modeling of alternative investment plans (or production schedules in the case of gas fields) to meet incremental demand.

- **Netback-of-Market Value**

The principle of this approach is that the economic value of gas is based on the price of substitute goods that customers are willing to pay, with the intermediate costs netted off. This establishes a maximum Willingness-To-Pay (WTP) for gas. The netback-of-market value is therefore the price at which a gas company would price to obtain the maximum possible price from customers without losing market share to another form of energy. The netback-of-market value can be applied both for domestic and international customers.

Box 2.1: Methods for Calculating Marginal Costs at the Well Head

There are two principal methods for calculating marginal costs, including Long-Run Marginal Cost (LRMC) and Long-Run Average Incremental Cost (LRAIC).

The LRMC methodology has been successfully used in utility industries (such as electricity supply, water and telecommunications). Natural gas has much in common with the utilities industries mentioned such as lumpy and indivisible capital investments and a need for excess capacity to meet peak and future demand. LRMC is defined as the cost to meet an increment in demand over all future years. LRMC has several variants, including total LRMC, Marginal Incremental Cost (MIC), Long-Run Marginal Capacity Cost (LRMCC) and Long-Run Incremental Cost (LRIC). LRAIC is a simplified approach which is often used as a "proxy" method to LRMC. LRAIC smooth out lumps in expenditure over time while, at the same time, reflect the general level and trend of future costs which will be incurred as consumption increases.

Netback calculations can be used to generate demand curves that show the quantity of gas that might be bought for a range of prices. This pricing method is a way of calculating the maximum price at which gas could be sold to compete with the substitute fuel for each type of customer. The market value of natural gas is, by definition, the break-even level that makes gas as attractive as the best alternative fuel, taking into account differences in efficiencies, operating costs and investment costs.

Netback pricing is a concept applied in different ways in the gas sector. It is commonly used to estimate well head prices. Netback pricing "nets-back" to the producer from the value of gas at the point of consumption. Knowing the netback price will inform the gas seller of what certain types of customers are willing to pay for natural gas in Yemen and abroad. Although the concept of market value pricing could be applied in Yemen, there are several challenges, including:

- Calculating netback is a data-intensive and time-consuming exercise and the calculation needs to be carried out in a "bottom-up" approach starting from final customers;
- The data for calculating a netback curve is different for each sector and customer, based on the alternative fuels used;
- It may not encourage a rapid development of the domestic gas market, as the price may be too high to encourage switching and demand; and
- The resulting gas prices may be considered too high from a social equity perspective.

However, if successfully applied, this approach would ensure that the gas seller maximizes its revenues from domestic and/or international customers.

- **Opportunity Costs**

Economic pricing theory draws heavily on the concept of opportunity cost. Opportunity cost is the simplest and most direct way of estimating economic cost. Opportunity cost is the value foregone by using a resource in one activity, which necessarily precludes its use in an alternate activity. In Yemen, the opportunity cost of gas in the domestic market is the lost export earnings.

Yemen is in the process of developing LNG export facilities and the LNG market offers competitive access to international gas prices. The opportunity cost of current Yemeni gas is the international price from a relevant destination market (for example, the United States and Korea markets) and netted back to the Marib fields.

The opportunity cost approach is relevant so long as gas is assumed to be *substitutable* between exports and domestic consumption. As long as Yemen has limited gas reserves and the option to export gas, one can assume that gas is substitutable at the margin.[29]

The opportunity cost approach is economically and theoretically valid and its adoption would ensure an efficient use of gas resources for the economy as a whole. It is also a relatively simple calculation not depending on detailed cost data (as required for marginal cost and netback-of-market value calculations). However, there are also a number of challenges associated with this approach. International gas prices are not a unique number and depend on contractual commitments as well as being driven by external factors. For example, YLNG contracts are indexed to JCC and HH prices which may be volatile and unpredictable over longer periods of time. In addition, pricing based on opportunity costs, if translated into domestic prices, is likely to imply higher domestic gas prices compared to an approach based on marginal costs.

Gas Transmission and Distribution Costs

In addition to determining the economic costs of the commodity gas at the well head one has to calculate the infrastructure costs of supplying gas to different offtake points from the transmission network such as major customers (for example, a power plant in Aden or Marber), the costs of supplying different customer categories (for example, cement factory, commercial customers) and also average retail costs for residential load supplied from the distribution system.

This requires an analysis of: (a) the total infrastructure development costs and cost structure, essentially fixed and variable costs of the networks; and (b) an approach for allocating those costs to different offtake points from the gas network and for different categories of customers.

The opportunity cost and market value concepts do not provide the information required for determining costs for physical infrastructure, such as gas pipelines. The appropriate approach is marginal cost.

Economic Costing Options for Yemen

From an economic costing perspective, one has to distinguish between the cost of gas production at the well head and the cost of supplying the gas to customers through the T&D network. To determine the well head price, or production costs, Yemen can, in principle, employ three approaches, namely marginal cost, opportunity cost and netback-of-market value. Table 2.1 summarizes the economic costing options for domestic gas in Yemen.

[29] *The difference to the netback-of-market value approach is that a gas seller would price discriminate among various customer and customer groups abroad based on their WTP to maximize revenues. In contracts, the opportunity cost calculation relies on a single benchmark for a gas price to calculate economic costs, for example, HH for the United States or JCC for Korea, without netting back to the final customer (for example, a power plant or industrial load in each market).*

Box 2.2: Methods for Calculating Marginal Costs for Pipeline Network

There are basically two choices for calculating the economic costs of networks, LRMC and LRAIC.

The calculation of LRMC would require two scenarios for network expansion to be developed. A "base-case scenario" and an "expansion scenario" to meet an increment in demand in the long run. LRMC would be calculated as the NPV of the difference in costs between the two scenarios divided by the NPV of the increment in demand. The main challenge of the LRMC approach is the fact that investment is lumpy and not a smooth continuous function like demand, so a marginal addition to demand may require an incremental lumpy investment.

LRAIC is the most widely applied approach in network costing, for both T&D in gas as well as in other network industries. The LRAIC for a network is the NPV of the cost of a defined expansion plan divided by the NPV of the increases in demand for each year of the plan. Therefore, for existing gas systems, this approach is much simpler as it only requires a single expansion scenario and also corresponds to the way network planners tend to develop their plans.

Table 2.1: Economic Costing Options for Domestic Gas

	Costing Options
Production (at the well head)	• Marginal Cost • Opportunity Cost • Netback-of-Market Value
End User Supply (from network)	• Marginal Cost

In assessing these options, there are two major concepts that have to be considered in determining the economic value of gas, namely:

- The size of Yemeni gas reserves and its gas production capacity; and
- The substitutability (or tradability) between domestic consumption and export.

The size of a country's gas reserves, its production capacity and whether or not they are tradable, are of key importance in determining the appropriate approach for determining the economic value of the gas at the well head.

As long as Yemen faces gas reserve or production constraints to meet future domestic and international demand, incremental Yemeni gas is tradable by exporting it through an expansion of the existing LNG facility. Consequently, the economic value of the Yemeni gas sold in the domestic market can be evaluated using the opportunity cost or netback-of-market value approach. If the netback from domestic users is higher than the opportunity costs from international customers and markets, then Yemen receives the highest economic benefit by selling the gas domestically.

Assuming that Yemen finds large gas reserves to meet both future domestic and international

demand, and there are no gas production constraints, the appropriate method for valuing the gas at the well head to be sold domestically is marginal cost. The marginal cost calculation includes a depletion premium because natural gas is a nonrenewable resource. Using an opportunity or netback-of-market value approach for calculating domestic gas price costs and prices would reduce economic viability because prices would not reflect the true costs of providing the gas.

Gas reserves and production constraints, and the extent to which gas is assumed to be tradable, may change over time in Yemen. The domestic gas market will remain relatively small for the foreseeable future and, if Yemen finds new gas reserves, incremental gas may initially not be fully tradable (for example, until the LNG facility is extended). In the short- to medium-term, there may be gas production or export constraints which could suggest applying the marginal cost approach in a "transition period" before moving to an opportunity cost or netback-to-market value approach until the constraints have been addressed. The marginal cost approach would include a depletion premium to ensure that the trade-off of leaving the gas in the ground today, for production tomorrow, is incorporated in the analysis.[30]

Table 2.2 sets out the various costing principles for domestic gas taking into consideration a country's reserve position and whether it has viable export facilities.

If it is assumed that the combined incremental domestic and international gas demand for Yemeni gas will be greater than Yemeni supply, an opportunity cost or netback-to-market value approach (whichever is higher) based on the substitutability of export for domestic gas demand would be correct. This assumption may change based on a short-, medium- or long-term time horizon. If there are large gas finds in the near future, for example, this would indicate that a marginal cost approach would be more appropriate in the short-to medium-term.

In the Yemeni context, even if there are short-term constraints, because of the substitutability of domestic gas for export gas, the opportunity cost and netback-to-market value approach is relevant and important for GoY to understand the foregone revenues for dedicating gas to the domestic market at marginal cost (rather than exporting the gas at opportunity costs or selling it domestically based on netback-to-market value).

Today, Yemen has limited gas reserves and no existing downstream gas network. To determine

Table 2.2: Economic Costing Principles at the Well Head for Domestic Usage

	Unlimited Gas Reserves and Production Capacity	Limited Gas Reserves and Production Constraint
Tradable	Marginal Cost	Opportunity Cost or Netback-of-Market Value
Nontradable	Marginal Cost	Marginal Cost

[30] *The estimation of a depletion premium for a nonrenewable resource such as natural gas is also an opportunity cost calculation. This is based on the option to extract the resource, sell it and reinvest the proceeds or leave it in the ground for use at a later date. The depletion premium is an additional amount equivalent to the present value of the opportunity cost of extracting the resource at some time in the future, over and above its economic cost today. If the resource constraint is a long way in the future, the depletion premium would be small.*

the *economic costs and value* of domestic gas in Yemen, this would suggest following a long-term costing approach based on:

- Opportunity cost or netback-of-market value from international and domestic customers; and
- Marginal costs for T&D.

Charging solely on a long-run marginal cost basis may ensure that production and transportation costs are recovered to guarantee the sustainable development of the upstream and downstream gas ma rket in Yemen.[31] However, it is important to highlight that if Yemen values its remaining gas reserves based on marginal costs for supplying the domestic market, instead of a costing approach based on opportunity cost or netback-of-market value, it may miss out on *economic rent*.

Indicative Cost Calculations

This section sets outs preliminary calculations using the different costing approaches discussed above. These cost calculations are not intended to be an accurate forecast of the economic and financial costs of Yemeni gas, but an indication based on currently available information and data aiming to highlight the considerations that go into determining the economic and financial costs of selling gas domestically in Yemen.

These calculations are highly sensitive to forecasts of international oil and gas prices, and to assumptions about the dynamics of market penetration by YLNG. Further, the analysis uses the capital and operating costs of a typical oil-fired and gas-fired power plants in the Middle East and North Africa (MENA) and the cost structure and operating characteristics of the existing plants in Yemen may differ.

Opportunity Costs

The opportunity cost of selling gas to the domestic market in Yemen is the foregone export revenue. The components for calculating the opportunity costs in Yemen are set out in Table 2.3:

YLNG has signed long-term gas supply agreements with Kogas (to supply gas to Korea) and Suez and Total (to supply gas to the United States). Gas pricing arrangements from these

Table 2.3: Opportunity Cost for Domestic Gas in Yemen

Long-term LNG contract price for gas
Less regasification cost in target market
Less gas shipping cost from Yemen to target market
Less liquefaction cost at Balhaf
Less cost of pipeline delivery from Marib field to Balhaf LNG plant
Equals netted back gas price at the gas well head at Marib

[31] *Long-run marginal cost pricing in the downstream sector may not ensure full cost recovery in case of low network capacity utilization. Cost recovery can only be assured under a two-part pricing methodology, where the capacity payment is linked to some concept of long-run average capacity cost.*

contracts are a good indicator for calculating opportunity costs (and foregone revenues). The international gas price has to be netted back to the well head to arrive at opportunity costs.

The opportunity cost calculations are based on the World Bank gas price forecasts up to 2030 using Energy Information Administration (EIA) and International Energy Agency (IEA) gas and crude oil price forecasts. Based on those forecasts, the average U.S. natural gas price between 2006 and 2030 is US$5.5/MMBTU (Table 2.4).

As part of reviewing the YLNG project, Charles Rivers Associates (CRA)[32] forecasted HH prices for the next 10 years and estimated gas prices to decrease from US$8/MMBTU in 2008 to around US$4/MMBTU in 2015. Similar calculations were carried out by the consultant for the gas which is sold under the YLNG contract to Korea which is linked to the JCC. CRA calculated that Korean LNG prices will vary between US$6.01/MMBTU in 2007 and US$3.52/MMBTU in 2015. No annualized data was available to the authors from the CRA study.

Shipping rates vary depending on the status of the shipping market but, according to CRA, rates from Yemen (ex-Balhaf) to the United States will be around US$1.2/MMBTU.[33] Regasification cost depends on the size of the facility and its utilization rate. In the United States, regasification costs are estimated at US$0.30/MMBTU.[34]

The largest cost component in the LNG value chain is the liquefaction plant. LNG plant costs are typically high, relative to comparable energy

Table 2.4: Natural Gas Price Forecasts (in US$/MMBTU)

Year	Pricess	Year	Price
2006	6.23	2019	5.00
2007	7.50	2020	5.00
2008	7.00	2021	5.07
2009	6.50	2022	5.13
2010	6.00	2023	5.20
2011	5.50	2024	5.27
2012	5.00	2025	5.33
2013	5.00	2026	5.40
2014	5.00	2027	5.47
2015	5.00	2028	5.54
2016	5.00	2029	5.62
2017	5.00	2030	5.69
2018	5.00	**Average**	**5.50**

Source: The World Bank forecasts based on EIA and IEA data.

[32] *CRA was commissioned by the MOM to review the economic and financial viability of YLNG.*
[33] *Shipping costs to Korea were estimated in the range of US$0.86 to US$0.97/MMBTU.*
[34] *This is according to the Gas Technology Institute (GTI).*

projects for a number of reasons including remote locations and strict design and safety standards. Liquefaction costs vary by size and also whether it is a greenfield or expansion project. It was estimated that generic liquefaction costs amount to around US$1.1/MMBTU for an 8 MMTPS greenfield LNG project.[35]

There is no information available for the project-specific pipeline costs of shipping the gas from the Marib field to the LNG liquefaction plant in Balhaf. For the purpose of this illustration, we assume a cost of US$0.30/MMBTU.[36]

Table 2.5 summarizes the above cost assumptions. The opportunity cost of Yemeni gas at Marib is US$2.6/MMBTU for gas sold into the U.S. market over the next 25 years assuming annual average gas prices of US$5.5/MMBTU.

of the associated gas and a FSA has been signed between the government and YLNG that specifies, inter alia, quantities (to be supplied on a regular, daily, monthly and annual basis) flexibility, specifications, nominations, coordination procedures. The FSA also specifies the price YLNG has to pay to GoY for the gas and it is understood to be US$0.50/MMBTU at the feed gas delivery point.

Assuming that current proven gas reserves will cover all future demand for the domestic market, the marginal production costs of Marib gas would be the minimum cost that an operator would require to recover to operate the facility. Ramboll, a consultant, estimated marginal costs at the well head for existing fields at below US$0.50/MMBTU. However, it is important to stress that these

Table 2.5: Opportunity Cost of Natural Gas in Yemen until 2030

	US$/MMBTU
United States Gas Price Forecast	5.5
Regasification Cost	0.3
Shipping Cost to the United States	1.2
Liquefaction Costs at Balhaf	1.1
Pipeline Cost from Marib to LNG Plant	0.3
Netback Gas Price at Marib	**2.6**

Source: The World Bank estimates based on existing studies, 2006.

Marginal Costs

Yemen's proven gas reserves at Marib are readily available at relatively low production costs, because it is associated gas that was reinjected into a gas cap over many years by the operator. It is assumed that the capital cost for producing Marib gas is relatively low and costs are mostly related to operating the facilities. GoY is the owner

are short-run marginal costs from existing fields. To determine long-run marginal costs, one would have to make an assessment about future capital and operating expenditures for Yet-to-find Fields (YtF) to meet future gas demand. This analysis has not been carried out to date, but it can be assumed that it will be higher than the current short-run marginal cost estimates for the Marib gas.

[35] *EIA, the Global Liquefied Natural Gas Market, Jensen Associates Inc.*
[36] *Ramboll assumed pipeline costs of US$0.29/MMBTU in its 2005 Gas Utilization Study.*

The difference between the opportunity cost approach (calculated based on the netback to the field at US$2.6/MMBTU) and the short-run marginal cost approach (assumed to be below US$0.50/MMBTU for existing fields) is US$2.1/MMBTU. That difference is the "economic rent" or revenue of the government by selling incremental gas from the Marib field domestically at short-run marginal cost.

Netback-to-Market Value

The netback-to-market value is the price a gas company would set to obtain the maximum possible price, or WTP, from customers. The netback concept can be applied to both domestic and international customers.

Carrying out a netback analysis for every single customer (and customer group) in Yemen (and internationally), including the domestic, commercial and industrial sector, would be very data-intensive and time-consuming.

However, the key sector for the development of the future gas market in Yemen, and for the allocation of existing gas reserves, is the power sector and the calculations below provide some indicative numbers on the economic and financial netback of supplying a Combined Cycle Gas Turbine (CCGT) plant with natural gas. International market prices for HFO were assumed for the economic netback calculation. Current subsidized HFO prices were adopted for the financial netback calculation. For both netback calculations, the plant characteristics correspond to typical existing MENA oil- and gas-fired plants.

- **Financial Netback-to-Market Value from Existing Oil-fired Plant**

Table 2.6 sets out the key characteristics of a typical oil-fired and CCGT plant and an indicative calculation of the financial netback when switching from an existing oil-fired plant to a CCGT plant. HFO is highly subsidized in Yemen, and currently the power sector in Yemen pays US¢13 per liter of HFO (or US$15.2/bbl). This translates into current fuel costs of an oil-fired boiler plant of about US¢2.7/kWh[37] (or US$2.7/MMBTU).

Under the existing oil plant assumption, capital costs are treated as "sunk" costs (because it is an existing plant) and, consequently, excluded from the netback calculation. Adding Operation and Maintenance (O&M) costs of US¢0.7/kWh to the per unit HFO fuel price of US¢2.7/kWh lead to total generation costs of US¢3.4/kWh for the existing plant.

Netting those total generation costs back to a typical CCGT plant gives a financial netback of US$2.7/MMBTU. This requires deducting capital costs of US¢0.7/kWh and O&M costs of US¢0.4/kWh from the total generation costs of US¢3.4/kwh. The resulting US¢2.3/kWh per unit fuel costs are converted into British Thermal Units (BTUs) and multiplied by the higher efficiency factor of 52 percent resulting in a netback of US$3.5/MMBTU.[38]

Further deducting average pipeline transportation costs of US$0.80/MMBTU to supply the gas-fired generator in Yemen results in a financial netback at a CCGT plant of US$2.7/MMBTU. In theory, GoY can sell the remaining Marib gas reserves to a new gas-fired power plant at up to US$2.7/MMBTU under the current subsidized regime and still ensuring that the generator will switch from HFO to natural gas.

The financial netback calculation further indicates that returns are higher by switching existing and new oil-fired plant to a CCGT plant instead of exporting the scarce gas reserves.

[37] *1 MMBTU is equivalent to 293 kWh on an energy content basis. Hence, HFO that is priced at US$2.7/MMBTU and is consumed at a thermal efficiency of 34 percent, has a unit fuel cost of US¢2.67/kWh.*

[38] *The US$3.5/MMBTU netback is calculated as follows: US¢2.3/kWh (per unit fuel price) *293 (1 MMBTU equals 293 kWh)* 0.52 (energy efficiency)/100.*

Table 2.6: Financial Netback of Existing Oil-fired Plant

Assumptions	Oil-fired Boiler Plant	CCGT Plant
Generating Capacity (MW)	300	300
Load Factor	75%	75%
Output (GWh/y)	1,971	1,971
Heat Rate (Btu/kWh)**	10,035	6,561
Thermal Efficiency*	34%	52%
Capital Cost (US$/IW)	800	600
Life of the Plant (years)	30	30
Fuel Price (US$/MMBTU)	2.7	**3.5**
Per Unit Fuel Price (US¢/kWh)	2.7	2.3
Other O&M Costs (US¢/kWh)*	0.7	0.4
Per Unit Capital Cost (US¢/kWh)*	1.4	0.7
Generation Costs (US¢/kWh)	3.4	3.4
Pipeline Transportation Costs (US$/MMBTU)		0.8
Financial Netback at Gas Plant (US$/MMBTU)		**2.7**

*Note: *MENA average based on IEA data, **3412 BTU/Efficiency Rate. World Bank estimates.*

However, the financial netback calculations do not take into consideration regulatory and political risk (for example, potential regulated tariffs that do not recover costs and nonpayment) of supplying gas into the domestic market. This is also referred to as a "risk-adjusted" financial return.

In theory, if potential private investors ignore such risk, scarce Yemeni gas resources should be allocated to enable the development of gas infrastructure by private investors. However, experiences from Yemen and other countries suggest that the private sector is very well aware of regulatory and political risks and, in particular, domestic energy pricing policies, and is mostly unwilling to provide large upfront capital investments in infrastructure projects unless those risks are mitigated by the government.

In Yemen, private capital has been adequately available for developing YLNG, but not for gas projects that supply the domestic market. This is an indication that, to date, the risk-adjusted financial return for supplying the domestic market, as perceived by the private investors, is lower than the returns expected from exporting the gas.

- **Economic Netback-to-Market Value from Existing Oil-fired Plant**

For the economic netback calculation, a long-term market price of HFO of US¢26 per Liter (l) (or US$30/bbl) was assumed. This would translate into fuel costs for an existing oil-fired power plant of US$5.3/MMBTU. The economic netback for a typical CCGT plant, switching from an existing oil-fired plant, is calculated in Table 2.7.

As in the case of the financial netback calculation for existing plants, the capital cost component of the oil-fired plant is considered as "sunk" and is not included in the economic netback calculation. Considering the higher thermal efficiency and lower per unit capital and O&M costs of a new CCGT plant, compared to an existing oil-fired plant, the economic netback, or the maximum price GoY can charge for the Marib gas (or the WTP of the CCGT plant

Table 2.7: Economic Netback from Existing Oil-fired Plant

Assumptions	Oil-fired Boiler Plant	CCGT Plant
Generating Capacity (MW)	300	300
Load Factor	75%	75%
Output (GWh/y)	1,971	1,971
Heat Rate (BTU/kWh)**	10,035	6,561
Thermal Efficiency*	34%	52%
Capital Cost (US$/kW)*	800	600
Plant Cost (US$ MM)	240	180
Life of the Plant (years)	30	30
Fuel Price (US$/MMBTU)	**5.3**	**7.4**
Per Unit Fuel Price (US¢/kWh)	5.3	4.9
Other O&M Costs (US¢/kWh)*	0.7	0.4
Per Unit Capital Cost (US¢/kWh)*	1.4	0.7
Generation Costs (US¢/kWh)	6.0	6.0
Pipeline Transportation Costs (US$/MMBTU)		0.3
Economic Netback at Gas Plant (US$/MMBTU)		**7.1**

*Note: *MENA average based on IEA data, **3412 BTU/Efficiency Rate. World Bank estimates.*

operator) is up to US$7.1/MMBTU (considering US$0.30/MMBTU gas transportation costs).[39]

The above calculations suggest that the economic return of selling gas domestically is very high, and potentially higher than selling it in international markets at opportunity costs. However, this assumes that a private investor will carry out the necessary investments required to develop the domestic gas sector and that may require in the Yemeni context that the government substantially reduces investment risk.

Conclusions

There are some views in Yemen that because natural gas is readily available at the Marib field, that gas should be cheaply available for domestic usage, in particular gas-to-power. There is a difference between the economic and financial costs of supplying gas to the domestic market and this paper argues that GoY should consider the true value of its gas resources reflected in the economic costs of consuming the gas.

There are three principal approaches for calculating economic costs, namely opportunity cost, netback-to-market value and marginal cost. Marginal cost is the minimum price a gas seller has to charge to recover its prudently incurred costs. Being a nonrenewable resource, the size of a country's gas reserves as well as its tradability (that is the option to sell it in international gas markets) are of key importance to determine the most efficient costing approach.

Today, Yemen has limited gas resources and the economic value of the existing gas reserves is the opportunity cost of selling it in international markets (through YLNG) or the netback-to-market value of selling the gas to domestic customers (that is, mainly power generation). If Yemen discovers substantial gas reserves that would be sufficient to cover both future domestic and international gas demand, the appropriate domestic pricing approach would solely be based on LRMC.

GoY could, for policy reasons, decide to "dedicate" some of its scarce gas resources, based on marginal costs, to encourage the penetration of natural gas in the domestic market. However, this may create market distortions as the gas could be considered subsidized and demand would be inflated beyond what might be considered efficient resulting in wasteful use of energy. The volume of this excess demand would depend on the gap between marginal cost-based prices and opportunity cost or netback-to-market value-based prices. In addition, by pricing at marginal cost, GoY would miss out on "economic rent" which it could generate by exporting its reserves at international market prices or selling it to domestic customers at netback prices.

The opportunity cost is calculated by netting back the international gas price to the well head in Marib. Preliminary calculations have shown an opportunity cost of US$2.6/MMBTU over 25 years compared to a US$0.50/MMBTU based on a short-run marginal cost approach. There are currently no data available on the LRMC of producing natural gas in Yemen. It is important to point out that this opportunity does not reflect the actual financial payments GoY (and its agencies) receives through the export of the gas. These financial payments would

[39] *The World Bank estimated in 2007 that the netback value of gas in Yemen was at 5.35/MMBTU for an open-cycle gas-fired plant and 7.49/MMBTU for a combined cycle plant respectively. Refer to Razavi, H.,* Natural Gas Pricing in Countries of the Middle East and North Africa, *A World Bank Publication.*

include the revenues from selling the feed gas under the FSA, as well as the bonus and royalty payments, and GoY profit split from YLNG, and the dividends received by YGC for its equity share in YLNG. However, it is unlikely that a project developer would accept financial payments that are higher than the economic netback in the long run.

The power sector is the most likely customer for Yemeni gas and a preliminary netback-to-market calculation has shown that the economic netback for an existing oil-fired plant that switches to a gas-fired power plant would be US$7.1/MMBTU respectively. The current financial netback for a similar existing oil-fired plant switching would be US$2.7/MMBTU.

These indicative calculations suggest that the economic and financial rate of return to using the gas domestically for power generation are higher than the rate of return generated by exporting the remaining gas reserves. In theory, if economic netback values from the domestic power sector are consistently higher than future gas export revenues, then allocating any additional limited gas reserves to export is only advisable once domestic use is fully assured over the long run. In practice, policy makers have to be aware of several issues before translating the above indicative findings into actual decisions of allocating remaining gas reserves to develop the domestic sector.

In principle, if the economic return is much higher for domestic use than for gas exports, investment in domestic use is the preferred option for GoY. Further, if the financial return is higher for domestic use than for gas exports, this would suggest that the private sector would prefer to develop and supply the domestic market. However, what we have experienced in Yemen is that the private sector has been unwilling, to date, to provide capital to invest in gas E&P and to develop gas infrastructure. That has encouraged GoY to explore gas export options, in which the private sector has demonstrated its willingness to invest.

This may suggest that although the financial netback calculations in this paper suggest a higher financial return for domestic usage than for exporting the gas, the "risk-adjusted" financial return by the private investors may actually be much lower. This is mostly caused by regulatory and political risk assumptions of the private sector and, most importantly, by the perception that domestic gas prices will not even allow for cost recovery of supplying the gas domestically.

The likely unwillingness of private investors to develop gas reserves and infrastructure for the domestic market also has implications for using the economic netback, which is comparatively high for domestic gas usage as a policy benchmark for utilizing the remaining Yemeni gas reserves.

Unless domestic gas prices, regulatory and political risks are reduced, it is likely that no private investor will be willing to contribute to the development of the domestic gas market. This could lead to the allocation of scarce public resources to develop domestic gas infrastructure and crowd out public investment in education, health, infrastructure and other sectors that may potentially create higher economic returns for Yemen.

This public financing effect could be mitigated by the government recovering fiscal resources from the gas sector by taxation of the considerable amount of "economic rent" from the development of natural gas resources in Yemen. These tax revenues could be utilized for public expenditure in other sectors.

A more important aspect may be that financing requirements for developing the domestic gas market are substantial and public borrowing could seriously reduce the government's ability to borrow for other important investment

projects that can only be financed publicly. It was estimated that the construction of the NGP would require an investment of approximately US$800 million. At the same time, current public debt of Yemen is about US$5 billion. As a consequence, public borrowing of a large share of the capital required to develop gas transportation infrastructure may affect the country's overall borrowing capacity and jeopardize its servicing of debt capability.

Consequently, unless it can be assured that the private sector develops the domestic gas sector, it may be undesirable for decision makers to follow economic returns as their principal criterion for allocating the remaining gas reserves, and for developing the domestic market. In contrast, if the private sector is willing to finance domestic gas infrastructure, the above calculations indicate that the economic returns are much higher by selling the gas to the domestic power sector than for export.

3. A Framework for Developing the Domestic Gas Market

Introduction

The previous Chapter has highlighted the comparative economic benefits of supplying the domestic market with natural gas for power generation in Yemen. Various gas utilization studies have been carried out over the last decade evaluating the economic and financial viability of developing the domestic market.[40] Although there remain uncertainties about the exact technical specification and sizing of pipelines, there seems to be a broad consensus on the viability of building domestic gas infrastructure and on the routing and corridor for a future NGP.

Justifying the development of a domestic gas infrastructure network based on ambitious sector growth forecasts of the commercial, industrial and agricultural sector in Yemen, and based on new sunrise industries in the country (for example, petrochemical sector, fertilizer industries), have to be viewed with some skepticism. International experience shows that greenfield gas development and setting up of new gas markets require *anchor customers* who consume large volumes of gas, preferably with high load factors, and are willing to enter into long-term commercial agreements for the purchase of the commodity gas and for the conveyance of the gas in the transportation system. That anchor customer in Yemen is the power sector.

Consequently, it is the economics of converting and connecting the power sector to natural gas, and its willingness to enter into long-term contractual arrangements with the pipeline company, which will be a key determinant of the timing and sizing of new gas transmission infrastructure. Switching the power sector to natural gas in Yemen would reduce its oil dependency which could be earmarked for exports to boost government revenues. It was estimated that over a 30-year period, about 800 million bbl(s) of crude oil could be saved by the power sector by switching to natural gas. Analyzing further, the power sector as a potential anchor customer for gas and addressing potential barriers is one of the objectives of this Chapter.

It was further argued that Yemen has limited public funding, and that scarce public resources should be allocated to areas where private capital is not available, and where public financing may create potentially higher economic returns. Consequently, creating an investor-friendly environment that reduces regulatory and political risk for domestic gas

[40] *Ramboll, Natural Gas Utilization Study, Yemen, November 2005; Gas Strategies, Natural Gas Pipeline Prefeasibility Study, August 2002; Beicip-Franlab, Master Plan for the Development of the Electricity Supply and the Utilization of Natural Gas, October 1999; Gasunie Engineering B.V. Gas Utilization Study, June 1992.*

pipeline development will be of key importance to develop the domestic gas market. Broadly setting out such a framework is another objective of this Chapter.

The Power Sector as Anchor Customer

Future Gas Demand and the Importance of Anchor Load

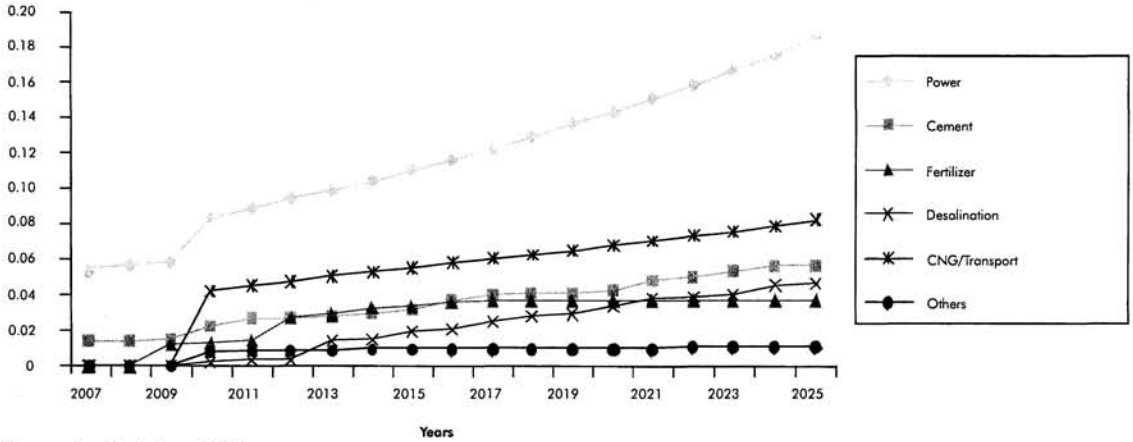
Ramboll, a consultant, had carried out a gas demand forecast in 2005 which is summarized in Figure 3.1.[41] For existing industries, it shows the key importance of the power sector which is discussed in more detail below. Switching of existing and construction of new cement plants offers additional opportunities for natural gas.

In 2006, Yemen State-owned cement plants produced 1.5 Mt of cement and importing an additional 2.2 Mt to meet domestic demand. It is understood that two existing State-owned plants are currently being expanded and new privately financed projects are under planning and implementation which could increase domestic production to around 6 MTPA from 2011. This would require 500 Million Cubic Meters (Mcm) of natural gas annually to meet that cement sector demand if switched to natural gas.

Currently, National Cement Company (NCC) and Arabia-Yemeni Cement Company (AYCC), two private project developers, plan to import coal from South Africa and Indonesia at an estimated cost of US$2.5-3.7/MMBTU to provide both plants with energy. This price is the plant delivery price and includes all duties and taxes, freight and handling. In addition, these plants are installing imbedded power generation of 32 MW and 36 MW using fuel oil.[42] This power demand could add another 100 Mcm of gas annually if those plants can be connected to natural gas supply at a later stage.

All other industries on the graph, including fertilizer, desalination and CNG/transportation are not established to date in Yemen.

Figure 3.1: Estimate of Gas Consumption (in Tcf) 2007-25



Source: Ramboll, June 2006.

[41] *Ramboll has estimated the total annual gas market in Yemen in 2025 at 0.42 Tcf (corresponding to 12 Billion Cubic Meter [Bcm]) using a bottom-up or sector approach. The consultant's top-down approach, based on Total Primary Energy Supply (TPES) per capita, and the natural gas share per TPES from other relevant jurisdictions estimated demand between 12.2 and 17.6 Bcm.*

[42] *The NCC plant will be built near Aden and the AYCC plant near Al Mukalla where supply from the currently planned NGP is not envisaged but could, in theory, be supplied from another gas source in Hadramout. The new Aden cement plant could potentially be supplied from the NGP if it is built until Aden.*

While new industries may develop in the near future, the construction of a greenfield gas transmission pipeline requires that anchor customers are willing to enter into long-term contractual arrangements for the supply and transportation of gas to mitigate the risk of potential pipeline investors. Typical long-term contractual arrangements for greenfield gas transmission pipeline developments include:

- Gas Sales Agreement(s) – GSA(s); and
- Gas Transport Contract(s) – GTC(s).

GSA(s) are contracts between parties for the purchase and sale of the commodity natural gas and tend to include take-or-pay clauses.[43] GTC(s) are contracts for the conveyance of gas on a pipeline network and tend to include firm capacity rights.[44]

International experience shows that without those contractual arrangements, including take-or-pay clauses and firm capacity rights, it is unlikely that a private investor would finance greenfield gas pipeline development in Yemen.

There are industries that GoY aims to promote, such as fertilizer, desalination plants, natural gas vehicles and others that could use natural gas in the future. However, those are not industries that are established to date. Hence, it is the power sector that will have to act as the anchor customer for the gas market and pipeline development and sign long-term GSA(s) and GTC(s). Without that commitment, it is unlikely that a private investor would be willing to finance the construction of pipelines in Yemen.[45]

The Characteristics of the Power Sector

An "anchor customer" is a large customer(s) that is needed to make a pipeline project financially attractive to investors. The Yemeni power sector is of key importance for the development of the domestic gas market and the economics of greenfield gas pipeline construction. There is some potential to convert existing industrial load to natural gas, that is, cement, but the gas volume uptake of those sectors are relatively small.

Yemen is short of power and the least electrified country in the MENA region, with only about 40 percent of the population having access to electricity. The PEC, the State-owned power utility and sole supplier of electricity, has around 774 MW of installed generation capacity on its interconnected system.[46] All of PEC's plants are currently running on HFO/ Light Fuel Oil (LFO) and/or diesel and the company estimated that with demand for electricity growing steadily and assuming a reserve margin of 21 percent for maintenance and unplanned outages of generation units, it would require an additional 1,400 MW of installed generation capacity to meet its target of 2,200 MW by 2010. In total, about 3,000 MW is planned to be constructed over the next 20 years.[47] This is an ambitious plan but highlights the potential for future gas-fired plants in Yemen.

To ensure efficient investment in new generation capacity, GoY should consider developing and establishing policies that attract private

[43] *A contract provision obligating the buyer to pay for a certain minimum quantity of a product irrespective of whether or not the buyer actually takes that quantity during the stated period.*

[44] *A firm capacity provides the shipper with a right to use reserved, prespecified and defined capacity on a pipeline to ship gas. However, the shipper will have to pay for the firm capacity irrespective of whether or not gas is actually shipped on the pipeline on his behalf.*

[45] *Generators who are required to sign take-or-pay contracts for gas supply tend to mitigate that risk by requiring take-or-pay minimum offtake of power under their long-term power sales agreements with final customers. This will mitigate and avoid the risk of mismatch between fuel purchase and fuel consumption.*

[46] *PEC operates an estimated 80 percent of the country's generating capacity. The remainder of Yemen's electricity is generated by small off-grid suppliers and privately-owned generators in rural areas.*

[47] *Kennedy & Dunking prepared a Power Generation Master Plan covering the period 2000-2025. The plan was updated in 2003 in cooperation with the World Bank and PEC.*

investment in power generation by Independent Power Producers (IPPs).[48]

Current power tariffs do not reflect the costs of supply and PEC lacks liquidity. Despite the demonstrated economic and financial benefits to the power sector, moving away from HFO and taking up natural gas requires financial strengthening of the sector and reform and restructuring.

PEC's least-cost generation expansion approach not only aims to commission new gas-fired power plants, but also to convert some of the existing plants which currently run on HFO and diesel to natural gas.

Table 3.1 shows that 600 MW of existing plant capacity could be converted to natural gas in the interconnected system. In principle, 94 MW of generation capacity at Al-Rayan and Wadi Hadramout could also be converted to natural gas. However, that capacity supplies isolated systems in the western desert part of the country which is not located near any proposed gas pipeline infrastructure. Consequently, it is not included in the subsequent analysis.

Table 3.2 sets out new gas-fired power plants that are currently being commissioned or are at the planning stage. PEC is currently constructing a new 360 MW open-cycle gas-fired plant (OCGT) in Marib and is preparing the extension of the plant with an additional 400 MW. The Marib plant will be supplied by a short dedicated gas pipeline from the Marib gas field.

PEC's least-cost generation expansion plan further envisages the construction of an OCGT plant in two phases in Maber, south of Sana'a. Phase I would install 400 MW of capacity and Phase II an additional 800 MW. Both phases are still at a planning stage.

Table 3.1: Existing Generation Plants Suitable for Conversion to Natural Gas

Power Station	Fuel-type	Total Installed Capacity in 2005 (MW)	Total Energy Generated in 2005 (GWh)
Interconnected System			
Ras Katnib	HFO	150	1,014
Al-Mokha	HFO	160	767
Al-Hiswa	HFO	125	719
Al-Mansoura	Diesel	64	277
Hizyaz-1 Hizyaz-2	Diesel LFO+HFO	30 68	690
Total		**597**	**3,467**
Isolated System			
Al-Rayan	HFO	47	227
Wadi Hadramout	Diesel	47	211
Total		**94**	**438**

Source: Information provided by Public Electricity Cooperation (PEC).

[48] *Even under the existing market structure for the power sector, with PEC as a vertically integrated electricity utility, IPPs could be promoted and established selling power under long-term supply agreements to PEC. This could help to meet the ambitious new power generation capacity requirements and may improve overall efficiency of the sector.*

Table 3.2: Commissioned and Planned Gas-fired Power Plants

Power Station	Fuel-type	Total Installed Capacity (MW)
Commissioned		
Marib I	OCGT	360
Planned		
Marib II	OCGT	400
Maber I	OCGT	400
Maber II	OCGT	800
Total		**1,960**

Source: Information provided by PEC.

PEC is planning open cycle instead of combined cycle plant technology for both Marib and Marber. An open cycle gas-fired plant burns gas to operate a turbine; a combined cycle turbine also uses waste heat to produce steam and generate further electricity.[49] With 34 percent efficiency, OCGT plants have a lower efficiency than CCGT plants.[50] Modern CCGT plants can get up to 58 percent efficiency, but are generally around 55 percent.

According to PEC, for cooling the steam turbine and for producing steam in a CCGT plant, large quantities of cooling water are required that are not readily available in the Marib and Marber desert areas where the plants are being located. Consequently, OCGT technology was selected.

One of the major advantages of the construction of a NGP, which will partly run along the Red Sea coast, is the access to cooling water and potential to construct modern CCGT plants (possibly in combination with a desalination plant). PEC is in the process of reviewing its least-cost power generation expansion plan by carrying out a technical and economic analysis of moving the planned new 1,200 MW generation capacity from Maber to the coast, using CCGT technology.

In total, there is about 2,500 MW of existing and planned power generation capacity that could potentially run on natural gas. The economics of converting or building a new gas-fired plant can be analyzed by calculating an "economic" netback. The economic netback is the maximum price an existing power plant operator would be willing to pay for the gas without losing market or without being "worse-off" than running the plant on current fuel.

The economic netback calculation is a comparative analysis of running a new or existing HFO plant and an OCGT or CCGT plant and includes an assessment of:

[49] *A two-stage electrical generation process is carried out in a CCGT. In the first stage, electricity is generated by a gas turbine. The waste heat is then used to generate more power by steam turbine.*

[50] *The thermal efficiency rate of 34 percent for OCGT plant reflects the rate of older simple cycle generators. Modern aero-derivative simple cycle generators can have an efficiency rate of around 43 percent. The most suitable technology for Yemen will have to be further assessed.*

- Fuel costs at market prices (that is, gas versus HFO or diesel);
- Operational efficiency of plant;
- Capital costs;
- Gas pipeline transportation costs to the plant; and
- Conversion costs.[51]

The calculations in Table 3.3 are based on an average long-term oil price forecasts of US$30/bbl and sets out an indicative economic netback calculation for the proposed 400 MW OCGT Marber I (or alternatively a new CCGT plant on the Red Sea coast) compared to the newly constructed oil-fired power plant.

Table 3.3: Economic Netback for Natural Gas for New OCGT and CCGT Plant

Plant Characteristics	Average Existing Oil-fired Plant in Yemen	Maber OCGT	Hudaidah CCGT
Generating Capacity (MW)	400	400	400
Load Factor	75%	75%	75%
Output (GWh/y)	2,628	2,628	2,628
Heat Rate (BTU/kWh)*	10,035	10,035	6,200
Thermal Efficiency	34%	34%	55%
Capital Cost (US$/kW)	800	700	700
Plant Cost (US$ MM)	240	280	280
Life of the Plant (years)	30	30	30
Per Unit Capital Cost (US¢/kWh)	1.4	0.7	0.7
Fuel Price (US$/MMBTU)	**5.3**	**6.3**	**10.2**
Per Unit Fuel Price (US¢/kWh)	5.3	6.3	6.3
Other O&M Costs (US¢/kWh)	0.7	0.4	0.4
Generation Costs (US¢/kWh)	**7.4**	**7.4**	**7.4**
Pipeline Transportation Costs (US$/MMBTU)		**0.8**	**0.8**
Economic Netback at Gas Plant (US$/MMBTU)		**5.5**	**9.4**

*Note: *3412 BTU/Efficiency Rate.*

Source: The World Bank calculations based on data provided by PEC.

[51] *A gas conversion involves changes to the engine, the control system and power plant systems. The conversion of the engine is mainly restricted to the installation of a gas fuel system on the engine. For the plant systems, it is necessary to install gas feed and gas handling systems, to change the exhaust gas system and to replace the power plant control and automation system.*

The Marber plant is a proposed new plant and, hence, the capital cost component of the oil-fired plant is considered in the economic netback analysis. Thermal efficiency of both the oil and open cycle gas-fired plant are similar whereas it is higher at combined cycle gas plant. Per unit capital and O&M costs of OCGT and CCGT plants tend to be lower.[52] Since it is a new plant, no conversion costs are applied. Assuming an average gas transportation tariff of US$0.8/MMBTU, the economic netback is around US$5.5/MMBTU (US$6.3 minus US$0.8) for the OCGT plant and US$9.4/MMBTU (US$10.2-US$0.8) for a CCGT plant at the Red Sea coast, possibly Hudaidah.

As a consequence, the maximum price GoY can charge for its gas to be sold to the Marber plant (or the WTP of the OCGT plant operator) is up to US$5.5/MMBTU. Due to the efficiency gains, the maximum price a CCGT plant operator on the coast would pay for the gas is US$9.4/MMBTU.

This demonstrates that unless there are technical constraints or relatively higher costs of bringing the generated electricity from the coast to the load centers, it may be preferable to construct new power generation capacity, for example, in Hudaidah, to capitalize on the efficiency gains of a CCGT plant.[53]

Table 3.4 sets out an economic netback analysis for the conversion of the existing 98 MW Hizyaz units near Sana'a which currently runs on HFO to an OCGT plant. For an existing plant, capital costs are treated as "sunk" costs and consequently excluded from the netback calculation. Adding O&M costs leads to total generation costs of US¢6.0/kWh. Netting those generation costs back to a typical OCGT plant and deducting US$0.8/MMBTU gas transportation costs and plant conversion costs of US$0.2/MMBTU, gives an economic netback of US$3.9/MMBTU.[54]

This indicative analysis demonstrates that for existing and new plants, even at very conservative oil price forecasts of US$30/bbl, a potential generator would be willing to pay up to US$5.5/MMBTU for natural gas at Maber and up to US$3.9/MMBTU at Hizyaz. In case, the Maber plant is moved to the coast, for example, Hodaidah, and a combined cycle gas plant is being constructed, a potential investor would be willing to pay up to US$9.4/MMBTU for natural gas. These economic netbacks are much higher than the opportunity costs of US$2.6/MMBTU of exporting the remaining gas reserves as set out in Table 2.5.

The Marib Plant and Gas Pipeline

GoY has commissioned the construction of the Marib OCGT plant in two phases. Phase I, currently under construction, has an installed generation capacity of 360 MW and is jointly financed by the Arab Fund, the Saudi Fund and GoY. GoY has further secured financing for the extension of the Marib plant by adding an additional 400 MW of generation capacity. It is understood that the plant extension will be

[52] *Unit costs for OCGT plants tend to be lower than for CCGT plants and are around US$500/kW. However, for the purpose of the calculations in this report, the authors adopted the costs figures provided by PEC.*

[53] *CCGT and desalination plants tend to go side by side, and there are some technical efficiency gains which can be achieved between these two plants. Typically, desalination plants use the waste heat from CCGT plant for the desalination process and provide raw water for make-up to the steam cycle.*

[54] *Assuming Hizyaz pays opportunity costs of US$2.6/MMBTU for the Marib gas, the break-even point for making the conversion economically viable will require average long-term crude oil price of at least US$8/bbl.*

Table 3.4: Hizyaz 1 & 2 and Economic Netback for Natural Gas

Plant Characteristics	Hizyaz Oil-fired Plant	Hizyaz OCGT
Generating Capacity (MW)	98	98
Load Factor	75%	75%
Output (GWh/y)	645	645
Heat Rate (BTU/kWh)*	10,035	10,035
Thermal Efficiency	34%	34%
Capital Cost (US$/kW)	800	700
Plant Cost (US$ MM)	78	68
Life of the Plant (years)	30	30
Per Unit Capital Cost (US¢/kWh)	1.4	0.7
Fuel Price (US$/MMBTU)	**5.3**	**4.9**
Per Unit Fuel Price (US¢/kWh)	5.3	4.9
Other O&M Costs (US¢/kWh)	0.7	0.4
Generation Costs (US¢/kWh)	**6.0**	**6.0**
Pipeline Transportation Costs (US$/MMBTU)		**0.8**
Economic Netback at Gas Plant (US$/MMBTU)		**4.1**

*Note: *3412 BTU/Efficiency Rate.*
Source: The World Bank calculations based on data provided by PEC.

financed by several institutions, including the Arab Fund, Saudi and Oman funds.

PEC finances, constructs and owns the 3 km gas pipeline between the Safir gas field and the Marib plants. This is a dedicated pipeline and will not be connected with the NGP that is envisaged to run from the gas fields at Safir to Maber, Sana'a and along the coast south of Aden.

GoY, as the owner of all proven gas reserves in Yemen, has allocated proven gas reserves to the plant from the Marib field (Block 18) and is currently negotiating a long-term GSA with PEC. It is understood that a price in the range of US¢50-80/MMBTU is being negotiated.

Table 3.5 gives an indication of potential generation costs of the Marib OCGT plants which could be as low as US¢1.8/kWh. Transmitting the generated electricity from the Marib plant to the market will require new and upgraded power T&D infrastructure which has to be included in the supplied electricity costs from that plant at the customer end. Consequently, the US¢1.8/kWh does not reflect the economic cost of supplying the generated electricity at the customer end.

Table 3.5: Power Generation Costs of New Marib OCGT Plants

Plant Characteristics	Marib OCGT Plant I
Generating Capacity (MW)	360
Load Factor	80%
Output (GWh/y)	2,523
Heat Rate (BTU/kWh)	10,004
Thermal Efficiency	34%
Capital Cost (US$/kW)	700
Plant Cost (US$ MM)	252
Life of the Plant (years)	30
Per Unit Capital Cost (US¢/kWh)	0.7
Fuel Price (US$/MMBTU)	**0.5**
Per Unit Fuel Price (US¢/kWh)	0.5
Other O&M Costs (US¢/kWh)	0.6
Generation Costs (US¢/kWh)	**1.8**

Note: The World Bank calculations based on data provided by PEC.

The National Gas Pipeline (NGP)

The Two-phase Approach

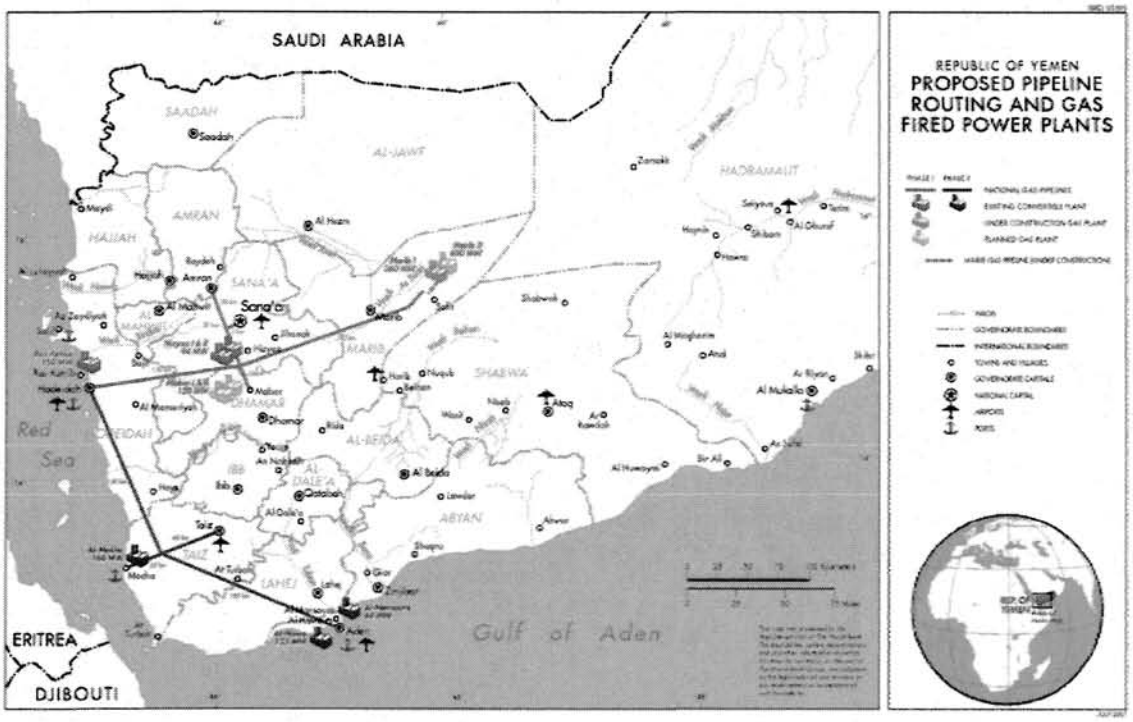
Several studies have been carried out to date on the economic and financial viability of domestic gas pipeline development in Yemen. In the most recent study by Ramboll, the construction of a national high-pressure transmission pipeline, the NGP, from the gas field at Safir toward markets in Maber and in and around Sana'a/Amran and eventually south to Aden along the costal areas via Hudaidah was proposed.

Based on the gradual development of gas demand in various parts of Yemen, the construction of the NGP was proposed in two phases. Figure 3.2 sets out schematically the two phases and the existing and new power generation plants along the pipeline routing.

Phase I of the NGP is envisaged to run from the Safer-operated gas fields in Safir, following the Ras Isa oil pipeline to the cross-section point on the highway between Sana'a and Maber. This Phase also includes proposed spur lines northwards to Sana'a and the cement plant in Amran, and south, the planned power plants at Maber. The pipeline then further runs in parallel with the oil pipeline until Bajil and finally to Hudaidah.

Phase II is envisaged to follow the Red Sea coastal line from Hudaidah passing Al-Mokha (with spur lines to Taizz and Al-Mokha) and from here along the Gulf of Aden to Little Aden (Aden Refinery) and Aden city.

Figure 3.2: Proposed Pipeline Routing and Gas-fired Power Plants



Source: The World Bank, based on information provided by Ramboll, June 2005, and PEC, September 2006.

Potential Gas Demand of Power Generation

While some of existing and new industries in Yemen may develop in the near future as major gas customers, the economic and financial viability of the NGP will depend on the power sector as an anchor customer.

Of the existing power plants that could be converted, only Ras Katnib (located near Hudaidah) and Hizyaz-1 and 2 (located near Sana'a) fall in Phase I. The construction of the Maber power plant(s) is important for the economics of the pipeline because there is no other sizable customer on the pipeline route that may justify the construction of the 300-km Phase I of the NGP.

However, PEC should reassess shifting the proposed Maber plant(s) to the Red Sea coast. This would provide access to cooling water and would enable the construction of a CCGT plant (possibly in combination with a desalination plant). This would substantially reduce power generation costs and improve the economics of the NGP through lower gas volume uptake per kWh of electricity generated and would require a smaller sizing of the NGP with subsequent lower construction costs and gas transportation tariffs.

One GW of electricity generated from an OCGT plant requires 1.6 Bcm of natural gas, assuming a 35 percent efficiency factor. In contrast, 1 GW of electricity generated from a CCGT plant only requires 1 Bcm of gas, assuming a 55 percent

efficiency factor. The exact gas volumes will further depend on the age of the plant, geographic location and the exact technology used. Table 3.6 sets out potential annual gas demand of the power sector in both phases using exclusively OCGT technology.

annually or about 17 Bcm (0.6 Tcf) over a 30-year life period.

In total, 1.8 GW of gas-fired generation capacity from existing and new plants would require 2.9 Bcm of natural gas annually, or

Table 3.6: Potential Annual Gas Demand of Power Plants Using OCGT Technology

	Electricity (MW)	Natural Gas Consumption (Mcm*)
Phase I		
Hizyaz I & II	96	154
Ras Kadnib	150	240
Maber I & II	1,200	1,920
Total	**1,446**	**2,314**
Phase II		
Al-Mokha	160	256
Al-Hiswa	125	200
Al-Mansoura	64	102
Total	**349**	**558**
Marib I & II	760	1,216

Sources: PEC and the World Bank calculations.
**Million Cubic Meters.*

The conversion of existing plants in Phase I in Hizyaz and Ras Kadnib would require 400 Mcm of gas annually. The proposed 1.2 GW capacity of Maber I & II plants would require 1.9 Bcm of natural gas annually and would be by far the largest customer on the NGP. If technically feasible, moving the proposed 1,200 MW OCGT plant from Maber to the Red Sea coast, and using CCGT technology, annual gas consumption of the plant could be reduced from 1.9 Bcm to 1.2 Bcm.

The conversion of the existing power plants in Phase II, namely Al-Mokha, Al-Hiswa and Al-Mansoura, would require 560 Mcm

87 Bcm (or 3.1 Tcf) over a 30-year life period of plants from the NGP. This is based on the power sector using only OCGT plants. (As discussed above, by potentially using CCGT technology for 1.2 GW of generation capacity, this would reduce total annual gas consumption to 2.1 Bcm, or 63 Bcm – or 2.2 Tcf – over a 30-year life period.)

The cement sector is the second largest existing gas customer, and it was estimated that the existing cement plants in Amran and Bajil (Hudaidah) could use about 80 Mcm of natural gas annually or 2.4 Bcm (0.08 Tcf) assuming a 30-year life period of the plants.

Table 3.7: The Economic Feasibility of the National Gas Pipeline

Discount Rate: 12% Oil Price: US$25/bbl	Internal Rate of Return (IRR)	Net Present Value (NPV) in US$ Million	Unit Transportation Costs (US$/MMBTU)
Full System (Phase I & II)	26	760	0.83
Phase II (Hudaidah to Aden)	15	81	1.34

Source: Ramboll, June 2006.

Al-Mokha, Al-Hiswa and Al-Mansoura (both located in Aden) fall into Phase II of the gas conversion plan.

The Marib plant is not directly supplied from the NGP, but from a dedicated pipeline, the Marib Gas Pipeline. Marib I requires about 17 Bcm (0.6 Tcf) over a 30-year life period and Marib II, if constructed, an additional 19 Bcm (0.7 Tcf). In total, Marib I and II would require 36 Bcm (1.3 Tcf) of natural gas over a 30-year period from the Marib Gas Pipeline.

It is understood that GoY has allocated 5.2 Tcf (or 150 Bcm) of existing gas reserves for the domestic market. The converted and new power plants on the Marib Gas Pipeline and the NGP would require about 4.5 Tcf (123 Bcm) of natural gas over a 30-year period[55] (or 3.6 Tcf – 99 Bcm) if CCGT technology is used for 1.2 GW of new generation capacity). This would leave 0.7 Tcf (37 Bcm) of proven gas reserves for the development of the nonpower sector with natural gas. In case CCGT technology is used, the remaining gas reserves are 1.6 Tcf or 45 Bcm, respectively.

The Economics of the National Gas Pipeline

The total construction costs of the NGP were estimated at US$850 million in August 2005.[56] Although pipeline material costs are constantly changing, those estimates provide a good indication of the overall investment requirements. It is further understood that under the YLNG deal, the YLNG partnership will provide up to US$110 million toward the construction of the NGP. That funding will not be sufficient to fully construct Phase I and/or Phase II of the pipeline, and substantial additional resources will be required.

The economic feasibility of the NGP is set out in Table 3.7. Using gas demand forecasts until 2025, a discount rate of 12 percent and an oil price of US$25/bbl, Ramboll calculated an Internal Rate of Return (IRR) of 26 percent if both Phase I and Phase II of the NGP are constructed, deriving an average gas transportation tariff of US$0.83/MMBTU. The analysis further highlights that with an IRR of 15 percent, the economics of Phase II is less favorable than Phase I.[57]

It is important to point out that the consultant's calculations do not include the YLNG contribution which would reduce the capital expenditure requirements for the NGP (that is, US$110 million) which would further substantially reduce the unit gas transportation costs of US$0.83/MMBTU.

Further, if CCGT technology is used for new power generation, the associated lower volume

[55] *1 Bcm of natural gas is about 6.5 million bbl[s] of crude oil. (1 bbl of oil equivalent is 5,487 Cubic Feet [cf] or 157 Cubic Meter [m³] of natural gas).*
[56] *Ramboll, Natural Gas Utilization Study, Pricing and Economic Viability, June 2005.*
[57] *Ibid., 27.*

uptake may enable a reduction in the sizing of the pipeline that could further reduce construction costs and transportation tariffs.

From the data and information available, one can calculate the *maximum gas transportation tariff* that an existing power plant planning to switch to natural gas would be willing to pay assuming that the plant operator has to pay economic costs for the gas.

This analysis is set out in Table 3.8. The economic netback of an existing HFO plant switching to natural gas was calculated in Table 2.7 at US$4.9/MMBTU, minus the plant conversion costs of US$ 0.2/MMBTU, minus the opportunity cost of the gas at the wellhead of US$2.6/MMBTU.

Table 3.8: Maximum Gas Transportation Tariff on National Gas Pipeline

	US$/MMBTU
Economic netback of existing HFO plant	4.9
• Natural gas conversion cost	0.2
• Economic cost of gas (well head)	2.6
Maximum Gas Transportation Tariff	**2.1**

Source: The World Bank calculations.

Hence, an existing plant is willing to pay, on an average, up to US$2.1/MMBTU for gas transportation tariffs on the NGP. This compares favorably with the actual unit transportation tariff of US$0.83/MMBTU calculated by the consultant for constructing the NGP.

These calculations are indicative but demonstrate that even if the gas is priced at opportunity costs and unit gas transportation costs are much higher than US$0.8/MMBTU due to higher pipeline capital costs and lower gas volume uptake, the power sector still has substantial economic and financial incentives for switching from HFO and for building new gas-fired power plants.

It further indicates that GoY has substantial leeway to create financial incentives for potential private investors to construct and operate the NGP by offering attractive transportation tariff arrangements.

Establishment of an Attractive Gas Industry Structure

The design of the future gas market structure and clarification on "who" is allowed to do "what" in the Yemeni downstream gas market is of key importance to attract investors. In principle, the gas sector should be organized to allow for multiple buyers and sellers to enter the market, promote the growth of the power, industrial, commercial and residential sectors, and provide an economic and reliable source of energy to meet future demand in Yemen. At the same time, the market structure has to be attractive to private investors to develop the NGP and any additional T&D network in the future.[58]

The Current Natural Gas Industry Structure

To date, the government undertakes various roles in the gas sector, many of which conflict with principles necessary to assure private sector participation in the market.

GoY, through its fully-owned subsidiary Safer, is the owner of the Marib gas reserves at Block 18 and the sole monopoly gas supplier in the Yemeni market. The MOM is in the process of signing a long-term GSA to provide the Marib power plant, operated by the State-owned PEC, with natural gas. The 3-km Marib Gas Pipeline between the field at Safir and the plant will be

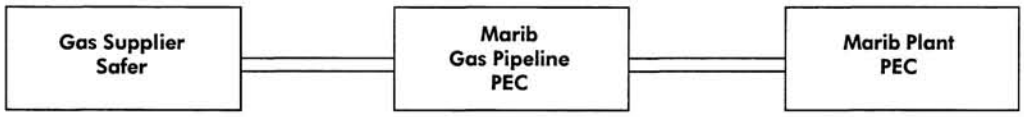
[58] *Garcia, R.,* Guidelines for Developing the Domestic Gas Market in Yemen, *November 2006.*

financed, constructed and operated by PEC. The current State-owned gas industry structure is schematically set out in Figure 3.3.

GoY has further indicated the desire to be involved in the downstream gas sector and has also expressed an interest that the private sector leads the development of greenfield gas pipeline development, in particular, the construction of the NGP.

At this stage, the terms of private sector participation remains unclear. GoY will have to set out a clear gas market framework that specifies *"who"* is allowed to carry out *"what"* in the gas chain with defined roles and responsibilities of the various players. That framework includes a clear vision on the potential role of the public and private sector in the gas market. The next section discusses areas that GoY has to address while developing a framework for an efficient development of the domestic market and private sector participation in the construction of the NGP.

Figure 3.3: The Current Gas Industry Structure



The Gas Market Players

The domestic gas chain in Yemen consists of four key activities, namely: (i) domestic gas production; (ii) gas T&D; (iii) gas shipping and supply; and (iv) gas consumption. The roles and responsibility of each participant in these activities will have to be addressed when designing an efficient gas market structure for Yemen.

- **Gas Production**

Under the current Model PSAs 2005, GoY is the sole owner of all gas in Yemen. Operators are allowed to use the gas for reinjection to increase reservoir pressure and/or flare associated gas for operational purposes and or use gas at the platform to operate machinery.

In theory, operators also have the opportunity to market associated and nonassociated gas domestically or internationally. In practice, this requires that an operator sign a GSA(s) with an end user(s) within six months of finding the gas. The PSA further specifies that if an operator cannot secure such an agreement within that time period, the operator's right to market the gas will cease and will be fully transferred to the government.

In addition to the GSA, operators will also have to sign a GDA with the MOM. If associated gas is found, it is specified in the PSA that YGC would own not less than 60 percent of the marketed gas and its share and costs of marketing that gas would be fully carried out by the operator. For nonassociated gas, there is no prescribed minimum share specification in the PSA and the operator and the MOM may negotiate that share under the GDA.

Oil and gas companies that find associated or nonassociated gas fields in the future face large challenges to sign GSA(s) and a GDA within the time period specified. From an organizational or gas market structure perspective, this leads to GoY monopolizing the supply of gas *into* the domestic market and prevents the emergence of multiple gas producers/suppliers. The emergence of multiple gas supplies is important to creating an efficient downstream gas market.

There is also an urgent need to support integration between natural gas and power production in Yemen to encourage investors in gas production. Yemen needs substantial new generation capacity to meet its growing energy demand and a policy that supports private investment in power generation by IPPs may further provide comfort to oil and gas companies to increase E&P activities.

In the future, operators may discover additional associated and nonassociated gas fields along or near the proposed NGP which they may wish to sell domestically. Hence, upstream contractual arrangements should be readdressed to allow for the emergence of multiple gas producers/suppliers in the future.

- **Gas Transmission**[59]

There are basically two options for organizing gas transmission in a market, namely, as "merchant" or "nonmerchant" pipelines.

In the case of a nonmerchant pipeline, transmission companies are only allowed to carry out the function of transporting third party gas from the injection point into the transmission network to the city gates (where the gas enters the distribution system).[60] Long-term GTC(s) are signed between the pipeline company and the agents who buy and sell the gas. Those agents can be gas producers, shippers, suppliers or large customers. Transmission companies will only be able to buy and sell gas for operational purposes (for example, to maintain the line-pack of the system, for compression, for system balancing in case of nomination overruns).

In a *merchant pipeline*, the pipeline owner and operator also carries out the commercial functions of a shipper and/or supplier, namely the buying and selling of the commodity natural gas and arranging for transportation on its own (and potential other) pipeline network.

Merchant pipelines are common in developed and less developed markets. However, to avoid conflicts of interests, in competitive gas markets there is a clear separation (or unbundling) of the merchant and transportation function of gas transmission pipelines.[61] Such a separation will ensure that costs cannot be shifted by the pipeline from the commercial activity of buying and selling of natural gas to the regulated transport business.

For the NGP (and any future gas transmission pipeline development), a potential private investor should be allowed to operate a merchant pipeline to create incentives for its participation in the market. In addition, the operator of the NGP may also be allowed to carry out other functions in the market and no cross-ownership restriction may apply. Separate GSA and GTC contracts and regulatory accounts should be put in place to ensure transparency and avoid cost-shifting between regulated and unregulated businesses.

In addition, cross-ownership should only be allowed if the regulatory framework adopted will ensure the avoidance of monopoly power against third parties.

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[59] *Foundation Contracts and Greenfield Gas Pipeline Developments: Experience from the United States and Other Jurisdictions, A Final Report to the Australian Consumer and Competition Commission (ACCC), Gerner, F., Richards, C., Houston G., NERA, March 2002.*

[60] *In Great Britain, National Grid owns and operates the national transmission system, but is not licensed to act as a shipper or supplier of natural gas. Hence, National Grid does not have any incentive to discriminate among shippers and suppliers who sell gas to final customers but focuses on maximizing its revenues by increasing network utilization.*

[61] *In the United States, for example, the Federal Energy Regulatory Commission (FERC) requires separate contracts for the purchase of gas and the transportation of gas for interstate pipelines under Order No. 636.*

- **Gas Distribution**

The economics of gas distribution in Yemen is yet to be established. Once the NGP is constructed, it may be viable to build some distribution network to convert commercial load, especially from more expensive alternative fuels such as fuel oil and, in particular, LPG. Considering that there is no heating load, the economic and financial viability of connecting residential households may be challenging. However, this will have to be assessed by the market and an attractive and efficient gas market framework should allow agents to enter the market and develop, own and operate gas distribution network.

In most markets around the world, gas distribution companies act as both pipeline owners/operators and gas suppliers to final customers. There are economics of scale[62] and economics of scope[63] between the pipeline and supply functions on the distribution network, including metering and billing, and international experience has demonstrated that greenfield gas distribution pipeline developers tend to prefer to carry out both functions simultaneously.[64] Governments tend to provide geographic exclusivity to greenfield distribution companies for the pipeline and supply function and, thus, encourage investment.

No separate commodity and transportation contracts should be required on the distribution network and the distributor should be allowed to offer a "bundled" service to customers. Further, no cross-ownership restrictions may apply and a potential gas distributor may also be allowed to carry out other activities in the gas market. Cross-ownership should only be allowed if the regulatory framework adopted will ensure the avoidance of monopoly power against third parties. Separate regulatory accounts for pipeline distribution and supply activities should be established to allow regulatory oversight, prevent cost-shifting and increase transparency in the market.

- **Gas Shipping and Supply**

A gas shipper is an individual or organization who arranges with the gas transporter for the conveyance of gas on the transporter's pipeline network. Gas supply means activities relating to the purchase of gas from a producer, gas merchant pipeline or shipper and sale of that gas to end users.[65]

In more developed and competitive gas markets, gas shippers play an important role as aggregator of supply and demand, buying and selling bulk gas and arranging for shipping the gas on the network.[66] Gas shippers can also carry out other functions in the market, including acting as suppliers. Large customers and distribution companies often act as shippers in their own right in developed gas markets.

At the initial stage, the MOM will be the sole supplier and shipper of natural gas. As the

[62] *The situation that arises when the cost of performing multiple business functions simultaneously is more efficient than performing each business function independently.*

[63] *Reduction in the average cost of a product in the long term, resulting from an expanded level of output. One reason is that overheads and other fixed costs can be spread over more units of output.*

[64] *Turkey's Experience with Greenfield Gas Distribution Development since 2003, The World Bank, January 2007; Greenfield Gas Distribution, Cross-Country Experience, The World Bank, January 2007.*

[65] *In principle, a supplier should be able to buy natural gas directly from a shipper. A supplier could also directly buy gas from a producer, arrange for shipment through the pipeline network and sell it to final customers. Under such a scenario, a supplier would, by definition, also be a shipper.*

[66] *In the British gas market, there are currently about 90 licensed gas shippers including upstream operators, foreign utilities, banks, power generators and gas suppliers.*

market develops, and if further gas is being found, other gas suppliers should be allowed to sell gas directly to large customers and utilize the gas infrastructure system.[67]

Considering the few players in the market in Yemen, and the small size of the future gas market, it is unlikely that sole gas shippers will evolve in the near future. The market framework for Yemen should, however, be flexible enough to allow for multiple gas shippers and suppliers to develop. A gas supplier and shipper should also be allowed, in principle, to own transmission and/or distribution network. However, there has to be a separation between the regulated and unregulated activities.

- **Gas Customer**

PEC will be the anchor gas customer in Yemen. There is potential for other State-owned and private companies to consume gas in the near future, including the cement sector. Large customers should be able to negotiate and sign long-term GSA(s) and GTC(s) with the pipeline owner and operator and gas suppliers/shippers.

Once the gas distribution network has been developed, commercial and residential customers could be supplied by distribution companies, and with whom they would get into a contractual arrangement.

In summary, to incentivize private participation in the development of the NGP and the Yemeni gas market, there should not be any cross-ownership restrictions on private companies to operate in any segment of the gas chain. However, to ensure transparency and protect customers, there must be accounting separation for the natural monopoly transmission and/or distribution businesses and the potentially competitive production/supply and shipping businesses.

A Future Gas Market Structure

It is envisaged that in the future gas market, the following activities and agents should be allowed to emerge, including

- Multiple gas producers who can sell their gas directly into the downstream market to customers;
- Merchant gas transmission company (ies) that own, operate and maintain their gas network;
- Integrated gas distribution and supply company(ies) that have geographic exclusivity;
- Independent shipper(s) and supplier(s) that are eligible to supply customers and that have TPA to the network; and
- Large industrial customers who have the freedom to choose their own gas supplier.

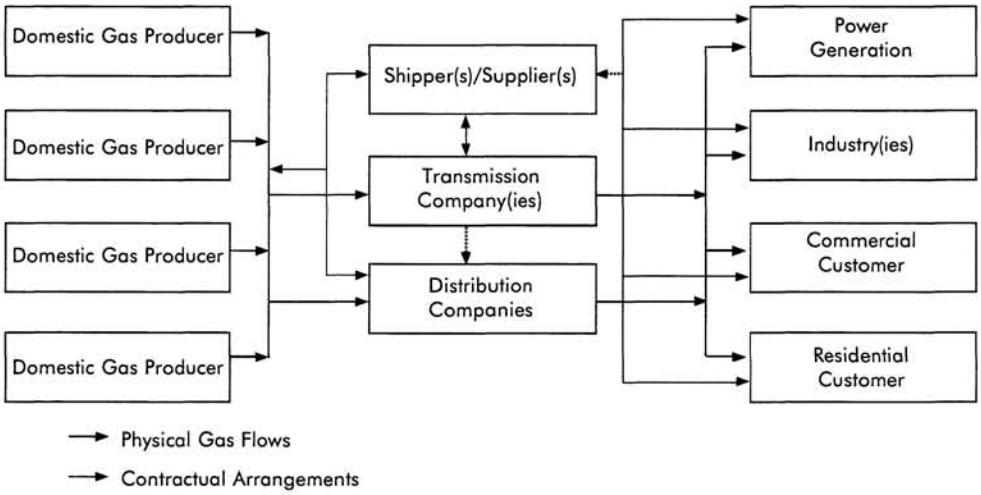
Not all of those functions will emerge in the short- to medium-term. However, the dynamics of gas markets change rapidly, and even for a small market like Yemen, a small gas finding near existing gas infrastructure can change the dynamics of the market. An efficient gas market structure must ensure that it is flexible for new market entrants and, at the same time, protect customers from potential market abuses of participants. Figure 3.4 sets out schematically an attractive future gas market structure for Yemen.

To date, the gas market in Yemen is dominated by the public sector. GoY has indicated that it aims to get the private participation[68] in the

[67] *In Great Britain, there are about 30 domestic gas suppliers (that is, for small residential and commercial customers) and about 60 business gas suppliers. Most shippers also operate in the gas supply market. A full list of gas suppliers can be found on www.ukpower.co.uk/suppliers.*

[68] *Under private participation, the private company must assume operating risk during the operational period or assume development and operating risk during the contract period. In addition, the operator must consist of one or more corporate entities with significant private equity participation that are separate from any government agency.*

Figure 3.4: A Future Gas Market Structure for Yemen



downstream gas sector and, in particular, in the construction of the NGP. This report recommends that the private sector should be allowed to participate in all parts of the gas chain.

Private Participation in the Development of the National Gas Pipeline[69]

However, the most immediate area where GoY seeks private investment is for the construction of the NGP. Gas transportation construction and operation are new activities in Yemen and international companies can provide substantial expertise in this area on both the commercial and operational aspects of running the business.

International experience shows that private participants are willing to invest in gas transmission networks in developing countries. Table 3.9 provides an indication of investment volumes and regional focus of private investment in gas transmission in the period 1990 to 2005. Most private investment projects were carried out in Latin America. In MENA, there were two major gas transmission developments with a total investment volume of about US$3 billion.

In principle, there are four types of private investment in gas transportation infrastructure, including (i) divestures; (ii) concessions; (iii) operation and management contracts; and (iv) greenfield projects.

In a divestiture, a private consortium buys an equity stake in a SOE. The private entity stake

Table 3.9: Natural Gas Transmission Pipeline Investment by Region 1990-2005

	East Asia and Pacific	Europe and Central Asia	Latin America and Caribbean	Middle East and North Africa	South Asia	Sub-Saharan Africa	Total Investment
US$ million	3,962	3,666	11,407	2,927	571	354	22,887
Project Number	7	5	24	2	1	2	41

Source: Private Participation in Infrastructure (PPI) Project Database, PPIAF.

[69] *Private Participation in Infrastructure (PPI) Project Database, Public-Private Infrastructure Advisory Facility (PPIAF), The World Bank, http://ppi.worldbank.org/index.aspx.*

may or may not imply private management. Under a concession, a private entity takes over the management of a SOE for a given period during which it may assume significant investment risk. In an operations and management contract (which includes management contract and leases), the private entity takes over the management of the SOE for a given period of time. It may also include significant investment by the private entity under the contractual arrangements.

For Yemen, the greenfield project-type of investment is the most relevant. Under greenfield, a private entity or a public-private Joint Venture (JV)/partnership build and operate a new facility. Table 3.10 provides an overview of the various types of private participation in developing countries. It indicates that, over a 15-year period, private participation in greenfield transmission pipeline development was widespread whereas management/lease contracts and concession did not really play any major role.

Table 3.10: Natural Gas Transmission Pipeline by Investment-type 1990-2005

	Concession	Divesture	Greenfield	Management/Lease Contract	Total
US$ million	600	6,665	15,621	0	22,886
Project Number	1	7	33	0	41

Source: Private Participation in Infrastructure (PPI) Project Database, PPIAF.

There are various options for designing a relevant private sector-led contracts for greenfield projects including:

- **Build, Lease and Own (BLO):** A private sponsor builds a new facility largely at its own risk, transfers ownership to the government, leases the facility from the government and operates it at its own risk, then receives full ownership of the facility at the end of the concession period. The government usually provides revenue guarantees through long-term take-or-pay contracts for bulk supply facilities or minimum traffic revenue guarantees;
- **Build, Own, Transfer, or Build, Own, Operate, Transfer (BOT or BOOT):** A private sponsor builds a new facility at its own risk, owns and operates the facility at its own risk, then transfers ownership of the facility to the government at the end of the concession period. The government usually provides revenue guarantees through long-term take-or-pay contracts for bulk supply facilities or minimum traffic revenue guarantees;
- **Build, Own, and Operate (BOO):** A private sponsor builds a new facility at its own risk, then owns and operates the facility at its own risk. The government usually provides revenue guarantees through long-term take-or-pay contracts for bulk supply facilities or minimum traffic revenue guarantees.
- **Merchant:** A private sponsor builds a new facility in a liberalized market in which the government provides no revenue guarantees. The private developer assumes construction, operating and market risk for the project.

The boundaries between these categories are not always clear, and some projects have features of more than one category. Getting further clarification and consensus on the most appropriate form of private participation in the NGP is the most important next step for GoY to take in the process of developing the domestic gas market.

Key Contract/Market Design Issues[70]

To attract private participation in the financing of the NGP and ensure the development of an efficient gas market that will protect customers from anticompetitive behavior, a set of broad principles should be adopted in the design of the market and the contract(s), including:

- Unbundling of competitive from monopoly activities;
- Regulatory accounts;
- Separate contractual arrangements;
- Third Party Access;
- Open season;
- Pipeline capacity;
- Gas pricing structure;
- Transportation tariffs; and
- Other relevant concepts and provisions.

Each of these will be discussed below in more detail.

- **Unbundling of Competitive from Monopoly Activities**

In order to encourage private participation, an industry structure that allows gas producers, shippers and suppliers to compete on a level playing field with each other has to be allowed to develop. Hence, introduction of effective market structures that prevent anti-competitive behavior should be developed.

Anti-competitive conduct occurs when the monopoly part of the vertically integrated business (that is, T&D) behaves in a way that gives its competitive business units (that is supply and shipping and production) an advantage over its competitors. Separation or unbundling seeks to prevent this type of anti-competitive behavior. This is achieved through the isolation of the monopoly elements of a vertically integrated business from the competitive elements, thereby reducing both incentives and opportunities for anticompetitive conduct.

While companies should be allowed to act in various parts of the gas chain in Yemen, it is imperative that there is a clear separation of their activities. In principle, there are four types of separation or unbundling methods: including (i) financial; (ii) physical; (iii) legal; and (iv) full ownership.

Financial separation has effects at the accounting level and requires separate accounts for the monopoly and competitive activities of the gas chain. The major objective of financial separation is to enable the company and the regulator to identify the costs of each business activity and report these costs in a transparent way to avoid "cost-shifting" among business activities in a more competitive market.[71]

Physical separation is a more stringent form of unbundling. In addition to providing separate accounts, physical separation requires having separate offices in separate buildings, or, if within the same building, by locating offices on separate floors and providing restricted access of staff and restricting information-sharing. A business unit within a utility that is physically

[70] *The analysis presented in this section has been largely drawn from Gerner, F., Richards, C., Houston G., Foundation Contracts and Greenfield Gas Pipeline Developments: Experience from the United States and Other Jurisdictions: A Report to the Australian Consumer and Competition Commission (ACCC), NERA, March 2002.*

[71] *Cost-shifting occurs where a utility attributes the cost of providing its unregulated service to a regulated service. The effect is that the utility is able to provide its unregulated service more cheaply, and customers of the regulated service must bear higher costs. In addition, the utility gains an unfair advantage over its competitors in the unregulated part of its business.*

separated is likely to have separate management for that unit.

Legal separation incorporates all the characteristics of financial and physical separation. However, it is a stricter version of physical separation requiring the formation of different, independent business activities. The advantage of this form of separation is that it facilitates a clear audit trail, allows for greater transparency and promotes independent business activities of the legally separated entity.[72]

The most stringent form of unbundling involves *full ownership* divesture of a network business activity implying a new ownership arrangement independent of competitive gas activities.

International experience shows that effective and meaningful vertical separation is an important prerequisite for gas market development. In the case of Yemen and for the construction of the NGP, the minimum of financial separation is recommended.

- **Regulatory Accounts**

Regulation of gas markets require information and financial data from companies to be able to make coherent and credible regulatory decisions. Companies have incentives not to conceal relevant information that is required to regulate the business. This problem is commonly referred to as information asymmetry that arises when companies have important information that the regulator does not have. In principle, accounts can be divided into: (i) statutory; and (ii) regulatory accounts.

Publicly listed companies use statutory accounts as the basis for preparing annual financial statements. In essence, statutory accounts are for tax purposes whereas financial statements will be based on international accounting standards to make them comparable for investors and creditors.[73]

Statutory accounts and financial statements do not provide sufficient information necessary for regulating monopoly businesses. Therefore, regulated companies should prepare and submit regulatory accounts. The main focus of regulatory accounts is to provide more detailed and focused information about regulated businesses for use by the regulatory agency.

Most jurisdictions around the world require companies to prepare regulatory accounts as part of their license condition. It is recommended that GoY develops regulatory accounting guidelines that provide guidance in the preparation of regulatory accounts for companies.

- **Separation of Contractual Arrangements**

Vertical unbundling or separation of monopoly from competitive gas activities also requires contractual separation of the "commodity" gas from the "activity" of transporting or conveying of gas on the pipeline network.

Commodity contracts are defined as contracts between parties for the purchase and sale of the commodity natural gas. *Transportation contracts* are contracts for the conveyance of gas on a pipeline network. Without separate contractual arrangements, it is not possible to effectively unbundle the potentially competitive

[72] *One could also have a legal separation without a physical separation. Two fully separate companies could operate out of the same physical location and with common economic goals.*

[73] *The accounting process encompasses three principal financial statements: The balance sheet shows assets, liabilities and stockholder's equity. The income statement reflects revenues, expenses, and gains and losses. The statement of cash flow includes operating, investing and financing inflows and outflows.*

from the natural monopoly element of the gas chain.[74]

For Yemen, it is recommended that for the NGP, separate contracts for transportation – that is GTC(s) – and for the commodity gas – that is GSA(s) – are being offered. This will not only allow customers to compare gas and transportation tariffs, but will also enable new entrants (such as gas producers and suppliers) to arrange for separate GTC(s) to sell gas directly to customers.

- **Open Access to the National Gas Pipeline**

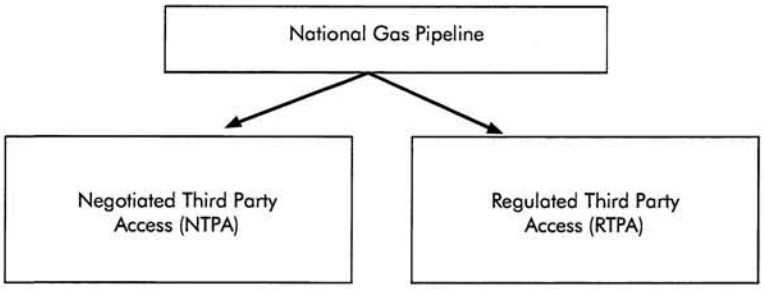
Open, nondiscriminatory access to the transmission (and distribution) network is a prerequisite for the development of a dynamic downstream gas sector. This is of particular importance in markets where transport is not fully divested from other activities. *Openness* ensures that the transportation network is open to other parties than the transporter. *Nondiscrimination* is an obligation on part of the transporter not to favor any party for the usage of transportation network. However, that does not imply that a transporter must offer the same terms and conditions to shippers for using the pipeline.

There are mainly two ways of arranging access to transportation network namely, Negotiated Third Party Access (NTPA) and Regulated Third Party Access (RTPA). Figure 3.5 sets out those options graphically.

In case of *NTPA*, the owner and operator of the transportation network "negotiates" terms and conditions with a potential shipper(s) and/or supplier(s) to convey gas on its transportation network. If the transporter is a fully unbundled company whose only responsibility is to transport gas on its network (like National Grid in the United Kingdom), it has an incentive to increase usage of its pipeline by third parties to maximize its revenues. Being a sole transport company, the transporter does not have any conflict of interest, and it is likely that negotiation of access can lead to optimal outcomes. This can allow for negotiated prices and discounts on standard pipeline tariffs that can maximize the usage and the economic benefits from the pipeline.

The situation is different in case of gas markets that continue to be vertically integrated (or not fully unbundled). In such market environments, where the gas transporter operates a merchant pipeline and is also involved in upstream

Figure 3.5: Options for Accessing the National Gas Pipeline



[74] *Prior to introducing competition, vertically integrated gas companies around the world had a tendency to sell natural gas to final customers at "bundled" prices, which incorporate the commodity gas and the transportation of gas into a single tariff. As a consequence, customers were unable to distinguish between the cost of the commodity gas and the cost of the transportation service. Separation through contractual arrangements not only allows customers to get a better understanding of the costs involved in buying and transporting gas, but also forces network owners to operate the transportation business as a separate cost center.*

purchase of gas and supply activities, NTPA does not lead to efficient outcomes. The main reasons being that the transporter has a conflict of interest in allowing access to its pipeline to third parties, as that would allow other parties to compete in the supply of gas to final customers.

In North America, the use of *RTPA* is widespread. While there is scope for tariffs to be negotiated, shippers retain a right to be served on regulated tariffs. Such a regime prevents the balance of power from leaning toward either party in the negotiations. In Europe, the European Gas Directive allows the adoption of a system of either NTPA or RTPA. Further, in Europe, most new gas systems will be able to obtain derogation for up to 10 years according to the Directive.[75] Most countries currently follow negotiated TPA rules, and the lack of common rules release vertically integrated transporters in most European markets from some regulatory constraints. While this freedom increases the short-term bargaining position of the gas transporter, it can also lead to multiple disputes, hinder the introduction of effective competition and be potentially damaging to investment incentives.

Hence, a system of RTPA not only guarantees nondiscriminatory access to the network, but also ensures that the pipeline owner and operator do not abuse its market position to block the development of competition in the shipping and supply of gas by refusing new entrants access to the pipeline network. However, the strict application of RTPA can restrict desirable outcomes such as negotiation for lower transportation tariffs for marginal users under underutilized pipeline network. NTPA can provide stronger incentives and better alignment with economic goals.

The most appropriate access for the NGP will partly depend on whether or not the future owner of the pipeline will carry out other activities in the Yemeni gas market. It will also depend on how transportation tariffs are being structured, but generally a system based on clearly defined terms and conditions of TPA to the pipeline is recommended, and that can be achieved under both, a RTPA and NTPA regime.

- **The Open Season Process**

The open season essentially consists of "requests for capacity" from potential new customers on the NGP. In this way, an open season enables a private pipeline developer to assess the demand for its proposed new pipeline network. The open season does not deal with the issue of transportation tariffs for new pipeline development; its principle purpose is to get an indication of shippers demand for new capacity.

A pipeline operator normally is allowed to require a minimum term for new transportation capacity from customers on a new pipeline development. During the open season process, an interested shipper must complete a "letter of intent," which states that the shipper is contemplating signing a pro forma GTC with the private operator within a specified number of days after the close of the open season. Typically, GTC(s) are signed before the construction of the pipeline which specifies the terms and conditions, including tariffs and capacity, for shipping gas on the pipeline. It is recommended that an open season process be conducted for the NGP.

- **Pipeline Capacity**

International experience shows that greenfield transmission network developed is driven by transportation contracts with "firm" capacity rights. This is mainly based on the fact that a private pipeline developer is unlikely to be able to finance the construction of the new capacity without shippers who are committed to pay for it.

[75] *A derogation is the right of the pipeline owner to refuse access to its pipeline network for a specific period.*

A firm transportation contract provides the shipper with the right to use reserved, prespecified and defined capacity on a pipeline to ship gas. In general, firm transportation contracts define a specific volume of capacity over a certain specified distance between specific receipt and delivsery locations, or a possible set of locations.[76]

It is very likely that initially only the power sector will be in a position to sign long-term GSA(s) and GTC(s) with firm capacity. Some additional uncontracted (spare) capacity in the pipeline will be required and ensure that future customers, in particular, industrial plants and the commercial sector, will be able to contract for capacity on the NGP. Spare capacity in this context means all noncontracted or noncommitted capacity as part of the open season in the process of developing the NGP. The exact volume of the spare capacity will depend on an assessment of the future demand on the pipeline.

For the construction of the NGP, it is recommended that firm capacity rights are offered as part of the GTC(s). Further, the pipeline owners should be allowed to create some reasonable excess capacity in the pipeline and recover those additional costs from the gas tariff.

- **Gas Pricing Structure**

The integration of the gas and power markets is crucial for the development of the NGP. If power generators have to sign long-term take-or-pay contracts with upstream operators for the supply of the "commodity" gas, they may tend to mitigate that take-or-pay risk by requiring a minimum offtake of power under their long-term power sales agreements. These back-to-back contracts should ensure that the risk of mismatch between fuel purchase and fuel consumption can be avoided. Two-part pricing (capacity and energy) is the norm for power sales agreements, because it avoids the incentives for uneconomic dispatch which could occur under a single-part tariff. Hence, a gas pricing structure in GSA(s) and power purchase agreements should be developed that is compatible with least-cost dispatch of power plants, and will likely require the establishment of a two-part tariff structure.

- **Transportation Tariffs**

Gas network costs are driven by the need to meet peak demand. These are fixed costs of increasing network capacity. The variable costs of network operation are generally quite small in relation to the fixed costs. Therefore, customers who have a peaky load shape are causing more cost on the system than customers with a flat or base load demand shape. Hence, costs would have to be divided into fixed and variable costs which can translate into a capacity and commodity charging regime for system users.

It is assumed that gas demand overall will be quite flat in Yemen (there is relatively little seasonal difference for power demand) and the costs of within-day balancing are probably quite small as well. There could, nevertheless, be significantly different costs of supplying different categories of customers (for example, power plants versus industrial load).

GoY could provide a long-term tariff to the potential investor that is "fixed" and not directly linked to volume throughout. Alternatively, a two-part tariff design could be adopted. This is a structure under which one part is a periodic availability charge that covers fixed costs, and the other part is applied to the actual amount of service that is provided and covers variable costs.

[76] *In more developed gas markets, shippers can also obtain "interruptible" transportation service or by trading firm or interruptible capacity in a secondary (capacity release) market. However, interruptible service is less relevant for greenfield developments.*

In principle, the level of tariffs should allow the efficient service provider to recover costs, including a reasonable return on assets. A transportation tariff that is mostly fixed may be more attractive to a private pipeline developer. The advantage of having a fixed tariff for a greenfield pipeline is that this will not only simplify the supervision of the GTC(s), but also encourage the pipeline operator to further seek gas connections from industry and others to increase the profit margin. More gas uptake, in contrast, would benefit Yemen as industry would switch away from more expensive and/or polluting alternative fuel sources such as HFO.

A two-part tariff is more complicated to administer, but would further reduce overall tariffs as more users take up gas in the long run. Such a tariff could be linked to "blue sky" provisions (discussed next) that create incentives for the pipeline operator to avoid undersizing of pipelines. This will avoid asymmetric risks where the pipeline bears the costs if volumes are less than expected but does not enjoy the benefits of higher-than expected volumes.

Costs of transmission networks also vary with distance and length of pipelines and pressure of supply and a locational or distance related charging regime could be adopted. Distance related pricing provides signal on whether to expand the network especially into remote areas.[77] However, there are often social and political factors that prevent governments from introducing such pricing regimes. Further, to simplify the tariff regime on the NGP, GoY may consider establishing a uniform or postage-stamp pricing regime.

The economic analysis above has demonstrated that there is substantial leeway in the design (both size and structure) of gas transportation tariffs on the NGP. To create an attractive regime for a potential private investor, the exact design will require more methodological discussions and analysis.

- **Other Relevant Concepts and Provisions for Greenfield Pipelines**

"Blue sky" is a term referring to the possibility of a private pipeline operator realising financial rewards arising from a greater-than-anticipated increase in future gas throughput on a pipeline than expected at the outset. This provision may provide a good incentive for the developer of the NGP to actively seek additional customers on the pipeline beyond the power sector. Benefits-sharing mechanisms might be negotiated between shippers and the pipeline to share some of those benefits. Blue sky only arises where regulated transportation tariffs are volume-related rather than fully capacity-related.

Most Favoured Nation (MFN) clauses in GTC(s) have the potential to prevent a pipeline owner and operator from offering different tariffs for transportation services to shippers on the pipeline. Price discrimination on a pipeline network generally increases economic efficiency through its encouragement of increased network utilization and in many developed gas markets with a wide network of gas transmission networks, such as the U.S., price discrimination tends to be encouraged.[78] In some larger gas markets in developing countries, such as Mexico and Argentina, MFN clauses exist in

[77] *As in the case of transmission, each potential gas distribution area in Yemen may have different costs. Key costs drivers for distribution are the customer density of the region (which principally affects the pipeline length per customer) and the demand volumes. The proportion of small commercial or residential customers in the mix will lead to much higher unit costs than areas with larger industrial loads.*

[78] *In the U.S., MFN clauses are not included in gas transportation contracts. However, under FERC rules, interstate pipeline network owners are only allowed to offer different tariffs for transportation services to shippers on a pipeline who are not "similarly situated." Similarly, situated shippers are interpreted as shippers that take service over the same part of the pipeline and have similar alternatives options. See Alternative Ratemaking Policy Statement: Alternatives to Traditional Cost-of-Service Ratemaking for Natural Gas Pipelines, 74 FERC 61,076, 1996.*

transportation contracts. MFN clauses and blue sky provisions could be applied in Yemen. The appropriateness of these terms will depend on the final transportation tariff structure and pipeline capacity arrangements and incentive regime.

Development of an Efficient Regulatory Regime

There are four key regulatory questions that have to be addressed, namely *"why"* do we have to regulate the gas industry, *"what"* regulation intends to achieve, "what" parts of the gas market has to be regulated and "how" should regulation be conducted.

Why Regulation of the Gas Sector is Necessary

The primary method of organising private sector activity is through the operation of a market. Provided that certain basic rules are defined (principally, who owns what), markets allow producers to compete against one another, unfettered by any constraints other than the conditions of supply and demand. Under those conditions, competition will produce the best outcome.

However, if some criteria are not met, competition produces undesirable outcomes. For example, in case of monopolistic market structures, competition is not feasible and a profit-maximizing monopoly will raise its prices above its costs, to increase profits. High prices do not only allow the firm to earn profits that are higher than they need to be, but also discourage demand that could be met at a cost that customers are willing to pay . Both factors result in the loss of potential benefits to society and provide governments with a reason to intervene in the operation of the market.

Some monopolies exist because of the intrinsic economic conditions of production. These monopolies are called *"natural monopolies"* and require permanent regulation of their behavior, if the undesirable effects of monopoly are to be avoided.

Natural gas pipelines are natural monopolies and are characterized by large economies of scale (relative to the size of the market), such that one firm meeting total demand is always cheaper than the total cost of two or more firms, each meeting a share of total demand. In such conditions, continuing competition in the market is either inefficient or impossible and could lead to pipeline duplication and loss of social welfare.

Economic regulation is the process for setting terms and conditions for access where they cannot be set through competition.

What Regulation Intends to Achieve

Profit-maximizing monopolies restrict the supply of a product or service in order to drive up the price and to raise their profits. The starting point for regulation is simply the desire to increase output and to bring prices back down toward the level of costs, including the costs of capital.[79]

Regulatory interventions increase *allocative efficiency*, that is, the efficiency with which customers choose which products and services to consume (and, hence, the efficiency with which resources is allocated to production). Setting prices in line with costs helps customers to allocate their expenditure efficiently – and prevents monopoly profits.[80]

[79] *Regulatory economists divide the accounting profits of a regulated company into two parts: the cost of capital, or the rate of return required to reimburse investors, sometimes known as the "normal profit"; and any rent or "supernormal profit" earned above the cost of capital.*

[80] *However, regulation can also result in allocative inefficiency if it discourages or prohibits price differentiation and discounts that would avoid deterring use of the pipeline where users are willing to pay more than the marginal costs, but less than the average costs. This is particularly relevant for gas pipelines where the difference between marginal costs and long-term average costs can be very large.*

To increase efficiency overall, monopoly regulation must also avoid causing an unnecessary increase in production costs. If prices are set equal to costs (including the cost of capital) at all times, then the monopolist has no incentive to minimize costs, since increase in cost do not cause profits to fall. Such a regime would allow costs to rise and would reduce *productive efficiency*, that is, the efficiency with which the company produces a given level of output. Therefore, regulatory regimes should offer incentive for regulated companies to reduce their costs, essentially by reducing profits if the company is inefficient, and increasing profits if the company is efficient.

The main terms of monopoly regulation are:[81]

- Legal protection of a monopoly in return for an obligation to meet all reasonable demands for the service;
- A promise that the company will recover its prudently incurred costs, balanced by a restriction on revenues or prices that prevents the company from earning monopoly profits; and
- A set of minimum quality standards that prevents the company from profiting by reducing the quality of service (as a substitute for rising prices).

What in the Gas Sector should be Regulated

In competitive gas markets (such as Australia, the U.S. and the U.K.), where there are multiple buyers and sellers of natural gas and the industry is "unbundled" the only areas that are subject to economic regulation are the natural monopoly elements of the gas chain, namely the gas pipeline T&D businesses. The competitive elements where multiple importers, producers, shippers and suppliers compete to sell gas to numerous customers are unregulated. Regulation is not required as efficient competition creates optimal outcomes.

In some developed gas markets, full retail competition has been established and gas prices for residential households are also determined by competition (that is, the United Kingdom). The regulator simply has an oversight role to ensure that retail competition is effective and does not interfere in the market as long as this is ensured.

In less competitive or uncompetitive markets, a gas regulator also has to supervise the import, supply and shipping of gas to protect customers from monopoly power. In Yemen, there will be a very limited number of buyers and sellers of gas, and efficient competition is unlikely to evolve for the supply and shipping of natural gas in the short- to medium-term future. Hence, regulatory oversight of all parts of the gas chain will be required for the foreseeable future.

How should the Gas Sector be Regulated

A regulatory framework needs to be developed for the gas sector in Yemen that is congruent with the potential size of the gas market and existing governance structures, and consistent with international best practice. To achieve this, instruments used to implement a regulatory framework must be able to provide stable and legally enforceable regulation in order to promote the certainty that is needed to attract private sector investment for pipeline development. Further, the instrument(s) should involve a degree of prescription in defining the framework to ensure it is workable and effective.

[81] *Shuttleworth, Graham,* The Principles of Good Monopoly Regulation, *NERA, February 2001.*

GoY has two major options for setting up an efficient regulatory framework for the gas market, namely:

- Full legislation; and
- Regulation by contract.
- **Full Legislation**

Legislation is typically used in the regulation of utilities industries in advanced economies globally and in larger energy markets in developing countries (for example, Indonesia, Nigeria, Argentina), but has not been used widely for governing the energy sector in general, and the oil and gas sector in particular, in Yemen.[82]

Under this approach, primary legislation (such as a gas law) sets out the overarching principles, rights and obligations of the participants in the market, and this is enacted by the legislature (that is, parliament). The legislation is the "first-order instrument" and tends to state broad general principles and concepts that are unlikely to be subject to change for a reasonably long period. Table 3.11 sets out what a potential gas law tends to cover.

Legislation is typically implemented through a combination of subordinate instruments, such as decrees, regulations, licenses and enforcement guidelines, which spell out more specific procedures and rules. These subordinate instruments tend to be more specific, yet, easier to amend and adopt to changing industry conditions. Matters covered in subordinate instruments are set out in Table 3.12.

The advantages of legislation are that it provides a robust and certain framework for industry administration and allows more detailed regulatory arrangements to be established in less rigid subordinate instruments. However, the rigor of the implementation process means that there may be a substantial delay in implementation.[83]

Table 3.11: Coverage of Potential Gas Law

• Coverage of the regulatory framework
• Prohibition of regulated activities without license
• Authority to issue licenses and criteria for issuing licenses
• Obligation to provide Third Party Access
• Broad pricing principles
• Broad regulatory processes
• Right to independent dispute resolution
• Rights of appeal

[82] *The upstream oil sector is basically governed by contract through PSAs.*

[83] *An alternative to the full legislation approach is to implement the regulatory framework through one or more decrees. Under this model, the enabling provisions and broad principles are provided through a decree. The detailed arrangements may then be set out in further implementing decrees, licenses and/or enforcement guidelines. The advantage of the decree approach is that it is promulgated by the government, and therefore, avoids the lengthy approval processes necessary to pass legislation through the Yemeni parliament. On the negative side, a decree, due to its less rigorous nature, does not provide the same degree of certainty as legislation.*

Table 3.12: Coverage of Subordinate Instruments

• Procedures for application and issuing of licenses
• Technical standards (for example, safety, health, metering)
• Detailed price regulation methods and formulae
• Standard license conditions
• Detailed regulatory decision-making processes
• Regulatory accounting requirements

Hence, while a robust framework may be achieved in the very long term, the lengthy period of uncertainty in the medium term, arising from delays in the development and passing of legislation, may have a significantly harmful effect on development of a gas market.

- **Regulation by Contract**

The other option for implementation of the regulatory framework is regulation by contract. This approach involves GoY and the owners and/or operators of gas pipelines establishing a regulatory regime that applies by force of contract. All aspects of the regulation set out above would thus be set forth in a contract.

The advantages of this approach are that it does not involve the delays inherent in the legislative option and allows the application of principles that are unique to the particular pipeline situation. However, the disadvantages are that it requires consensus of both GoY and the pipeline owner/operator, so may still take some time to implement.

Furthermore, another new project will require negotiation of another unique agreement and revision of any provisions over time will require further negotiation. In addition, a contract approach is less transparent than regulation by legislation and may make it more difficult to ensure uniformity and fairness of regulation.

A regulation by legislation approach tends to be more appropriate when the gas industry is already well established. To improve the efficiency of the industry, governments often restructure and break up existing gas markets and newly assign roles and responsibilities for market participants by passing primary legislation (and subsequent subregulations). Further, the size of the future gas market and required gas pipeline infrastructure developments are decisive. In large gas markets, such as Indonesia or Brazil, as the market grows, additional gas pipeline network will be required to serve customers throughout the country. To ensure the development of a competitive gas market, and avoid different regulatory regimes for each gas pipeline, a regulatory approach based on full legislation is preferable. Otherwise, the risk is that regulation is tailored to each particular project, making regulatory activity (adjudication during conflicts and issuing new legislation) difficult to be exercised consistently over time and as the market further develops.

In contrast, regulation by contract is often used when a government wishes to grant a "special status" to ensure a greenfield pipeline project is being realized as soon as possible, and to make it financially attractive for private investor. In Yemen, the biggest net benefit to society is to get the NGP built and through fuel-

switching savings by the power sector. Setting up a regulatory framework based on full legislation would delay that process for many years and, hence, regulation by contract may be more suitable.[84]

Further, once the NGP has been built, there will be limited opportunities for additional gas transmission development and any additional transmission pipeline could be regulated by contract. There are also limited gas distribution network development opportunities in Yemen in the near future, and contracts are likely to be the most efficient means to ensure distribution network development down the road.[85]

- **Licenses and Concessions**

GoY should issue licenses/concessions for *each* activity carried out in the market, including gas supply, shipping and T&D. A license grants companies the right to participate in the gas market and sets out their respective roles and obligations. Concessions are arrangements in which a firm obtains, from the government, the long-term right to provide a service under conditions of signification market power by creating geographic exclusivity rights. Concessions are often granted in gas distribution.

Separate T&D licenses/concessions should be issued. Transmission licenses tend not to have regional exclusivity whereas distribution concessions generally have exclusivity on a regional basis. In principle, a network company could hold both a transmission license and a distribution concession and also hold gas supplier and/or shipper licenses. Distribution companies often carry out supply functions, and should also be issued a supply license.

The proposed licensing/concession regime, and who is allowed to carry out what function in the market, should be consistent with the gas market structure set out above. There should be no ownership restrictions and barriers to participate in any part of the gas chain. However, licenses/concessions will set out unbundling requirements and the need to establish separate regulatory accounts, and these and other responsibilities will be set out in the respective authorizations.

The licensing instrument could also be used to develop a "middle-ground" option distinguished from regulation by legislation and regulation by contract for the NGP and other transmission network development whereby the license conditions attached to the approval of a greenfield pipeline development sets out the access regime and includes broad regulatory principles such as pricing principles, rights of appeal, rights of independent dispute resolution, and so on. The pipeline developer could, then, offer a long-term access regime and further clarify the terms and conditions of access, for example, technical standards, detailed pricing methods and formulae. Once those terms and conditions are agreed, the access regime would effectively be the contract between the pipeline and users that contain the necessary regulatory provisions.

Who should Regulate

Standard theory on utility regulation requires the establishment of an "independent" regulatory agency. Although the independent regulator model is a widely accepted best practice model of regulation for developed economies and mature gas markets, it is unrealistic to expect

[84] *Regulation by contract is also consistent with Yemen's upstream regulatory experience in oil and gas. The MOM issues authorizations to perform the various activities in the hydrocarbon sector, and regulatory provisions for the upstream are provided in the oil/gas-sharing agreements.*

[85] *Natural gas could potentially replace LPG in urban and semiurban areas for the domestic sector in and around Sana'a and Aden, but it is unlikely that distribution network development will be economically and financially viable in more rural areas.*

that the model can be adopted immediately in all countries and at all times. This is particularly the case in countries with limited institutional capacity. Further establishing such an independent agency to supervise the gas market requires substantial financial resources for creating and running the agency, hiring qualified staff, political will and time. It further requires regulatory powers to develop, implement and supervise compliance with regulations. In countries which do not have those institutional and legal capacities, more attention needs to be directed to good-fit rather than best-practice regulatory systems.[86]

In Yemen, the government has various roles that are prone to create conflict of interests. GoY owns gas reserves (through Safer), finances and potentially operates the Marib Gas Pipeline (through PEC) and will initially be the sole customer of the gas (through PEC). At the same time, GoY is responsible for developing energy policies (including natural gas policies) which are conducted through its ministries and government units, and is also responsible for promoting private sector participation. While the creation of an independent regulatory agency is impractical, creating some separation between the political and economic functions in the gas market, and creating a suitable regulatory regime that provides some comfort to market participants and potential private investors, is necessary.

The active participation of the Ministry of Electricity (MOE) in setting up a suitable regulatory regime for the gas market is paramount considering that the existing and projected gas-fired plants will anchor the development of the NGP. Close cooperation between the two ministries (namely, MOM and MOE) is crucial to: (a) ensure that the investment plan for new gas-fired power plants (and for the conversion of existing generators) matches the timing of the construction of the NGP; and to (b) assist in structuring suitable terms and conditions of the long-term GSA and GTC and licenses.

For the foreseeable future, the Yemeni gas market will comprise a limited number of pipelines and the conditions and terms of access, including tariffs, can be covered by contracts and the licenses/concessions. The primary regulatory task would be to verify that compliance with the contract(s)/license(s)/ concession(s) and, in principle, that task could be carried out by: (a) a separate government agency within a ministry(ies); (b) existing government agency(ies); and (c) a newly created government authority.

To ensure that regulatory activity is conducted in a transparent manner, a limited set of functions could be assigned to that government agency under the direct jurisdiction of GoY. If it is embedded within an existing government agency(ies), committees could be established comprising civil servants from MOM, MOE and other relevant stakeholder (for example, the Ministry of Industry and government agencies that are responsible for private sector investment, private sector representation).

This relevant government agency(ies) could develop implement and supervise a regulatory regime based on contracts, and could also be responsible for issuing licenses and concessions. The agency(ies) could further develop broad regulatory principles that would govern the gas market and would engage in the monitoring of compliance with technical and safety standards and obligations set out in licenses and concession contracts (for example, mandatory

[86] See Handbook for Evaluating Infrastructure Regulatory Systems, *Brown, A., Stern, J., and Tenenbaum, B., The World Bank, Washington DC, 2006 and Groom, E., Halpern, J., Ehrhardt, D., Explanatory Notes on Key Topics in the Regulation of Water and Sanitation Services, Water Supply and Sanitation Sector Board Discussion Paper Series, Paper No. 6, June 2006.*

investments, information requirements, disclosure of technical and commercial information). Further, the agency(ies) could advice the government in technical and commercial matters that may be needed for the purpose of granting new concessions and licenses. Credibility of the regulatory regime could be enhanced in some or all of the monitoring functions, for example, GTC(s) on the NGP would be carried out by international auditors on an annual or biannual basis.[87]

In the longer run and given the close link between the gas and power sectors in Yemen, the establishment of a "joint" government or independent regulatory agency may also be considered. There are economies of scope and scale in establishing a joint gas and power regulatory agency, for example, in the areas of technical regulation and price-setting. However, the establishment of such an agency should not delay the development of the gas market and, in particular, the construction of the NGP.

Conclusions

Yemen has a unique opportunity to reduce the oil dependency of its domestic market by switching to natural gas, in particular, gas-to-power. It was estimated that over a 30-year period, about 800 million bbl[s] of crude oil could be saved by the power sector and those could be earmarked for exports to boost government revenues. Natural gas will also provide current and emerging industries with an opportunity to have access to relatively cheap, clean and reliable source of energy.

The development of the domestic gas market will require the construction of the NGP and the economic and financial viability of that pipeline was demonstrated in this Chapter. To avoid further constraints on public financing and considering the large investment requirements, the private sector, or a public-private partnership, should lead the development of the greenfield project.

Timing is a key factor and the earlier the NGP is constructed, the higher the net economic benefits to the Yemeni economy. Consequently, a regulatory regime and gas market structure has to be put in place that is practical, attractive to private investors, consistent with international best practice, suitable for the small size of the gas market and in conformity with Yemen's legal and institutional practice and history of governing the utilities sector.

The current gas market is dominated by the State and the government should allow for private participation in all parts of the gas chain. It is recommended that no cross-ownership restrictions apply and market participants are allowed to participate in all parts of the gas chain, including gas production, transmission, distribution, shipping, supply and consumption. This would mean that the owner and operator of the NGP should also be allowed to be a gas producer, buyer and seller of the gas or customer. However, to ensure transparency and protection of end users and to prevent anti-competitive behavior, companies who engage in several gas businesses along the gas chain will have to unbundle and prepare separate accounts for each business activity.

The analysis has further demonstrated that GoY has substantial leeway in designing a market and regulatory regime for the NGP that will make it attractive for private investors to

[87] *Yemen may not yet be in a position where the legal arrangements allow regulation by contract (or licenses) administered solely be a government agency(ies), or the courts in case of disputes. One possibility is to provide contract(s)/license(s) supervision and enforcement by an agency outside the country, for example, an international arbitration body or an international group of experts. While this still leaves major problems of enforcement with the country, the increased transparency may enhance private investors' willingness to participate in the market.*

participate. It is proposed that separate commodity and transportation contracts, TPA rules, an open season process, firm capacity rights and an attractive tariff structure be adopted.

Yemen is a very small gas market and has limited history and expertise in regulating network businesses. An approach based on full legislation (gas law, subregulations and guidelines) for developing the domestic gas market is likely to be a lengthy process and will further delay the construction of the NGP. It is not a good idea to waste valuable time that could be used in the implementation of the project in trying to pass a law and creating subsequent regulations and, consequently, "regulation by contract" should be adopted.

The future development of the gas sector will require close coordination and cooperation between the power and gas sectors. No private financier will invest if the power sector is not ready to receive gas or is unwilling to convert. In contrast, before making such a commitment and converting their appliances, the power sector has to be sure that the NGP is going to be built and that the gas and transportation tariffs are attractive. This will require long-term gas supply and gas transportation agreements between the various parties to mitigate that risk. It is further required to reform and restructure the power sector and its electricity tariff structure to ensure that PEC, the incumbent, can recover its prudently incurred cost of supply and has the financial capacity to carry out the investment to uptake gas. The government should also consider creating a framework to allow for the participation of IPPs to meet future power generation demand. Without addressing the shortcomings of the power sector, the construction of the NGP will likely be delayed.

Yemen has limited institutional capacity and effectiveness and although the independent regulator model is a widely accepted best practice model of economic regulation for developed economies and large and mature gas markets, it is unrealistic and not suitable for the development of the Yemeni gas market. A more practical approach is to carry out regulatory duties through an existing government agency(ies) and possibly mitigating some of the conflicts of interests of the government by appointing an international agency (for example, auditing company, panel of experts) to periodically review contracts to ensure compliance. However, some consideration could still be given to a joint independent gas and electricity regulatory agency to benefit from economies of scale and scope in regulation (such as technical regulation and price-setting). It is recommended that the most suitable and practical agency(ies) will be identified as part of developing the detailed regulatory contracts and overall framework.

These flexible ownership, market and regulatory arrangements will increase the incentives for private investors to participate in the market and develop the NGP and, at the same time, protect the interest of Yemeni customers.

4. Analysis of the Key Features of Proposed Legal and Fiscal Terms for the Exploration, Development and Production of Hydrocarbons

Introduction

It is expected that oil production from currently producing fields will steeply decline after 2010. The revenues that are expected to be generated by the planned LNG project will only partially offset the decline in government revenues. A higher level of exploration is considered necessary to increase the probability that sufficient reserves of gas will be found and brought to market in time to meet future domestic and international gas demand. At the same time, there may be scope for devising incentives to enhance the recovery of existing oil reserves so as to partly offset the expected decline in production.

The global nature of petroleum investments poses challenges to government policy makers who are often not in a position to make informed decisions to determine what types and levels of taxation and what types of legal arrangements can or should be applied to petroleum projects. This Chapter provides an overview of the key features of petroleum legal arrangements and fiscal systems, and outlines desirable features that the policy makers could take into consideration for application in Yemen.

The starting point of this analysis is to present alternative legal and fiscal arrangements, and to define their principal components and relative attractiveness from the points of view of the investor and of the host government. Against this backdrop, the legal and fiscal framework for petroleum operations in Yemen will be presented. Finally, features of the petroleum fiscal regime in a selected group of countries will be outlined.

Alternative Petroleum Legal and Fiscal Systems: Advantages and Disadvantages[88]

The extraction of hydrocarbons involves the transformation of nonrenewable physical assets into capital or financial assets. The initial decision to invest and the resulting allocation of revenues and benefits are greatly influenced by the content of existing legal arrangements and fiscal policies. In today's competitive market, many diverging interests must be recognized and

[88] *The analysis presented in Chapters 4 and 5 has been largely drawn from Silvana Tordo, "Fiscal Systems for Hydrocarbons: Design Issues," Working Paper Series, The World Bank, forthcoming.*

accommodated to establish an effective and attractive legal and fiscal framework for hydrocarbon E&P. No ideal or model regime is available for policy makers to adopt. Each country's circumstances, needs and objectives define the key features of an appropriate legal and fiscal framework. As these circumstances, needs and objectives are likely to change in time, the most effective and efficient legal and fiscal frameworks are those that are flexible enough to accommodate these changes.

Decisions on the design of an appropriate legal and fiscal framework can be supported by an understanding of how its various components influence decision making and outcomes.

Legal Frameworks for the Petroleum Sector

The legal basis for hydrocarbon exploration, development and production is normally set in a country's constitution.[89] Normally, the hydrocarbon law, formulated at parliamentary level, sets out the principles of law, while those provisions that do not affect principles of law, or that may need periodic adjustments (that is, technical requirements, administrative procedures, administrative fees, and so on, and so forth) are set in regulations.[90] Exploration, development and production rights in particular areas or blocks are granted by governments by means of concessions or contracts, depending on their legal systems. Where no unique policy regime exists,[91] comprehensive contractual agreements between host governments and investors are used.

Various legal systems have been developed to address the rights and obligations of the State and of the investors, as well as the ownership of the natural resources. These can be grouped under two main systems: concessionary systems (also called tax and royalty systems) and contractual systems (these include PSAs, and service and risk service contracts). Box 4.1 summarizes the key features of the two systems.

In both systems, the investor assumes all risks and costs associated with the exploration, development and production of hydrocarbons, and receives compensation adequate to the risk. Often the investment risks are assumed by oil companies rather than the State/owner of the resource. In general terms, the higher the risk of investment activities in a country, the higher the portion of the rent received by the investor. Although historical considerations influence the definition of "adequate compensation," project- specific elements and future expectations are also important. The notion may also vary during the life cycle of a project.[92]

The fundamental difference between concessionary and contractual systems relates to the ownership of the natural resources:

[89] *The consistency of the legal framework with the constitutional foundation is an important factor affecting the security and stability of the legal framework. This issue is significant, in particular because the constitutions of many countries differ significantly in the degree to which they recognize or guarantee private property rights or prohibit private parties or foreigners from acquiring property rights in general, and mineral rights in particular; vest the authority to grant petroleum rights in the state or provincial governments or agencies rather than the national government, vest the authority to regulate specific matters in special agencies (that is, environment protection) or in the executive branch (for example, taxation, foreign exchange employment, and so on) or in the judiciary (settlement of disputes). Due to the capital-intensive and long-term nature of petroleum projects, certainty of rights is particularly important for private investors.*

[90] *These are normally issued at the executive or ministerial level, and do not require the approval of the legislative branch.*

[91] *This is the case in Yemen where no hydrocarbon law exists at the national level and PSAs are negotiated between the State and the investors on a case-by-case basis and are given the force of law. This approach may be favored by those countries that face the uncertainty of entering the sector for the first time or in cases where the importance of the petroleum activity may not justify the design of unique policy regimes.*

[92] *In general terms, while geological risk begins to diminish after a discovery, the political and financial risks intensify. One of the reasons for this is that the bargaining power and the relative strength of the investors' and host government's positions shift during the cycle of petroleum exploration and development. By the time production commences, capital investment is a "sunk" cost, and facilities installed in foreign countries represent a source of vulnerability to the investor.*

Box 4.1: Key Features of Concessionary and Contractual Systems

Concessionary Systems

- In its most basic form, a concessionary system has three components: royalty; deductions (operating costs, depreciation, depletion and amortization, intangible drilling costs); and tax;
- The royalty is normally a percentage of the proceeds of the sale of hydrocarbons. It can be determined on a sliding scale whose terms may be negotiable or biddable, and paid in cash or in kind. The royalty represents a cost of doing business and is thus tax deductible;
- The definition of fiscal costs is described in the legislation of the country or in the particular concession agreement. Royalties and operating expenditures are normally expensed in the year they occur, and depreciation is calculated according to applicable legislation. Some countries allow the deduction of investment credits, interest on financing and bonuses; and
- The taxable income under a concessionary agreement may be taxed at the country's basic corporate tax rate. Special investment incentive programs and special resource taxes may also apply. Tax losses are normally carried forward until full recovery.

Contractual Systems

- Under a PSA, the contractor receives a share of production for services performed. In its most common form, a PSA has four components: royalty, cost recovery, profit oil and tax;
- Ibidem. Normally, royalties are not cost-recoverable;
- The definition of fiscal costs, as well as the amortization and depreciation rules, are described in the legislation of the country, or in the particular PSA. After payment of the royalties, the contractor is allowed to recover costs in accordance with contractual provisions. The remainder of the production is split between the host government and the oil company at a stipulated (often negotiated) rate. Often profit oil splits are based on a sliding scale (Annex 3, Box A3.1); and
- Income tax may apply or may be paid in lieu by the government or its NOC on behalf of the contractors. Income tax is calculated on taxable income (that is, revenues net of royalties, allowable costs and government share of profit oil). In most countries where cost recovery limits exist, the company's share of profit oil in any given accounting period is not the taxable base. Tax losses are normally carried forward until full recovery.

- Under a concessionary system, the title to hydrocarbons passes to the investor at the borehole. The State receives royalties and taxes in compensation for the use of the resource by the investor. Title to and ownership of equipment and installation permanently affixed to the ground and/or destined for exploration and production of hydrocarbons, generally passes to the State at the expiry, or termination, of the concession (whichever is earlier). The investor is typically responsible for abandonment; and

- Under a contractual system, the investor acquires the ownership of its share of production only at the delivery point.[93] Title to and ownership of equipment and installation permanently affixed to the ground and/or destined for E&P of hydrocarbons, generally passes to the State immediately. Furthermore, unless specific provisions have been included in the contract (or in the relevant legislation), the government (or the national oil company) is typically legally responsible for abandonment.

In both types of legal systems, the issue of ownership is particularly significant as it affects the rights and obligations of the parties and their ability to dispose off these rights. Given the risky nature of the industry, the investor's ability to share the risk by transferring all or part of its rights to other investors, and the objectivity and transparency of the conditions for government approval or denial of such transfer (including any relevant performance guarantee) is an important element of the overall attractiveness of a country's regime.

Table 4.1 summarizes the main difference between concessionary systems and PSAs.

Table 4.1: Main Difference between Concessionary Systems and Petroleum Sharing Agreements

	Concessionary Systems	Petroleum Sharing Agreements
Ownership of Nation's Mineral Resources	Held by State	Held by State
Title Transfer Point	At the Well Head	At the Export Point
Company Entitlement	Gross Production Less Royalty	Cost Oil + Profit Oil
Entitlement Percentage	Typically around 90%	Typically 50-60%
Ownership of Facilities	Held by Company	Held by the State
Management and Control	Typically Less Government Control	More Direct Government Control and Participation
Government Participation (carried working interest)	Less Likely	More Likely
Ring Fencing	Less Likely	More Likely

Source: D. Johnston, Petroleum Fiscal Systems and Production Sharing Contracts, *PennWell Books, 1994.*

[93] *Under a service contract, the contractor never acquires the title to the resource. On the contrary, he is paid a fixed or variable fee for his services. In some service contracts, the fee is paid in kind. The distinction between PSA and Risk Service Contracts lies in the nature of the payment.*

Elements of Successful Legal Frameworks

While for many years governments have focused on how to acquire control of the resources, typically resulting in the creation of national oil companies or the setting up of rigid and highly prescriptive legal frameworks, in recent years we have been observing a tendency by governments to scale back or rationalize those entities and simplify their legal frameworks.

The successful hydrocarbon reforms have tended to establish the legal framework on the following pillars:

- Definition of the role of the State;
- Security of title;
- Freedom to operate on a commercial basis (including various forms of private access to hydrocarbon resources);
- Comprehensive environmental protection requirements; and
- Competitive and stable fiscal terms.

The topics that are typically addressed in modern legal frameworks are summarized in Table 4.2

In promoting sustainable private sector-led E&P changes in the banking system, trade and labor sectors, judicial system and foreign investment regulations may be beneficial.

Although, in most countries, all matters related to petroleum exploration, development and production tend to be governed by sector-specific legislation and regulation, countries that have recently reformed their hydrocarbon sector have shown a preference for the establishment of modular legal frameworks. In these cases, all matters relating to hydrocarbon rights and their use are governed by the hydrocarbon law/regulations, all matters relating to taxation are defined in the tax code/regulations, all issues relating to environment protection are defined in the environmental law/regulations, and so on, and so forth. Thus, the hydrocarbon law incorporates other laws by reference. Modularity increases transparency and accountability, reduces administration costs and facilitates compliance.

A clear, simple and nondiscretionary legal and regulatory framework is an important factor for attracting foreign investment. This affects the entire value chain from the award of E&P rights to the disclosure of information that affects the citizenry. There are various ways of improving the transparency in the management and oversight of the sector: the standardization of the terms of E&P, the reduction of the discretion of the administrative authorities, the simplification of awarding and permitting procedures, the development of an efficient and functioning open title system, the adoption of standardized form of agreements, the predefinition of standard shape form of blocks, the granting of greater operating freedom to the contractors, the adherence to international arbitration (in particular where the local court system does not provide sufficient guarantees) and the respect of international disclosure practice are examples in this direction.

Fiscal Regimes for the Petroleum Sector: Tax and Nontax Instruments

Petroleum activities around the world are subject to a great variety of taxation instruments. These include taxes that apply to all other sectors of the economy and taxes that are specific to the oil industry. In addition, nontax forms of rent collection (like surface fees, bonuses and production sharing) are typically used.

Special provisions are often included in petroleum fiscal regimes to modify the timing or magnitude of the revenue appropriations. These provisions are normally intended as incentives designed to attract investors, or to accommodate unique attributes of a petroleum asset, or to influence the choices of the investors toward specific public policy goals. Accelerated

Table 4.2: Key Elements of Successful Petroleum Legal Frameworks

Area	Key Components
Government Authority	Ownership of natural resources; powers granted to government officers; enforcement; penalties and fines; and the authority to negotiate contracts
Access to the Acreage	Qualifications for authorization to explore, develop, produce and process; areas closed to mineral activities; areas subject to special controls or conditions; right of ingress and egress; resolution of conflicting land disputes; and the relation between surface and subsurface right holders
Exploration and Production Rights and Obligations	Extent of the E&P area; duration of the term for E&P rights; renewal of E&P rights; unitization; cancellation or termination of a right; area relinquishment; minimum work programs; security of tenure; reporting; transferability of rights and mortgageability; and surface fees
Protection of the Environment	Environmental impact assessment; environmental impact mitigation; social or community impact; monitoring and reporting; abandonment liability; reclamation; and environment sureties
Fiscal Terms	State participation; royalties; production sharing; custom duties; income tax rate and base; special petroleum taxes; other levies and taxes; gas production incentives and other incentives; ring fencing; and stability clauses

capital cost allowances,[94] depletion allowances,[95] interest deduction rules,[96] loss carry forward,[97] investment credits,[98] tax holidays[99] and stability provisions[100] are among the most commonly used special provisions.

A variety of costs are also imposed on companies that affect the profitability of their operations. Some are fairly common, while others reflect specific country's conditions. These costs include intercompany services, valuation of oil and gas,

[94] *Assets are depreciated in many ways over their expected life (useful life of equipment, economic life of the reservoir). The methods used in the industry are: (a) straight-line (equal annual deductions); (b) declining balance (straight-line depreciation calculated for the remaining value of the asset each year); (c) double declining balance (doubles straight-line depreciation for the remaining value of the asset each year); (d) sum of year digits (based on an inverted scale which is the ratio of the number of digits in a given year divided by the total of all years digits); and (e) unit of production (the capital cost of equipment, after deduction of the accumulated depreciation and of the salvage value, is multiplied by the ratio between the total production in a year and the recoverable reserves remaining at the beginning of the tax year).*

[95] *The depletion allowance is the deduction from gross income allowed to investors in exhaustible commodities (such as minerals, oil, or gas) for the depletion of the deposits. The theory behind the allowance is that an incentive is necessary to stimulate investment in this high-risk industry: as the reservoir depletes the company will need to undertake more exploration to find new reservoirs. The depletion allowance is meant to subsidize further exploration. Very few nations grant/granted depletion allowances (for example, the Barbados, Canada, Pakistan and the United States). The Filipino Participation Incentive Allowance (FPIA) is similar to a depletion allowance for various reasons, including the fact that in a global industry the depletion allowance may be used to subsidize exploration in other countries.*

[96] *Project financing is quite common for large projects or for small oil companies. Normally, interests on loans are allowed in deduction of taxable income and qualify for cost recovery. Inter-company interests may also be cost recoverable and tax deductible, if calculated on an arm-length basis.*

[97] *This refers to the ability of a company to "carry forward" losses from one year to offset tax liability in future years. When limitations apply, the loss can be carried forward for a set number of years (normally five to seven) after which the benefit expires. In most cases, unlimited loss carry forward is granted. Loss carry back are quite unusual.*

[98] *In some countries, governments provide an incentive to investors by allowing them to recover an additional percentage of tangible capital expenditure (also known as investment uplifts). In some cases, investment credits can be tax deductible.*

[100] *When capital investment in a project is considerable, host governments may grant tax holidays to investors, that is, the investors will not pay taxes for a specified period of time.*

[99] *See Box 4.2 for a description of commonly used stability provisions.*

foreign exchange regulations, domestic market obligations, government equity, performance bonds, land owner compensations, local content obligations and requirement intended to ensure good environmental practices and adequate site reclamation funding. Evaluating the impact of these costs on different investors is a very complex exercise.

The effect of a fiscal system is derived from how it impacts investment decisions[101] in either the short (capital allocation within an existing portfolio of assets) or the long (the decision to invest in or reject a project) run, in other words, its neutrality.[102] This can be expressed in terms of NPV of the expected project cash flows. Intuitively:

- All taxes reduce the NPV of a project and make it less attractive. Therefore, the higher the level of taxation, the lower the number of possible investments under prevailing market conditions;
- The timing of revenue collection is a major determinant of the NPV of a project. Fiscal systems that reduce or defer revenue collection are preferred by companies because they increase the NPV and accelerate the investment's payback; and
- The NPV is significantly influenced by the risk profile of the investment. Therefore, fiscal systems that reduce the perceived political or economic risks are preferred.

A description of the main tax and nontax instruments commonly used in the oil industry and the evaluation of their effects on government revenues and investment decision is given in Annex 3.

Elements of Good Petroleum Fiscal Regimes

In all countries, fiscal regimes are designed to maximize the value (not the volume) over time of mineral resources in terms of receipts to the treasury, while, at the same time, attracting foreign investment on a continuous basis. Host governments also have development and socioeconomic objectives (job creation, transfer of technology, development of local infrastructure, and so on, and so forth).

To achieve these objectives, more and more countries rely on flexible, stable and neutral fiscal regimes. The characteristics of these regimes are described in Box 4.2.

Key Features of Yemen's 2006 Model PSA

The analysis of any contractual and concessional arrangement needs to take into consideration how it relates to the country's legal and regulatory framework. In addition, the sector institutional set-up is an important element in analyzing the sustainability of contractual oversight and management arrangements, while the sector policy defines the target conditions for the design of the relevant fiscal terms.

Legal Framework[103] and Institutional Set-up

The constitution, in Article 8, establishes the State's ownership of natural resources. Yemen

[101] *Host governments and investors use different system measures to assess the impact of various fiscal systems. This is because, although they share the general objective of maximizing the revenue generated by a project, they also pursue a number of different objectives and face different constraints. Analyzing these objectives and constraints and the related system measures is beyond the scope of this paper. For an in-depth analysis, see Silvana Tordo, "Fiscal Systems for Hydrocarbons: Design Issues," Working Paper Series, The World Bank, forthcoming.*

[102] *For the definition of neutrality, refer Box 4.2.*

[103] *It is worth noting that a comprehensive analysis of the petroleum sector would necessitate the analysis of the regulatory body for petroleum operations and protection of the environment, as well as knowledge of the list of international convention to which Yemen is a signatory and their actual implementation. At the time of preparation of this report, this information was not available.*

Box 4.2: Key Features of Effective Fiscal Regimes

What do flexibility, neutrality and stability mean?

- A "flexible" fiscal regime is one that provides the government with an adequate share of economic rent under varying conditions of profitability;
- A "neutral" fiscal regime does not encourage overinvestment nor deter investments which would otherwise take place; and
- A "stable" fiscal regime is one that does not change over a certain period of time, or in respect of which changes are predictable.

Advantages

- One of the most important advantages of establishing a flexible structure (that is, a progressive mechanism for rent extraction) is its stability over time: as market and project conditions change over time, flexible fiscal systems limit the need for renegotiation;
- The advantage of a neutral fiscal regime is its economic efficiency. A neutral tax does not impact resource allocation. With respect to the investing company, a tax is neutral when it leaves the pretax ranking of possible investment outcomes equal to the post-tax ranking. With respect to a particular industry, a tax is neutral when it does not divert investments to or from that industry;
- In industries with longtime cycles and substantial upfront investments, stable and predictable contractual and fiscal terms are an important consideration in ranking investment opportunities, with obvious effects on a country's future prospects. The stability of the fiscal regime also impacts business confidence, and affects the level of investment in and pace of development of existing projects; and
- Contract and fiscal stability clauses are used in both concessionary and contractual systems. According to a recent study, out of the 110 countries analyzed, 77 percent offered fiscal stability protection (Baunsgaard, IMF, 2001).

does not have a unique sector law: the Petroleum Law 25 of 1976 that was in force in southern Yemen before the country's unification is no longer applied.[104] Therefore, the right to explore for and produce oil is granted to companies by means of PSAs negotiated by the MOM on behalf of the State. The PSA embodies all the terms and conditions that govern the relationship between the contractor and the State with respect to petroleum exploration, development and production operations in the country.[105] The PSA does not become effective until it is ratified by a President's decree law.[106]

Several vintages of PSAs exist that were the product of negotiations between the State and

[104] *However, the law has not been formally repealed.*

[105] *These include foreign exchange controls, tax provisions, customs and duties, and foreign investment regulations and so on, and so forth.*

[106] *Once negotiations between the MOM and the contractor are completed, the draft PSA is sent to the Special Economic Committee for evaluation. The Special Economic Committee submits its recommendations to the Council of Ministers, which, in turn, authorizes the MOM to execute the PSA. The PSA is then submitted to the Oil and Minerals Committee of the Parliament. Once approved by Parliament, the PSA is finally sent to the President of the Republic for ratification by decree law. The process takes on an average between 12 to 18 months.*

investors, and as such they contain different terms. This situation is quite common in petroleum-producing countries. Legal and fiscal frameworks tend to change over time as they adapt to changes in the country's specific circumstances, the level of national and international competition, as well as the improved understanding of the country's geological potential and of other technical matters.

The MOM ensures the application of contracts, formulates policies and implements the government's decisions on the pace of petroleum sector development by making available areas for exploration, and granting rights to explore for, develop and produce hydrocarbons. In carrying out its duties, the MOM is assisted by the PEPA, the upstream regulatory agency. The agency manages the country's data bank, supervises oil companies' activities in the country, prepares and conducts licensing rounds and negotiate the terms of PSAs on behalf of the MOM.

The State, through its national oil company, participates directly in the sector. A negotiable percentage interest, carried through exploration and development, is generally reserved to the national oil company[107] under the most recent PSAs.

The sector policy is publicly disclosed[108] and aims at diversifying the sources of revenues. The key actions envisaged by the government to accomplish the objectives of the sector policy are summarized below:

- To increase proven reserves to balance the decline in existing fields;
- To promote exploration in new areas;
- To review PSA terms and procedures in line with international petroleum industry practice;
- To grant tax and customs exemptions and free transfer of funds;
- To encourage the private sector to play an important role in all stages of hydrocarbon development; and
- To encourage the development of marginal fields through the reduction of investment requirements by:
  - Public access to existing infrastructures at nominal rates;
  - Creating new investment opportunities jointly or severally with private sector in upstream projects (PSA, gas, petroleum services) as well as downstream projects (transportation, refining);
  - Facilitating the transfer of technology by participating directly in petroleum operations through carried interests;
  - Encouraging the Yemenization of international companies operating in the country by developing plans for the replacement of the expatriate workforce; and
  - Improving the control of petroleum costs through the establishment of operating committees.

[107] *YOGC is a SOE that intervenes in different stages of the sector value chain through its six affiliates. In particular, Yemen Company (YC) holds production rights in blocks 32, 53 and in a number of exploration blocks; YGC is responsible for the development and utilization of the country's gas resources; YOC is responsible for managing government participation in oil-producing JVs with international companies; YPC is responsible for the countrywide distribution and marketing of petroleum products (except LPG); ARC and MRC are the two government-owned refineries.*

[108] *See PEPA's web site for more details at www.pepa.com.ye.*

Procedures for the Award of Petroleum Rights[109]

In Yemen, the right to explore for and produce oil in specific areas is generally awarded to the contractors through licensing rounds. Unsolicited expressions of interest and direct award are also possible.

Periodically, the PEPA publishes a list of open blocks which the government intends to offer to potential investors. This may include exploration blocks and producing blocks.[110] After receiving an expression of interest for open blocks and relevant company information (including audited financial statements), potential investors are granted access to the relevant technical data.[111] A Memorandum of Understanding (MoU) containing all relevant commercial terms is negotiated between the PEPA and the potential investors. After signature, the parties have approximately two months to finalize the terms of the PSA.

A "model" MoU highlights all negotiable terms. These are listed in Table 4.3.

To award, acreage-producing countries use different systems. Some countries have adopted rather rigid systems with very limited biddable items that affect the take,[112] other award their acreage on the basis of the work program, in some other countries "everything is negotiable." There is no model bidding system or strategy for governments to adopt. Decision on the most appropriate bidding system can be supported by an understanding of general market conditions as well as of the relative prospectivity of the areas on offer. Ultimately the resource allocation is efficient if it satisfies the national policy objectives.

Intuitively, a government would maximize its share of benefits by "letting the market work."[113] However, when almost all the parameters are negotiable, comparing alternative offers can be a difficult exercise. Estimates of oil/gas prices, prospect sizes and recovery factors, success ratios, production and engineering solutions, costs and investments, discount factors, and so on, and so forth are necessary to determine the discounted cash flow and expected monetary value associated with alternative proposals (that is, the likely value of *government take* and government participating interests). Even with good knowledge of the relevant domestic and international markets, these estimates will inevitably involve a certain level of subjectivity.

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[109] *The procedures for the award of rights and the government's role and authority are normally set forth in a country's petroleum law (complemented by regulations as appropriate). In the case of Yemen, information on awarding procedures and government authority has been collected through web site search and interviews of government officials and industry operators. The transparency of the bid evaluation procedure remains to be investigated.*

[110] *In case of producing blocks, service contracts may be considered.*

[111] *Data fees and other access condition may apply.*

[112] *The division of profit between investor and government is called the "take."*

[113] *Licensing rounds have contributed to increase competition among oil companies to the benefit of host governments. With new companies coming into the market and acreage being offered in areas that are perceived as more difficult, this has in many cases resulted in overbidding. By letting oil companies compete against each other, host governments are spared from the difficult task of determining "what the market can bear." But, as some governments have come to experience, the best bid on paper is not always a workable one.*

Table 4.3: Model MoU: Biddable Terms

Parameter	Bid Items
Exploration Period	Lengths and Number of Subperiods
First Exploration Period	• Term • Work Program Commitment • Minimum Expenditure • Relinquishment of Obligations
First Exploration Period Extension	• Term • Work Program Commitment • Financial Commitment
Second Exploration Period	• Term • Work Program Commitment • Minimum Expenditure Relinquishment of Obligations
Second Exploration Period Extension	• Term • Work Program Commitment • Financial Commitment
Royalties	• Royalty rates are linked to a sliding scale based on reaching daily production targets (oil, gas[114])
Bonuses (to be paid annually for the duration of the contract)	• Signature • Commercial Discovery (oil, gas) • Daily ProductionTargets (oil, gas) • Training • Institutional • Social Development Bonus • Research and Development Contribution • Data Bank Development Contribution
Cost Recovery Limit	Expressed in percentage of net production
Amortization Rates	Maximum rates for Exploration, Development and Operating Expenditure set in the MoU
Excess Cost Oil	Percentage to be paid directly to the State
Production Sharing	Sliding scale linked to reaching daily production targets (oil, gas)
Carried Interest through Exploration and Development	In percentage of total exploration and production interest
Duration of Production Phase	Twenty years set as maximum duration in the MoU[115]
Duration of Production Phase Extension	Five years maximum duration. New contract terms to be negotiated
Fixed Tax	3% of exploration expenditure

[114] *In the most recent version of the model MoU, the royalty rate for gas and LPG production is flat. This model MoU is being used as basis for the negotiations between the 2006 licensing round's successful bidders and the MOM, which are scheduled to start by mid-April 2007.*

[115] *In the most recent version of the model MoU, the duration of the production phase for gas is subject to discussion between the MOM and the investors during the negotiation of the relevant PSA.*

Elements of the 2006 Model PSA

In this section, the 2006 Model PSA[116] is analyzed both on its own merits, and in relation to industry good practice. The agreement was evaluated with respect to its clarity, transparency, comprehensiveness and attractiveness to investors. The structure of the fiscal terms was evaluated in terms of its respect to the principles of flexibility, neutrality and stability summarized in Box 11, and its consistency with the objectives of the government petroleum sector policy.

Overall, the 2006 Model PSA exhibits a good coverage and content and interpretation does not present particular difficulties.[117] To increase its attractiveness to international investors and to reflect the most recent trend in industry good practice, improvements could be considered in the organization of its sections,[118] and in the following areas:

- *The contractor's rights, obligations and the principles underlying the conduct of operations*, including contractors' authorization to act as deemed appropriate in case of emergency that impact safety, the environment and the interest of the parties[119] could be gathered under specific clauses. This would improve the clarity and facilitate the oversight of the contract;[120] and
- *The right to explore for and produce gas*. Oil and gas are quite different in terms of their exploration and development thresholds.[121] Gas discoveries are often noncommercial unless they contain a high percentage of liquids, they are close to an existing market, or they are very large. In addition, the cost of developing a gas field in some order of magnitude greater than that of developing an oil field. Technical and commercial factors influence the lead time from exploration to development of a gas discovery that is normally substantially longer than the lead time for an oil discovery. The world average lead time from exploration to development of gas discoveries is approximately 10 years.[122] For this reason, the duration of the production rights in a gas discovery is generally between 30 and 35 years.[123]

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[116] *A paper copy of the 2006 Model PSA was provided to the World Bank in the spring of 2006. A new model PSA is undergoing the final stages of preparation. Its finalization is expected by mid-April 2007. The new model PSA is expected to contain provisions that are specific to gas and LPG production. At the time of preparation of this report the new model PSA was not available.*

[117] *The language could be improved in some parts of the contract. In some cases, this is likely to be the product of imperfect translation from Arabic to English (for example, Articles 2.1.4, 9.1.1, 21). The following are examples of potential language improvement: (a) redundancies could be eliminated by using terms that are defined in the PSA (for example, because all activities that constitute "Development" are defined in Article 1.13, the last recital could be simplified); (b) inconsistencies could be clarified (for example, Articles 20.1 and 20.2.4, Articles 25.1 and 25.4); (c) wording could be more accurate when important rights or important potential defaults are considered; (d) in the recitals, the contractor should represent that it has the financial resources, technical competence and professional skills necessary to carry out the Petroleum Operations; (e) Article 2.1.4 (a) should ensure that the relevant rights and obligations accrued prior to termination shall survive, and so on, and so forth.*

[118] *For example, provisions that apply in different phases of exploration and development, general obligations of the contractor, general obligation of the government, and so on, and so forth could be grouped and cross-referenced as appropriate. This would improve the overall clarity and reduce the likelihood that mistakes might occur in case of amendment to these provisions as such amendment would only need to be made once.*

[119] *This is regulated under Article 29.6. However, the protection of the environment is not specifically considered among those actions which the contractor may take in emergencies and for which the relevant costs are allowed for cost recovery. In Annex F, accounting procedures, Article 2.13.2, emergency expenses to protect the environment appear to be allowed for cost recovery. To avoid discouraging the operators' responsible behavior, the wording should be clarified, and these costs should be allowed for cost recovery.*

[120] *Examples in this direction could be found in the model PSA of several countries, including Angola, Gabon and Oman.*

[121] *In some regions, development thresholds for gas can be between 5 and 15 times the size needed for an oil development.*

[122] *Daniel Johnston, 2003.*

[123] *Roughly 10 years longer than the typical production phase for oil discovery.*

Many countries are tightening their policies with respect to gas. Because it is very difficult to anticipate how large and rich in liquids a gas discovery might be, and which development option will be most suitable, many contracts contain a very simple gas clause that provides for the parties – government and investors – to negotiate the gas development terms in case a discovery is made. In some cases, general fiscal terms are set in the contract. This is normally the case in countries that have already developed a domestic market or have well established export routes.

In Yemen, the State owns both associated and nonassociated gas. To date, the contractor does not have the right to produce gas[124] but, it is allowed to use associated gas in petroleum operation and for pressure maintenance, free of charge and subject to the MOM's approval (which approval shall not be unreasonably withheld). If the MOM so requires, the contractor shall deliver associated gas to the State at the point of separation. Costs associated with the production and delivery to the MOM shall be paid by it to the contractor.[125] Associated gas that is not used in petroleum operations or by the State can be treated by the contractor in accordance with good industry practice (flaring policy is not explicitly addressed in the 2006 Model PSA).

The MOM has the right to enter into GDA(s) with third parties[126] for the export and sale of associated gas and/or its delivery to the MOM for domestic use, provided that the contractor shall be granted six months to discuss and negotiate such agreement. The 2006 Model PSA sets some boundary conditions with respect to the commercial arrangement: the State's share in the GDA shall not be less than 60 percent, and the contractor shall bear all costs related to the project which shall be cost recovered from the annual gas revenue.

If nonassociated gas is discovered, similar provisions apply. Except that, if the contractor and the government do not reach agreement on a gas development project within six months from discovery, then the contractor shall relinquish the relevant portion of acreage to the government without compensation. The contractor is, however, allowed to recover all costs incurred by it as exploration expenditure from cost oil.

Compared to other countries that aim at creating a gas sector, the provisions of the 2006 Model PSA do not provide any particular encouragement to potential investors. In addition, in the case of associated gas, the requirement for a minimum 60 percent government-carried interest in the gas development set forth in the 2006 Model PSA may not be commercially viable. Given the current lack of domestic market opportunities and the lack of infrastructure, a six-month period (the deadline set forth in the 2006 Model PSA) for evaluating gas market opportunities and negotiating the terms of a GDA may prove too short for both the contractor and the MOM. In order to attract investors and accelerate the creation of a gas market, a more collaborative approach, flexible fiscal terms or other targeted incentives may need to be considered:[127]

- *Health, safety and environment protection.* This subject is regulated under Articles 11.6 and 18.1. Although there is a general

[124] *The new model PSA is expected to address exploration, development and production rights for associated and nonassociated gas.*
[125] *Often the contractor is allowed to recover these costs as part of the cost oil. The Model PSA does not specifically allow for set-offs.*
[126] *This may present some challenges if the gas contract between the State and third parties calls for delivery schedules and technical solutions that are not fully in line with the contractor's reservoir management. To this end, the Model PSA offers some degree of protection to the contractor by mandating that the operations under the GDA shall not interfere with the contractor's petroleum operations.*
[127] *Incentives are discussed in Chapter 5 of this report.*

requirement that the contractor respects the laws and regulations applicable in Yemen with respect to environmental protection and safety as well as industry standards and practice[128] with respect to environmental matters, the environmental assessment, impact assessment and mitigation plan are not made a condition for approval[129] of the relevant field development plans and for the grant of the relevant licenses and permits.[130] The respect of international safety and labor standards has not been specifically mandated.[131] The extent to which this might be considered part of "good industry practice" has been the subject of debates among industry experts. Sureties to cover potential environmental liabilities have not been addressed in the 2006 Model PSA (or in the accounting procedure annexed to it). The accounting and cost recovery treatment of environmental mitigation structures and equipment could also be more clearly specified. The principles for land reclamation are not specified in the 2006 Model PSA;

- *Land use, right of access, compensation and resettlement*. Land use and right of access to roads and facilities are regulated under Articles 29.1, 29.3 and 29.4. The principles for compensation in case of use of privately-owned or occupied land or buildings are set out in Article 29.5. These allow the contractor to directly negotiate with the affected party on terms and conditions not substantially more onerous than those applicable to similar transactions in the relevant area and resettlement plans. If needed, compulsory sale of the relevant asset may be ordered by the government after payment of reasonable compensation. No difference is made between temporary and long-term use;

- *Ownership of data and confidentiality* should be brought in line with international standards and practice. In particular, it is not standard practice to deny the use, by the contractor, of information acquired during the term of the contract, when such use occurs after the expiry of the contract and for the contractor's internal purposes. In defining what constitutes confidential information, the use of the contractor's proprietary technology should be given adequate consideration. Disclosure to regulatory agencies, security commissions, or stock exchanges is not uncommon in the sector. In this case, confidentiality obligations need to be adjusted to accommodate these entities' operating procedures. Confidentiality and

[128] *The contract refers to rules and regulations applicable in the international petroleum industry. Reference to standards and practice would be more appropriate.*

[129] *The authority for reviewing and approving environment impact assessment and mitigation plan is not specified in the 2006 Model PSA (however, this might be specified in the relevant environmental law). Countries have adopted different approaches: some utilize a central approach where all matters related to environment are regulated in the general environmental law, others have adopted a sectoral approach where each sectoral law includes provisions related to environmental protection. Whatever the approach, the best practice is to separate the environmental approval process from the licensing function even when the environment impact assessment is required to be submitted to the Ministry of Petroleum as part of a drilling authorization or field development plan application.*

[130] *The foundation of appropriate environmental protection is to know the facts and options regarding alternative resource management strategies, alternative locations, operational and mitigation alternatives and implementation options. The Environmental Assessment is the instrument that helps define such facts and options. Only then can appropriate choices be made regarding prevention and/or mitigation of the impact of petroleum activities. A minimum standard of good practice could be the introduction of the requirement to submit: (a) an Environment Impact Study in connection with any development plan; and (b) a decommissioning plan – including environment and safety considerations – upon cessation of exploitation activities.*

[131] *Several countries have adopted either extensive regulations cross-referenced in the relevant PSA and/or have included the basic principles of in their PSAs. Angola's, Gabon's, Pakistan's, Qatar's PSAs set examples of different policies in setting the boundary conditions for proper health, safety and environment protection minimum standards.*

disclosure rights and obligations are fairly standard terms in the industry. Example can be drawn from other countries' PSAs and/or from industry standard confidentiality agreements.[132] In addition, provisions requiring transparency on State revenues received from hydrocarbon activities in accordance with internationally accepted norms could be considered;[133]

- *Cost control procedures*. Host governments have a clear interest in ensuring that the costs are kept as low as possible. Normally, contracts provide for various forms of oversight and control mechanisms. Management committees, procurement procedures, budget approval and audits are examples of these mechanisms.[134] The thresholds for approval of expenditures are particularly important: low thresholds affect the efficiency of operations.[135] During the exploration period, there is a clear incentive for the contractor to keep costs down: if no discovery is made, exploration expenditure will not be recovered. If a discovery is made, the cost recovery mechanism allows the contractor to recover its investment if sufficient revenue is generated. If a cost recovery limit is imposed, the incentive to control costs is even greater. Thus contractors' and host governments' interests are clearly aligned (although there are varying degrees of incentive depending on the choice of fiscal terms). The 2006 Model PSA's expenditure approval thresholds could afford greater freedom of operation to the contractor, as other costs control and supervision mechanisms are provided for in the contract and in the cost recovery mechanism.[136] This would reduce both the government's cost of supervision and the contractor's cost of compliance;

- *Unitization*. In case of discovery of hydrocarbons from a structure extending across the boundary of adjacent contract areas, the State has the right to ensure that, in the interest of economy, efficiency and conservation of the resource, the common deposit is developed as a single unit, on a noncompetitive basis. Common practice is to include in the law a provision giving the competent authority the right to order the affected contractors to develop such area jointly under a unitization plan approved by the competent authority. As Yemen does not have a petroleum law, the right of the MOM to order unitization should be expressly provided for in the 2006 Model PSA;

- *Abandonment* procedures and related liabilities have not been specifically addressed

[132] *The wording used in the Angola's, Qatar's, Pakistan's model PSAs and the American Institute of Petroleum Negotiators (AIPN) standard confidentiality agreement are examples of generally recognized industry practice.*

[133] *Countries that have adopted the disclosure standards envisaged by the EITI have included specific wording in their legislation and/or in PSAs (Nigeria, São Tomé and Principe, Timor-Leste, Mauritania).*

[134] *In addition, nonoperator partners also exercise their control over the operator's management of operations.*

[135] *Thresholds of US$500,000 or US$1,000,000 are not uncommon.*

[136] *As normal in contractual agreements where direct participation of the government is involved, the 2006 Model PSA provides for the establishment of joint committees. The exploration advisory committee is tasked with reviewing the work program and budget submitted by the operator and providing its advice, before work program and budgets are submitted to the MOM. Contracts related to the performance of the work program exceeding a threshold to be negotiated between the contractor and the MOM shall be approved by the MOM. Statement of expenditure shall be submitted to the MOM each quarter for review (this does not prejudice the MOM's right of audit). During the development phase, control procedures are stricter. An operating committee is set up to, inter alia, supervise implementation of the development and production operation, review and approve the work programs and budgets. The operating committee avails itself of the assistance of several subcommittees. Its internal procedures are annexed to the 2006 Model PSA. Service contracts whose value is higher than US$250,000 in case of competitive tender, or higher than US$50,000 in case of single source/contracts that are not awarded to the lowest bidder shall be approved by the MOM.*

in the 2006 Model PSA.[137] This is particularly important as title to land passes immediately to the MOM, and title to fixed and movable assets is transferred automatically as they are recovered. Although abandonment is a normal procedure under standard oilfield operating practices, abandonment obligations are normally addressed in the relevant contracts. The accounting treatment of abandonment-related expenses, including possible funds, would also need to be specified;

- *Insurance and indemnification* requirements and liabilities could be set out in a separate clause. The 2006 Model PSA does not impose minimum requirement for insurance. In line with industry practice and with generally accepted contract principles, balance and equity should be sought in defining the parties' liabilities and indemnities, especially in the case of sole risk operations carried out by YGC on behalf of the MOM;

- The cases in which the MOM can conduct *sole risk operations* in the contract area should be defined with a view to minimizing disincentives to the contractor's group. For example, the 2006 Model PSA provides for the MOM to have the option to conduct sole risk operations if the contractor fails to declare commerciality within the time frame indicated in the contract.[138] Given the relatively short time frame granted to the contractor to evaluate the discovery, this could be particularly challenging, especially when small accumulations are involved that could be economically exploited as part of a group of fields, and when the appraisals of such fields cannot be completed at the same time;[139]

- *Assignment* of rights and obligations is regulated under Article 20. The ability to transfer all or part of their rights and obligations in a contract area is very important in the petroleum industry where companies normally partner to decrease their risks. Generally, transfers to affiliated companies do not require particular formalities. Transfers to third parties are more complicated, as the host government needs to ensure that the assignee has the financial (and technical if the operatorship is transferred) ability to fulfill the requirement of the contract. Normally, the assignor is not required to guarantee the obligations of the assignee, especially when the assignee is not an affiliated company;[140] and

- *Assistance from the MOM and conflict of interest*. The privileges of the MOM's personnel are detailed in Article 16. The provision of assistance to the contractor by the MOM is mentioned in various parts of the 2006 Model PSA. To improve clarity and

[137] *Annex D, which details the terms of the irrevocable letter of credit in favor of the MOM, makes reference to the obligation of the contractor to clean up work sites (it is not clear from the wording whether this refers to reclamation, abandonment, or both). However, no financial guarantee appears to be attached to such obligation. Therefore, it is unclear how the letter of credit could provide coverage. In line with international good practice, the use of a performance bond or abandonment fund specifically related to abandonment operations could be considered.*

[138] *The maximum lead time for discovery to declaration of commerciality is defined as the shorter between nine months and 30 days after the completion of the relevant appraisal wells. A 24-month lead time is not uncommon in the industry: seasonal factors, unforeseen technical and engineering problems, among others, may affect the duration of appraisal. Especially when cost recovery limits exist, the contractor will have an incentive to accelerate the declaration of commerciality and start field development. In these cases, the government's concern that potentially commercial fields are not going to be expeditiously developed by the contractor may not be entirely warranted.*

[139] *Angola's model PSA is a good example of alternative wording.*

[140] *More standard wording can be found, for example, in the model PSA of Angola, Pakistan and Qatar. Industry standard wording for assignment of rights and obligations could also be considered.*

in line with good practice, the MOM's duties and responsibilities[141] and conflict of interest provisions[142] could be grouped under a specific Article and more clearly defined.

Although many elements of the fiscal package are negotiable, the Model MoU and the 2006 Model PSA provide the general structure of the fiscal policy and some boundary conditions for setting the level of the relevant parameters. These are summarized in Table 4.4.

The fiscal terms set forth in the Model MoU and in the Model PSA include some degree of flexibility, but this may not be sufficient to accommodate a variety of possible exploration and development conditions.[143] Production-based sliding scales provide a greater share of royalties and profit oil to governments at higher production rates. However, this type of arrangements is irresponsive to price and cost variations, and does not accurately correlate to the project's return on investment. In addition,

Table 4.4: Fiscal Parameters of the 2006 Model PSA and 2005 Model MoU[144]

Bonuses

Signature		$ _____	
Declaration of Commerciality	Oil	$ _____	Gas $ _____

Production	Oil		Gas	
	at Bopd	**$**	**at million scf/d**	**$**
	25,000	_____	250	_____
	50,000	_____	500	_____
	75,000	_____	750	_____
	100,000	_____	1,000	_____
	150,000	_____	1,500	_____

Royalty

Oil		Gas	
Bopd	**%**	**million scf/d**	**%**
0-25,000	3	0-250	3
25,000-50,000	5	250-500	5
50,000-75,000	6	500-750	6
75,000-100,000	8	750-1,000	8
> 100,000	10	> 1,000	10

Cost Recovery Limit

	% of Net Production_____	
Recoverable Costs	Operating Expenditure	100%
	Exploration Expenditure	50%
	Development Expenditure	50%

Nonrecoverable: Bonuses, training, interest fees and commissions on loans and guarantees

[141] *See the Model PSA of Angola and Qatar as examples.*

[142] *Conflict of interest provisions are generally set forth in a country's petroleum law. Because Yemen does not have a petroleum law, it would be advisable to clearly detail those situations that constitute conflict of interest as well as unlawful payments.*

[143] *The criteria to be used by the government in ranking and evaluating the 33 bidding elements contained in the Model MoU and the relative importance of the bidding parameters are not explicitly mentioned.*

[144] *It is worth noting that in the Model MoU that is being used to negotiate the terms of award of the blocks included in the 2006 licensing round, the sliding scales used in the determination of royalties and profit-sharing for gas have been amended to reflect a wider array of reservoir deliverability rates. See Chapter 5 for a discussion of the possible implications on contractor's and government's takes.*

Bonuses					
Excess Cost Oil			_____%		
Profit Oil Split					
	Oil			**Gas**	
Contractor	**Bopd**	**Ministry**	**Contractor**	**million scf/d**	**Ministry**
	0-25,000	_____		0-250	_____
	25,000-50,000	_____		250-500	_____
	50,000-75,000	_____		500-750	_____
	75,000-100,000	_____		750-1,000	_____
	> 100,000	_____		> 1,000	_____
Participating Interest			**Oil**		**Gas**
Carried through exploration and development For development of associated gas, the State participation is 60% (full carry)			%		%
Taxation					
	Paid in lieu by the Ministry on behalf of the contractor				
Ring Fencing	None				
Other					
Valuation of Crude Oil	Arm-length market price FOB point of export				
Assignment of Interest	15% capital gain tax if cash payment is involved				
Employee Personal Income Tax	3% of exploration expenditure for staff working on exploration activities 15% of actual salary for staff working on development related activities				

"excess cost oil" can be quite a difficult term to bid, especially when the potential investor is evaluating a new play[145] or when the contract area is located far from existing suitable infrastructure. The proposed structure of terms may have several consequences: the government may miss out on the potential upside of the project; the investors' expectations of real costs and prices may influence its production decisions; exploration and development thresholds[146] may increase. To deal with all these uncertainties, R-factor or return on investment-based scales could offer a much more flexible instrument as they are able to adjust more easily to a number of unknown circumstances thus providing for a more equitable[147] and stable[148] profit allocation arrangement. Since the performance of a fiscal system is affected by many variables (size and distribution of production in a given geological province,

[145] *The Model PSA, Annex C, Minimum Work Program and Expenditure, requires that three exploration wells be drilled and evaluated in the basement. Although a discovery was recently made, it may still be early days to judge the prospects for such an unconventional and challenging new play. In similar cases, various governments (for example, Australia, Canada, New Zealand and the United States) have adopted targeted incentives that have allowed them to influence the contractor's investment decisions by partially compensating for increased exploration and/or development risk.*

[146] *Prospects that might have otherwise been explored or fields that might have otherwise been developed may not get developed.*

[147] *That is, taxation would be based on the contractor's ability to pay.*

[148] *Because the fiscal burden changes in line with changes in project economics, the terms of the PSA would not need adjustment.*

technical parameters, economic variables, and so on, and so forth), modeling of alternatives would be necessary to ensure that the chosen system or systems will be flexible enough to respond to the most likely scenarios and will provide a result in line with the strategic objectives of the country's petroleum policy.[149]

Table 4.5 summarizes the recommendations outlined in this paragraph.

Other Countries' Terms

Assessing the impact of different legal and fiscal systems on investment decisions is not an easy task.[150] Each element taken in isolation does not provide an indication of the relative impact of a system. To gain a broader understanding of a system and of how it compares to other systems, it is necessary to analyze the system as a whole. In addition, many elements of contracts and concession agreements that do not get captured in the fiscal parameters affect the efficiency of operations and the investor's return on investment.[151] These are difficult to measure. Therefore, comparison of licensing terms in different countries or geological provinces is normally made with reference to the main fiscal variables. Table 4.6 summarizes the key elements of the petroleum fiscal systems for a selected number of countries.[152]

Table 4.5: 2006 Model PSA: Suggested Improvements

Topic	Recommendations
Contractor's Rights, Obligations and the Principles Underlying the Conduct of Operations	Clarity could be improved by gathering the topic under a common set of clauses
Right to Explore for and Produce Gas	Incentives could be designed to attract investors: These may include the following: • Longer duration of exploration and production periods • Lower minimum percent government carried interest in the development of associated gas • Longer evaluation period • Flexible fiscal terms
Health, Safety and Environment Protection	Environmental protection should be strengthened. In particular: • Environmental assessment, impact assessment and mitigation plan should be made a condition for approval of the relevant field development plans and for the grant of the relevant licenses and permits • The respect of international safety and labor standards should be specifically mandated

[149] *Although necessarily a simplification of reality, modeling will also be useful in defining the boundary conditions of the system for contract negotiation purposes.*

[150] *It is important to note that the effect of many nontax components of a legal and fiscal system is difficult to measure as it very much depends on the complexity of the project and on the ability of the investor to operate efficiently and effectively, in the particular environment. With regard to the tax components of a system, tax treaties can significantly affect an investor's fiscal obligations. Therefore, different investors may bear different tax burdens depending on their home country tax law as well as on their tax minimization strategies.*

[151] *For example: hiring requirements, unusual procurement limitations, permitting lead time, visa requirements, customs procedures, training and local procurement obligations, data access and management fees, crude oil and gas valuation rules, nonrecoverable project costs, and so on, and so foth.*

[152] *No ranking is intended or attempted.*

Topic	Recommendations
	• Sureties to cover potential environmental liabilities should be addressed in the Model PSA • The accounting and cost recovery treatment of environmental mitigation structures and equipment should be more clearly specified • The principles for land reclamation should be clearly defined
Land Use, Right of Access, Compensation and Resettlement	The principles and basis for compensation could be more clearly specified with particular reference to the difference between long-term and temporary land use.
Ownership of Data and Confidentiality	This should be brought in line with international standards and practice, with particular reference to the following: • The use by the contractor of information acquired during the term of the contract • The definition of what constitutes confidential information • The limitations imposed on disclosures to regulatory agencies, security commission, or stock exchanges In addition, provisions related to the Extractive Industry Transparency Initiative (EITI) could be included
Cost Control Procedures	The cost of supervision and the cost of compliance could be reduced and the efficiency of operations could be increased by introducing higher thresholds for approval of expenditures
Unitization	The right of the MOM to order unitization should be expressly provided for in the Model PSA
Abandonment	Abandonment procedures and related liabilities, and the accounting treatment of abandonment-related expenses, should be specifically addressed in the Model PSA
Insurance and Indemnification	Minimum requirements and liabilities could be set out in a separate clause
Sole Risk Operations	These should be defined with a view to minimizing disincentives to the contractor's group
Assignment	In line with international practice, the assignor should not be required to guarantee the obligations of the assignee, especially when the assignee is not an affiliated company
Assistance from the MOM and Conflict of Interest	To improve clarity and in line with good practice, the MOM's duties and responsibilities and conflict of interest provisions could be grouped under a specific Article and more clearly defined
Fiscal Terms	More flexibility could be introduced to accommodate different investment opportunities. The use of R-factor or return on investment-based scales could be considered

Table 4.6: Features of Petroleum Fiscal Regimes in Selected Countries

Country	*Royalties*	*Production-sharing*	*Income Tax Rate*	*Resource Rent Tax*	*Investment Incentives*	*State Equity*
Algeria	10-20%	50-85% (P)	None	None	None	51%
Angola	0%	50-90% (V)	50%	None	Yes (E)	20%
Benin	12.5%	55%	None	None	Yes (E,U)	15% (C)
Brunei	...	None	55%	None	Yes (A)	50%
Cambodia	5-12.5%	40-65% (V)	30%	None	Yes (E)	None
Cameroon	Negotiable	None	57.50%	None	Yes (O)	50% (C)
Chad	12.5-14.5%	None	40-65% (P)	None	Yes (E,I)	None
Congo B	15%	30-70% (V,P)	35%	None	Yes (O)	10-15%
Cote d'Ivoire	None	60-90% (V)	None	None	Yes (O)	10-12%
Dubai	12.5-20%	None	55-85%	None	None	None
Egypt, Arab Rep. of	None	70-87% (V)	40.55%	None	Yes (I)	None
Equatorial Guinea	10%	25-80% (P)	25%	None	Yes (E,H,I,O)	5-25%
Gabon	10%	65-85% (V)	None	None	Yes (E)	15% (C)
Indonesia (post 1988/89)	None	71.16%	48% (eff.)	None	Yes (A, I, Cr)	10%
Malaysia	10%	50-70%	None	40%	Yes(A, E, U)	15% (C)
Nigeria Offshore	4-8%	20-65%	50%	None	Yes (E,Cr)	None
Oman	None	80%	55%	None	None	None
PNG	2%	None	45%	20-25% (P)	Yes (I, Cr)	22.5% (C)
Qatar	None	55-70% (V, P)	None	None	None	None
South Africa	2-5%	None	30%	40%	Yes (O,U,I)	20% (C)
Thailand	5-15% (P)	None	50%	None	Yes (E)	None
Philippines	None	60%	32%	None	Yes (E)	None
Timor Gap – ZOCA	None	50-70% (V)	48% (eff.)	None	Yes (I, Cr)	None
Yemen	3-10%	70-80%	None	None	Yes (E, U)	None

Adapted from Baunsgaard (2001)
Sources: Barrows (1997) Coopers & Lybrand (1998), PricewaterhouseCoopers (1999), Otto et al (2000), Johnston (2003), Web Sites of country sector ministries.
Legends:
(1) Fiscal terms linked to volume of production (V), Years of production (T), Profitability indexes, R-Factor, ROR, Realized profitability (P).
(2) Investment incentives: Tax holiday (H), Accelerated depreciation (A), Tax credit (Cr), Current expenses of exploration and/or development costs (E), Exemption of imports of equipment and capital goods (I), Unlimited loss carry forward (U), and other (O).
(3) The maximum equity share that the government can opt for, if (C) on a carried basis.

Conclusions

Countries compete with each other to attract foreign investment to develop their natural resources. To achieve this, they must assess their position in the global marketplace and evaluate their particular situation, boundary conditions, concerns and objectives.

Although not all countries have made the same legal and regulatory choices, nearly all have established sector-specific legislation and regulation in line with their constitution and with the rest of the country's body of laws. One advantage of this approach is its transparency and its objectivity: by establishing the boundary conditions for the award of petroleum rights and defining the authority and procedures for such award, system inefficiencies and the scope for discretional behavior are greatly reduced.

Whether contractual or concessionary systems are used, the clarity and simplicity of the terms, the objectivity of the rules and of their enforcement, the neutrality, equity, efficiency and stability of the fiscal terms are among the key elements considered by potential investors in comparing investment opportunities.

To develop a fiscal system that is able to allocate risks equitably, policy makers need to take into account the divergent interests of companies and governments. Risks can be substantially different for different projects and countries and, over time, a fiscal regime that provides optimal outcomes under all circumstances is not likely to be developed. Although this may justify a case by case approach, this would hardly be efficient given the usually large number of projects and the limited administrative capacity of the host government. It is, therefore, desirable to build enough flexibility into a system to allow for automatic adjustments to unforeseen changes and to minimize the need and cost of negotiations and/or renegotiations.

Finally, it is important to note that good legal and fiscal design without complementary institutional structures may still not achieve the desired goals. The design needs to be within the administrative and audit capacity of the relevant institutions.

5. Encouraging the Development of Gas Reserves

Introduction

The energy market is evidently responding to the changing gas supply conditions, and exploration activity is expected to pick up. However, the speed and extent of that response in a particular country may be constrained by its specific circumstances. The identification of gas resources is not a sufficient condition to ensure a greater use of gas: transmission infrastructure and regulatory framework often need to be developed well in advance of anticipated demand.[153]

The development of a natural gas market is particularly important to GoY for its potential to support the creation and growth of the domestic industrial sector. In addition, revenue from gas exports may contribute to partially offset the decline in government revenue from currently producing oilfields.

This Chapter analyzes the potential barriers to the development of gas E&P activities, provides an overview of the policies that have been used in other countries to promote these activities and explores their applicability in Yemen.[154]

Given the high volatility of gas price compared to most commodities, possible risk mitigation measures aimed at preserving the year-to-year consistency in government revenues are outlined in the last part of this Chapter.

Barriers to the Development of Gas Exploration and Production Activities

Although oil and gas are often found in the same reservoir, they are significantly different. Unlike oil, natural gas: (a) cannot be inexpensively stored in large quantities; (b) sophisticated and expensive infrastructure is required to deliver it to the end users; (c) transportation costs, measured on the final price to the customer, can be 10 times higher than for oil; and (d) there is no world gas market,[155] hence no world standard price such as WTI, Brent or Dubai.[156]

As a consequence:

- The lead time to development of a gas field can be considerably long;[157]
- Investment in development and production of gas usually cannot go ahead without a

[153] *As outlined in Chapter 2, natural gas pricing is of critical importance in determining the size and shape of a country's internal gas market. When not left to the market, pricing should encourage: (a) gas consumption, by providing incentives for energy users to switch to gas; and (b) gas production, by giving investors a fair and reasonable return. In other words, gas pricing should ensure the viability of each link in the gas chain.*

[154] *The analysis assumes that the terms applicable to oil and gas exploration and development are those set forth in the 2006 Model PSA and the 2005 Model MoU provided by the authorities and presented in Chapter 4.*

[155] *Approximately, 85 percent of the gas consumed today in the world is produced locally.*

[156] *Prices in the U.S. market are linked to the HH price and adjusted for distance and quality of supply. Prices in Asia and Europe are normally a function of oil prices, and have been historically higher than U.S. gas prices (with short-term exceptions).*

[157] *World average lead time from exploration to development is approximately 10 years (D. Johnston, 2003).*

long-term commitment between producer and buyer;[158] and

- Small gas markets are difficult to develop, and small gas discoveries are normally hard to commercialize.[159]

In addition to the foregoing, the availability of skilled workers and specialized equipment, complex land access rights, the lack of infrastructure and the financial environment are commonly cited among the factors affecting gas exploration and development activities.

Table 5.1 identifies some of the factors that E&P companies are likely to consider in evaluating investment opportunities, the potential barriers to investment in Yemen and possible options to address these barriers.[160]

Table 5.1: Potentisal Barriers to Investment in Gas E&P in Yemen

E&P Investment Factors	Barriers to Investment	Possible Options
Prospectivity	• Access to quality and quantity of geotechnical and related information	• Audit existing reserves • Analyze available Geophysical and Geological (G&G) data, acquire new data/reprocess existing data, prepare gas prospectivity report and increase promotional activity • Favor/encourage data acquisition, processing, reprocessing and interpretation over wild cat drilling in evaluating bids/establishing work program obligations.
Exploration and Development Cost	• Relatively high costs of exploration and development may be due to geographic isolation, complex geological structures, lack of economies of scale (and limited competition between service providers)	• Facilitate multiparty work programs to improve economies of scale

[158] *In the gas industry, the developer of the reservoir and the end user of the gas are linked by a chain that connects the processing plant, the transportation network and the distribution network. Each link corresponds to a commercial relationship, and is dependent on every other link. Because the chain is vulnerable to disruptions, firm and long-term relationships are the norm "take-or-pay" and/or "ship-or-pay" clauses are generally used). Furthermore, risk management is a key element of project feasibility analysis. For an interesting analysis of the impact of short-term trading on risk management see "Some Risks Related to the Short Term Trading of Natural Gas," Ahmed El Hachemi Mazighi, September 2004, Organization of the Petroleum Exporting Countries (OPEC).*

[159] *Almost 50 percent of the total natural gas resource base (estimated at 6,100 TcF) is in "stranded" reserves, usually located too far away from pipeline infrastructure or population centers to make transportation of the natural gas economical (International Energy Outlook, Energy Information Administration (EIA), 2005).*

[160] *The feasibility of some of the options presented in Table 5.1, with particular focus on upstream fiscal terms for gas, is discussed later in this Chapter.*

E&P Investment Factors	Barriers to Investment	Possible Options
	• The 2006 Model PSA, Annex C, Minimum Work Program and Expenditure, requires that three exploration wells be drilled and evaluated in the basement	• Allow companies to choose the drilling location. If needed, offer targeted incentives to influence the contractor's investment decisions by partially compensating for increased exploration risk
	• Predominance of small and potentially resource constrained permit holders	• Provide targeted incentives to accelerate project payback • Grant investment uplift carried interest • Provide for zero royalty up to a certain value of production (gas-only) • Encourage multifield gas development projects
Size and Location of Gas Market[161]	• No significant local market • Potential demand located far from known reserves	• Form regional hubs for gas market development • Favor switching to gas through targeted incentives (tax credits, favorable depreciation rates, and so on, and so forth) • Establish pricing principles that correctly reflect the risk at every link of the gas chain
Availability of, and Access to Infrastructure	• Only one gas pipeline linking the Marib field to the LNG plant. The construction of a national gas pipeline is being evaluated	• Encourage private and foreign investment in gas pipelines • Establish regulations for Third Party Access (TPA)[162]
Legal and Regulatory Environment	• Both associated and nonassociated natural gas belongs to the State. The 2006 Model PSA establishes some general	• Give the contractor the right to develop a gas discovery if it deems it commercial. Key operational and fiscal principles to be laid out in the 2006

[161] *Measures to address this barrier were outlined in Chapter 3.*

[162] *The European Gas Directive, published in 1998, provides an example of TPA regulation. Its aim was to implement policies for a Europewide competitive market, where security of supply was and remains a key concern, through common rules for transmission, distribution, supply and storage The Directive requires the opening of transmission network and storage facilities to TPA. Countries may choose between either a system of "negotiated" TPA with the publication of the main commercial conditions, or a system of "regulated" TPA, based on published tariff structures. For a comprehensive analysis of the effect of TPA regulations on LNG facilities, see the proceedings of the 2005 LNG Issues workshop, http://www.energy.ca.gov/lng_docket/documents/index.html. It is important to underline that although the institutional structure should enable long-term competition between gas suppliers through open access to onshore pipelines and terminals, this kind of competition cannot be effectively introduced until the market is sufficiently well established. In an emerging gas market, reducing investors' risk is essential. In these cases, it may be appropriate to consider mechanisms that ensure competition while making use of economies of scale in the planning stage of a pipeline. One such mechanism could be to publicly announce the intention to build a pipeline and seek the participation of other players through a JV or by booking long-term capacity. If successfully implemented, this mechanism may leave only a small or no capacity left open for later TPA.*

E&P Investment Factors	Barriers to Investment	Possible Options
	principles, and provides for an additional agreement to be entered into between the contractor and the State if a commercial discovery of natural gas is made. The contractor is required to bid commercial terms for natural gas	Model PSA
	• No legal framework exists for processing, transporting and distributing gas	• Introduce specific regulations applicable to transportation, midstream and downstream operations • Define principles for pricing of natural gas sales[163]
Government Participation	• Government participation is carried through exploration and development. The percentage participation is a biddable term, but a minimum 60 percent State participation is mandated for the development of associated gas	• Government full-carried minimum mandatory participation in gas production may impair project economics: establish a *maximum* percentage *optional* participation • Carried participation limited to the exploration phase[164]
Fiscal Regime	• Royalties are calculated on the basis of a sliding scale based on the reaching of certain daily production levels. Different thresholds apply to oil and gas. Thresholds and rates are fixed	• Make royalties more respondent to the project economics, at least by using a sliding scale based on value of sales
	• Cost recovery limit is biddable. The recovery of exploration and development expenses is limited to 50 percent per annum starting on the date of initial commercial production or in the tax year in which the	• Increase the cost recovery limit for gas. Cost gas is normally higher than cost oil because of the higher incidence of costs over revenues in the initial phase of a gas project • Allow the deduction or partial deduction of interest on loans for gas projects

[163] *Tunisia's experience offers an example of how gas price policies can influence the level of E&P activities. In Tunisia, the gas price for local market sales is fixed by decree. Until the end of 1999, the gas price was indexed to 85 percent of the value of Mediterranean Heavy Sulfur Fuel Oil (HSFO) price. From 2000, the gas price has been indexed to 80 percent of the value of Mediterranean Light Sulfur Fuel Oil (LSFO). As a result, the price for sales of gas to the domestic market rose by approximately 18 percent. A study carried out by Wood Mackenzie to evaluate the impact of a number of incentives introduced by the 1999 hydrocarbon law, concluded that the change in the domestic market gas price policy was one of the key factors explaining the increased number of marginal fields that were subsequently developed. For more details see Taha Fezzani,* Tunisia: Impact of the 1999 Hydrocarbon Law, *MEES, volume XLVI, No. 2, January 13, 2003.*

[164] *It is quite rare for a host government to be carried through development.*

E&P Investment Factors	Barriers to Investment	Possible Options
	relevant expenditure is incurred. Interest, fees and commissions on loans and guarantees are excluded from cost recovery	
	• Production-sharing is net of taxes, which are paid by the State in lieu. Profit oil is shared between the contractor and the State on the basis of a sliding scale linked to daily production. Different scales apply to oil and gas. The thresholds are fixed but the percentage share is biddable	• Link production-sharing to index of project profitability
	• Bonuses are a biddable term. They are payable on signature, declaration of commerciality and at reaching various daily production targets for both oil and gas. The thresholds are fixed but the dollar amounts are biddable	• Production bonuses could be linked to reaching target levels of cumulative production as opposed to daily production
Other	• Several review committees and low thresholds for approval of expenditure	• Streamline approval procedures, and introduce higher-expenditure thresholds
	• The 2006 Model PSA requires the contractor to notify the MOM of a discovery of natural gas, and promptly meet to discuss whether an appraisal program is warranted. No maximum lead time from discovery to declaration of commerciality is established, but the contractor is given six months from the date of the first meeting between the State and the contractor with respect to the possible development of the gas discovery to finalize a gas project agreement/gas development agreement. This period can be extended by mutual agreement between the parties. The 2005 Model MoU indicates that the duration of the contractor's production rights is the same for oil and gas	• Define a reasonable lead time from discovery to start of negotiation of the gas project/development agreement • Extend the duration of the contractor's right to produce natural gas in line with other countries' practice

Some of the potential barriers identified above are short-term in nature, and/or can be addressed via initiatives that have a short term or temporary focus. Others will require regulatory interventions and carry long-term effects.

Options to Encourage Gas Exploration Activities

International Experience

- **Commonly Used Incentives**

Some of the most commonly used measures to encourage gas E&P include the following:

- *Royalty incentives*. Many producing countries have used their royalty regime to send signals to the market. In particular, targeted or blanket reductions in the royalty rates have been used to encourage gas exploration.[165] Changes in the level and structure of royalties: (a) can easily be targeted in the gas sector – therefore pose little risk of wider policy implication; (b) are quick to implement; and (c) can materially improve project economics. However, this type of incentive has limited impact on the contractor's upfront funding constraints, and rewards success only. Royalties based on volumes, daily or cumulative, impose burdens that vary inversely to changes in the gas price. This is not the case with ad valorem royalties that vary directly with the price for any given quantity level. Royalty incentives are often used to encourage the development of marginal fields. They may also help in extending the life of existing fields when gas prices fall. In order to limit the losses to the Treasury, royalty incentives are normally time-bound, or limited to a certain volume of produced gas, and/or a price level;

- *Drilling incentives*. These can take the form of tax credits for wells drilled at certain depths, or within a certain period of time, or for horizontal wells, or wells drilled in particularly high risk plays or unconventional gas (for example, coal seams and tight sands formations). Tax reliefs are normally capped to a certain volume of production,[166] and apply for a limited period of time. They may be suspended when gas prices rise beyond a level established in the tax regulation. This type of incentive aims at stimulating drilling activity in periods of low gas prices, and/or enabling the drilling of high-cost wells;

- *Accelerated depreciation*. This type of incentive allows for certain capital expenditure related to exploration and development of natural gas to be depreciated more rapidly for tax purposes. Accelerated depreciation delays *Government Take*. It is intended to accelerate the contractor's investment payback, and to encourage reinvestment;

- *Investment uplifts*. Uplifts allow the contractor to recover an additional percentage of capital

[165] *For example, New Zealand reduced its ad valorem royalty from 5 percent to 1 percent for discoveries made between June 30, 2004 and December 31, 2009; the Outer Shelf Shallow Water Deep Gas Royalty Relief Act, 2003, introduced royalty incentives for the production of shallow water deep gas in the Gulf of Mexico; for several years the states of Louisiana, Mississippi, Oklahoma and Texas offered tax incentives, including ad valorem tax relief/reduction, to encourage gas production from marginal wells, high-cost wells, coal seams gas and other unconventional production, and so on, and so forth – with mixed degrees of success. In Australia, all gas production, including LPG, LNG and commercial gas/ethane, and all condensate sold separately from oil, were exempted from the payment of excise under the Petroleum Excise (Prices) Act of 1987.*

[166] *For example, in 1977, the State of Louisiana launched an incentive program under which it offered 50 percent severance tax exemption on the first 2 MMCF/d of gas produced from the discovery well in new fields for a period of 24 months from the start of production. The program has been undergoing regular updates and amendments and it is still ongoing; the State of Texas offered 10 years full exemption commencing in September 1991 from payment of severance tax on high-cost gas produced from wells spudded between May 1989 and September 1996; in the same period and until January 2003, federal tax credit for gas produced from certain unconventional, high-cost formation was also offered – US$0.52/MMBTU for tight sands gas and US$0.8653/MMBTU for coal seams gas. Canada offered tax incentives for deep wells.*

costs through cost recovery.[167] This type of incentive aims to partially reduce the burden for projects that have a long payback time,[168] or are considered high-risk.[169] Sometimes an interest rate is applied to the host government-carried participation. Any interest rate greater than zero will increase the project NPV of the contractor, but the rate should not exceed the level at which a contractor would have an incentive to defer production;

- *Enhanced cost recovery limit.* In most cases, PSAs have a limit to the amount of revenue the contractor may claim for cost-recovery[170] but allow unrecovered costs to be carried forward to be recovered in succeeding years. Increasing the cost-recovery limit provides an incentive to the contractor to invest by accelerating project payback. In addition, in marginal fields, low-cost recovery limits can have a big impact.[171] Cost-recovery limits are often higher for natural gas than for oil.[172] When gas is produced in association with oil, in addition to the cost-recovery limit, what can be cost-recovered should be carefully defined;[173]

- *Tax loss carry forward.* The contractor's share of profit oil is usually subject to taxation. Usually, tax losses incurred in a given fiscal year can be carried forward to succeeding fiscal years. The carry-forward may be limited to a certain number of years or unlimited. Unlimited or long carry-forward periods are particularly important for gas projects that have a long lead time from exploration to production; and

- *Relaxation of ring fencing.* Usually, all costs associated with a given block or license must be recovered from revenues generated within that block – that is, the block is ring-fenced. However, some countries allow exploration costs to cross the fence.[174] The relaxation of ring fencing can provide a strong financial

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[167] *For example, an uplift of 15 percent on capital expenditures of US$100 million would allow the contractor to recover US$115 million.*

[168] *Typically, projects that have a long lead time from exploration to production.*

[169] *In Australia, under the Petroleum Resource Rent Tax Assessment Act of 1987, capital or operating costs directly relate to the petroleum project, and are deductible in the year they are incurred. Expenditures include exploration, development, operating and closing activities. Undeducted expenditures are compounded forward at a variety of set rates depending on the nature of those expenditures and the time that they are incurred prior to the granting of a production license. The legislation was substantially altered in 1990 to allow undeducted exploration expenditure incurred after that date to be transferred to other projects. Simultaneously, the carry-forward rate of undeducted general projects expenditures was significantly reduced from the long-term bond rate plus 15 percentage points to the long-term bond rate plus 5 percentage points. In 2004, the government introduced a 150 percent incentive to assist exploration in nominated frontier areas (the initiative ceases in 2008). The regime was found to have been reasonably effective in promoting exploration and development of oil and gas in marginal fields, and high-cost/high-risk areas.*

[170] *The cost-recovery limit is normally defined as a percentage of the revenue in a given fiscal year. The world average cost-recovery limit is 63 percent (D. Johnston, International Exploration Economics, Risk and Contract Analysis, Penn Well Corporation, 2003). In some frontier areas, the cost-recovery limit may range from 70 to 90 percent.*

[171] *According to Mr. D. Johnston, cost-recovery limits of 50 percent or lower can have the same impact on NPV and IRR as a 5-10 percentage point decrease in contractor take. See* Petroleum Fiscal Systems and Production Sharing, *PennWell Books, 1994.*

[172] *See some PSAs in Malaysia, Oman and Trinidad and Tobago.*

[173] *In Nigeria, different tax rate apply for oil and gas: oil projects are subject to 85 percent petroleum profit tax, while gas projects are subject to 30 percent corporate income tax. Until recently, it was possible to deduct all expenditure related to associated gas against the tax liability for oil. In some cases, investors had negotiated the right to consolidate the downstream plant consuming the gas as well. Even without the consolidation provision, the investors' post-tax economics were better than the underlying pretax returns for associated gas projects. For a detailed analysis, see Taxation and State Participation in Nigeria's Oil and Gas Sector, ESMAP, August 2004.*

[174] *In New Zealand, a 100 percent deduction is given for exploration expenditure in the year in which it is incurred, development expenditure is allowed as a deduction over seven years from the date of expenditure for offshore wells, and any losses arising are not ring-fenced either to permits, fields, or even the trade. That is, losses can be offset against any New Zealand income of the company or group of companies. When an exploratory well is converted to a production well, the expenditure that has previously been allowed on an incurred basis is clawed back, and then amortized over the next seven years. However, no adjustment is made to earlier years' tax assessments where the relief has already been allowed in full.*

incentive to the contractors, especially those who have existing production or are in a tax-paying position. The existence of a cost-recovery limit may enhance the importance of this type of incentive. However, the host government may end up subsidizing unsuccessful exploration. Some countries allow the consolidation of upstream, transportation and processing activities, and an array of different arrangements is used for LNG projects, which involve various degrees of consolidation.[175]

- **Lessons Learned**

Many countries have used some form of incentive to foster gas E&P activities whether in frontier acreage or in mature provinces. Their experience shows that the effectiveness of a specific form of incentive cannot be judged in isolation from the rest of the terms applicable to gas exploration and development activities, nor can it be delinked from the supply and demand conditions.[176] Some fiscal systems are more suited than the others to provide the flexibility that is needed to encourage investments that have a long lead time for implementation (hence are more likely to be exposed to changing economic conditions), and/or when a considerable level of uncertainty exists with respect to the prospectivity, and/or size and structure of the project. R-factor or rate of return-based production-sharing, royalties and/or profit taxes are example of flexible fiscal arrangements.[177] In addition, flexible fiscal systems limit the need for contract renegotiation. When incentives are provided, these should be targeted to specific policy outcomes. Incentives aimed at encouraging upstream gas exploration and development should take into consideration the whole gas supply chain so that they can be properly timed and the risk/reward can be properly allocated along the chain.

Assessment of Options to Encourage Gas Exploration in Yemen

In evaluating options to encourage more exploration activity, we have been focusing on those measures that respond to the following aims and design criteria:

- Materially improve the economics and/or reduce risk for gas exploration and/or production;
- Involve low compliance and administration costs;

[175] *Generally speaking, there are three models for organizing LNG projects: (a) an integrated structure in which the sponsors' participate both in the upstream development and in the LNG plant, and sales of LNG are made by the project; (b) the sale of feed-gas by the upstream owner to the LNG plant, which, in turn, sells LNG; and (c) a tolling arrangement in which the upstream owner retains title to the gas up to the point of sale, and pays a fee to the owners of the LNG plant for the liquefaction of the plant and its delivery (basically the LNG plant operates as a cost center). All these structures have been used in some form in designing LNG projects. The integrated structure avoids the definition of transfer price for feed gas. It is most suitable in cases where the feed comes from a single field, and all the sponsors have a share in the upstream field (although it is possible to use this structure for multifield projects). The Ras Gas project in Qatar is organized along these lines. The sale from upstream to the plant is probably the most frequently used solution, especially when there is a significant degree of common ownership. The Atlantic LNG is an example of this kind of arrangement. Tolling arrangements are rarely used. The LNG plants in Indonesia are organized along the lines of a tolling arrangement (see in particular the Bontang Plant): this type of structure has helped creating competition for feed gas among different fields. Although the company that owns trains 2 and 3 of the Atlantic LNG also owns the gas and sells it to buyers, the plant is paid a fixed fee, making this structure basically equivalent to a pure tolling structure. Given the large number of possible arrangements that may exist to accommodate the specifics of each project, sponsors' group, lenders and offtakers, it is not surprising that LNG projects have a long gestation time. Clearly, each structure affects the risk and economics of the project, as well as the benefits that the host government may expect to receive.*

[176] *The federal incentives for the production of unconventional and high-cost formations were offered in the United States during a period of oversupply in the market, when no increase in demand was expected. Because of this subsidy, unconventional gas could be sold for less than market value, thus displacing conventional gas that had to be shut in for lack of demand. Even some of the coal gas had to be shut in for lack of enough pipeline capacity to transport it. Some states, like Louisiana, where tight sands and coal seams were not present, were more affected than the others. See A.D. Koen, U.S. Tax Credits Spurring Coal Seam. Tight Sands Boom amid Controversy,* Oil and Gas Journal, *October 14, 1991, p.19.*

[177] *See Annex 3, Box A3.2.*

- Address market deficiencies;
- Minimize distortionary effects; and
- Are consistent with Yemen's macrofiscal policy, and with local development objectives.

These measures[178] can be grouped under three categories:

- Measures which are needed to enable gas exploration;
- Measures which economic impact cannot be practically quantified; and
- Measures which economic impact can be estimated.

- **Measures which are needed to enable gas exploration**

In drafting gas-related provisions in PSAs or concession agreements, policy makers are confronted with the reality that industry practice varies considerably, and that gas projects may exhibit an unusually high degree of contractual complexity.[179] For this reason, it is not unusual for contractual provisions to defer the setting of specific terms and conditions for the development and disposal of gas to special agreements to be negotiated between the parties in the event of a gas discovery. Nonetheless, some basic principles arising from accepted international gas industry practices are normally set forth in sector legislation and/or the relevant PSA or concession agreement. These may include: (i) the access to local gas market, domestic market obligations and pricing principles; (ii) the right to export a party's entitlement, and to market it to the highest value outlets; (iii) a sufficiently long minimum duration of the production rights; (iv) the terms of the host government's participation; (v) the right of access to infrastructure for purposes of processing and transporting gas at a competitive tariff; and (vi) the key principles of taxation and production-sharing.

In addition, the joint operating agreement among the coventurers may contain basic terms governing potential future sales of gas.[180] The disposition of gas deserves particular consideration, especially when small gas accumulations are involved. Given the lack of developed natural gas markets throughout the world, common stream disposition is the preferred approach for international gas ventures, where a single buyer under a long-term gas sales contract often solely supports the initial development of a gas field. Nonetheless, in some cases, separate marketing may need to be considered to avoid antitrust and trade practice concerns in some jurisdictions.[181] In some cases, if the government share of profit gas/royalty is paid in kind, this may have a large impact on project feasibility.[182]

In Yemen, the contractor does not currently have the right to explore for and produce gas, whether associated or nonassociated with oil, unless a

[178] *These were outlined in Table 5.1.*

[179] *It may be preferable for the contract to provide for a general and flexible framework for subsequent gas disposal arrangements, instead of addressing the specificity of all possible gas and infrastructure projects (for example, gas pipelines, LNG, gas-to-liquids, Compressed Natural Gas (CNG), and so on, and so forth).*

[180] *See AIPN Model Form 2005 for an example of joint and separate gas disposition provisions.*

[181] *For example, the European Union (EU), the United Kingdom and Australia.*

[182] *In February 2003, the government of India came under pressure to review its decision to take profit gas in kind as part of the New Exploration Licensing Policy Round V (NELP-V), following strong opposition from potential investors. Investors claimed that if the clause were to be implemented, it would be very difficult to predict what share of the gas the operator/producer would get from the field year, after year for marketing. Thus, it would be impossible to enter into long-term gas sales contracts. The government and the affected operators are still debating the subject.*

GDA, or a Gas Project Agreement (GPA) as the case may be, is entered into with the State. As a result, contractors do not actively explore for gas, and associated gas is reinjected – after stripping it from liquids if viable. Some government officials have suggested that discoveries of nonassociated gas may not even be reported by the contractor.[183] The 2006 Model PSA lays out some of the criteria that should inform the drafting of the GDA/GPA. In particular, if associated gas is to be developed, the 2006 Model PSA defines the time frame for finalization of the relevant GDA, and provides for a minimum percentage participation of the government – fully carried out by the contractor. Similar provisions apply for nonassociated gas.[184] The requirement to enter into negotiations every time gas is found in potentially economic quantities, may be justified by the government's need to ensure that fiscal and nonfiscal objectives are adequately taken into consideration.[185] At the same time, the prospect of potentially long negotiations and the uncertainty of their outcome are likely to discourage investors. One possible solution could be to grant gas E&P rights to investors under the relevant PSA and provide for flexible, progressive fiscal terms preferably R-factor or rate of return-based, so as to minimize distortions to investment decisions, and to adapt to the variety of potential project conditions. The key operational and fiscal principles would need to be laid out, including procedures for obtaining the necessary permits and licenses, evaluation of discoveries and declaration of commerciality, preparation, submission and approval of development plans, domestic market obligations and pricing principles. The accounting procedure annexed to the 2006 Model PSA would need to be amended to reflect rules applicable to associated and nonassociated gas. Service contracts and/or amendments to existing PSAs could be considered in respect to the development and production of known gas reserves.

Transportation,[186] processing and distribution of gas would need to be regulated, preferably by law. In the meantime, the government should make a clear, formal statement of its policy on natural gas, which should include the principles upon which the different aspects of the industry would be regulated, and which would set out the government's long-term strategy for development of the industry.[187] The gas policy, which should also be backed by a consensus of stakeholders, including current operators, potential industrial users and customer groups, should provide an initial level of comfort to investors.

Service contracts and/or amendments to the existing PSA could be considered in respect to the development and production of known gas reserves.

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[183] *If the contractor fails to finalize the GDA with the State within the six-month period set forth in the 2006 Model PSA, the State has the right to develop the field directly or in association with a third party. In this case, the contractor is obligated to relinquish the portion of acreage pertaining to a nonassociated gas discovery with no compensation – except for the possibility of cost-recovering exploration (and appraisal) expenses from cost oil (if applicable). Unless a GPA is entered into, a gas discovery and a dry well would be treated equally for the purpose of cost recovery. However, in case of a dry well, the contractor would not need to relinquish part of its acreage.*

[184] *Except that Article 27.4 specifically provides for the financial terms and conditions to be set out in the relevant GPA, which is to be entered into only after a commercial discovery. However, the financial terms for the production of both associated and nonassociated gas are among the parameters which the potential contractor is asked to bid on in the 2005 Model MoU. To avoid misunderstandings, it may be worth clarifying the wording of the relevant clauses in the 2006 Model PSA.*

[185] *It remains to be clarified why the 2005 Model MoU provides for the contractor to bid commerciality and production bonuses, and production-sharing for natural gas while the 2006 Model PSA does not grant the right to conduct such activities unless a GDA/GPA is entered into.*

[186] *Especially at the beginning of sector development, producers should be given the right to build and operate high-pressure pipelines – directly, through or in association with third parties – to transport their gas. The principles for TPA may be set in the relevant regulation and referred to in the 2006 Model PSA (footnote 163).*

[187] *See Chapter 3.*

- **Measures which economic impact cannot be practically quantified**

These include administrative measures aimed at promoting the attractiveness of Yemen's E&P to investors, and improving the efficiency of petroleum operations. In particular, the following were considered:

- *Improving the quality and quantity of geotechnical data.* Attracting new explorers, and/or encouraging the increase in exploration activities from existing contractors would require providing appropriate information on Yemen's prospectivity,[188] and on its investment environment. Efforts have already been made by PEPA, the MOM and the Ministry of Finance in preparing promotional material, including a web site containing information on doing business in Yemen. A geotechnical database was created, and is being filled with information provided by the contractors.[189] Some government officials have indicated that the lack of geophysical data in potentially prospective gas-prone areas has hindered the government's promotional efforts. Geotechnical data have historically been acquired from permit holders submitting data as part of the compliance requirements of the PSA. In defining work program obligations and evaluating bids, GoY could put the accent on data acquisition, processing, reprocessing and interpretation. In addition, the government could consider acquiring new seismic data, and/or reprocessing existing data, and interpreting data over specific areas ahead of a licensing round. Industry consultations could help government officials to confirm the location and the survey design and parameters. Seismic contractors could be contacted to explore their interest in carrying out a risk multiclient survey. Alternatively, funding could be provided under the State budget, and the investment could be partially recovered through data licensing fees.[190] The information derived from the interpretation of the data could be used to prepare promotional material, and could be presented at promotional conferences. The business case for investing in Yemen should be clearly made to ensure that existing explorers reinvest, and to attract new investors. Data packages could be prepared and provided to interested investors ahead of a licensing round. Deductibility of data licensing fees for cost-recovery purposes could be considered to provide further incentive to successful applicants;

- *Facilitating/coordinating multiparty work programs.* The function of leasing specialized equipment and employing technical contractors is the responsibility of the contractor who bears the associated risk. However, the MOM/PEPA receives detailed work programs providing a description of the type of activities that the contractors intends to carry out and the timing of these activities. This information could be used by

[188] *The gas reserves base in Yemen has been the object of speculation over the past years. At the end of 2005, gas reserves were estimated to be 16.9 Tcf, of which approximately 9 Tcf had been committed to the YLNG project. In 2007, the government launched a tender to assess the country's oil and gas reserves potential. PEPA also conducted an internal evaluation of the gas reserves potential in currently producing blocks (Annex 2).*

[189] *The functionalities of the data bank, and its working procedures, are not known at this stage, that is, integration and compatibility with generally used industry data management tools, access modalities, integration with modeling and interpretation tools. This paper assumes that the data bank is fully integrated with modeling and interpretation tools, and that it provides for online access to potential investors and existing contractors.*

[190] *Current average prices for onshore seismic acquisition and interpretation are approximately US$3,000/km for 2D and US$9,500/Square Kilometer (km²) for 3D. Equipment mobilization fee could be reduced by coordinating with the seismic activity of existing contractors.*

the authorities in a proactive manner. Coordination of drilling and seismic campaigns could be encouraged to reduce equipment mobilization costs. Operators could be allowed to share costs. Temporary importation procedures could also be optimized. Reducing costs, and improving the efficiency of operations, is particularly important for the contractors, especially in the current fiscal regime which is relatively insensitive to project profitability;[191]

- *Allowing and encouraging multifield gas development projects.* Whenever feasible, operators should be encouraged to jointly build or allow third party use of gathering, transport and processing facilities, so that economies of scale can be achieved and the benefit shared among the investor and the State. The development of multifield gas projects should also be strongly encouraged so that small gas accumulations may become economical and flexibility of supplies and competition among producers may be enhanced. Whenever technically feasible and economically desirable, the sale of gas from one block to another for use in operations could be encouraged with the objective of reducing operating costs;[192]

- *Streamlining approval procedures, and introducing higher expenditure thresholds.* As noted in Chapter 4, the 2006 Model PSA provides for various forms of oversight and cost control mechanisms, that is, management committees, procurement procedures, budget approval and audits. Expenditure thresholds appear to be particularly low compared to industry practice. This is likely to affect the efficiency of operations. Given the type of supervision and cost-recovery mechanisms currently provided for in the 2006 Model PSA, the government's cost of supervision and the contractor's cost of compliance could be reduced should greater freedom of operation be afforded to the contractor; and

- *Developing a local gas market.* The establishment of a legal, regulatory and fiscal framework that supports and encourages the development of a local gas market will provide assurance to upstream investors that even the development ofsmall gas accumulations may become commercially viable. Based on other countries' experience in developing their gas sector, investment in local infrastructure would need to be made well in advance of potential demand: timing and sequencing of investments is crucial. In the meantime, the government would need to reassure investors that gas findings would be allowed to find the highest value market. If domestic market obligations are imposed on the producers, they would need to be compensated at market price.[193]

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[191] *As mentioned earlier, production-sharing and royalties are determined the on the basis of daily production thresholds.*

[192] *The seller's cost recovery would be reduced by the value of the sale, while the buyer's cost recovery would increase by the same amount. Gas otherwise reinjected would be used in operations instead of crude oil or fuel thus reducing the operating cost/bbl for fields that do not produce gas in sufficient quantities to support their operational needs, at the same time, creating economies of scale for fields that produce more gas than needed for their own operations. Similarly, GoY could consider allowing interblock sales of gas for pressure maintenance – tax regulations or the PSA would be amended as appropriate.*

[193] *As illustrated in Chapter 1 of this report, there are essentially two approaches to gas pricing: the cost-plus approach, and the market-based netback approach. In the cost-plus approach, gas is priced independently from alternative fuels. This encourages gas production, but does not take into account its end use competitiveness. Furthermore, it does not encourage efficiency improvements. It could work in countries where gas resources are abundant and cheap to produce. The netback approach links gas prices more closely to competing fuels. For it to work, the price of competing fuels should be undistorted, and free negotiations between the players along the gas chain should be allowed. This approach would guarantee the competitiveness of gas against alternative fuels, and protect upstream and midstream investment. If this principle is applied, the rent – and the risk linked to price movements in competing fuels – is passed on to the producer, that is, the profits gained by the processing, distribution, transmission and storage services would not exceed the customary risk-adjusted profit on their investment and operation costs. However, the host government should devise a fiscal package that encourages the upstream operators to reinvest the extra rent. International experience demonstrates that netback pricing is the best approach to gas market development, especially when gas reserves are expensive and not abundant.*

- **Measures which economic impact can be estimated**

The fiscal regime could be used to convert the government's policy into economic signals to the market, and influence investment decisions.[194] Several countries have used favorable taxation of gas to support the development of the gas sector.[195]

Gas terms in any given country very much depend on the distance to market and/or on the ability of the domestic market to absorb the volumes that are being produced. For projects that are close to large markets, the fiscal terms for gas are rather similar to those applicable to oil.[196] When gas markets are distant, the *Government Take* is normally lower for gas than for oil.[197] This is done either by simply defining a lower *Government Take* for gas, or by using self-adjusting profit oil share, taxes and royalties.[198]

The fiscal parameters currently applicable in Yemen are detailed in Table 4.4.[199] The main features are summarized below for ease of reference:

- Royalty rates are determined on the basis of sliding scales based on reaching certain daily production levels. The rates at different thresholds of the sliding scale are the same for oil and for gas. However, the thresholds for gas are much higher than for oil;[200]
- Cost-recovery limits are the same for oil and for gas;[201]
- Profit oil split and bonuses are biddable. Similar to the royalty, these parameters are linked to a sliding scale by which thresholds are defined on the basis of daily production targets (fixed in the 2005 Model MoU). Different scales apply to oil and to gas; and
- Corporate taxes are paid in lieu by the MoM on behalf of the contractor.

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[194] *Provided that the framework is clear, is not changed retroactively and does not discriminate between the actors.*

[195] *However, tax policy should complement, not substitute, sector reforms.*

[196] *For example, see Alberta, Algeria, Argentina, the Netherlands, Norway, Pakistan, Thailand and the United States Gulf of Mexico.*

[197] *For example, see Australia, Equatorial Guinea, Indonesia, Nigeria, Malaysia, the North Western Territories in Canada, Oman, Trinidad and Tobago, Qatar, Republica Bolivariana de Venezuela, and other countries.*

[198] *The use of R-Factor or rate of return-based systems would automatically generate a lower* Government Take *if the profitability for gas is lower than the profitability for oil.*

[199] *It is worth noting that the most recent version of the Model MoU sets a minimum requirement in respect of all parameters – royalty rates, profit-sharing, cost-recovery limit and bonuses. Interested investors are required to match or better the minimum requirements.*

[200] *The use of a higher conversion factor results in lower royalties per Barrel of Oil Equivalent (BOE) for gas than for oil.*

[201] *It is worth noting that currently, the State has the right to request the contractor to deliver associated gas not used in operations at the point of separation. All costs associated with the production and the delivery of gas are paid by the State to the contractor. If the contractor and the State enter into a GDA for the development of associated gas, all cost related to such development – including the construction and operation of the relevant facilities – are cost-recovered from the annual gas revenue, and the State has a minimum 60 percent fully carried participation. The PSA does not specify how joint costs are allocated between oil and gas, however, the accounting procedure makes reference to generally accepted accounting principles. If no GDA/GPA is entered into between the State and the contractor, exploration and appraisal costs may be recovered from cost oil (if applicable) according to the cost recovery procedure set forth in the PSA. Associated and nonassociated gas are treated in a similar way, except that if nonassociated gas is discovered and a GPA is entered into between the State and the contractor, Article 27.3 paragraph 2 would appear to grant the contractor the right to recover all exploration and appraisal costs incurred by it as exploration expenditure from cost oil (or from the annual gas revenue if no oil production exists) without applying the cost recovery limitations set forth in Article 7. If this interpretation is correct, it may reflect an attempt to compensate the contractor for the extra risk taken when nonassociated gas is discovered, although the mitigating effect would only apply if oil is produced in the same contract area and if agreement is reached for its development under a GPA.*

Quantifying the impact on exploration activities of the measures cited in Table 5.1, and determining the optimal package in terms of scale and value, is a very difficult exercise for a number of reasons: (a) the effect of some measures can only be assessed in the medium term; (b) some measures may provide incentives for activities that might have occurred anyway; (c) the effect of fiscal measures on existing players and on new entrants is different; and (d) the estimate of the overall macroeconomic effect is heavily affected by a number of factors, including the timing and nature of future discoveries. Insufficient knowledge of the country's prospectivity makes it hard to anticipate how many viable gas prospects could be drilled over any given period of time.[202] Modeling of alternative options is further complicated by the fact that the average finding and development costs, and the lifting costs are not publicly available, although industry sources had suggested that these might be higher than the regional average.[203] Furthermore, the value of currently unrecovered exploration and development expenses is not known to the authors, hence it was not possible to determine the effect on government revenue should the recoverability rate be increased, and its application extended to expenses incurred by the contractors in the past. Nevertheless, and keeping in mind the limitations expressed above, a simplified[204] economic model of a hypothetical petroleum project was developed for the sole purpose of illustrating the effect on project economics of alternative fiscal terms and their relative responsiveness to changes in economic conditions.[205] The key parameters utilized are listed in Table 5.2.

[202] *In designing fiscal systems, the probability of success, the expected average size of future discoveries and the average finding and lifting costs are key data.*

[203] *The average finding costs, defined as the costs of adding proven reserves of oil and natural gas through exploration and development activities and the purchase of properties that might contain reserves, were estimated to be US$9.18/BOE worldwide, and US$6.76/BOE in the Middle East. The estimated average pretax lifting costs for the same period was US$4.23/BOE worldwide, and US$4.36/BOE in the Middle East (Performance Profile of Major Energy Producers, EIA, 2004). See also OMV starts oil production in Yemen, press statement released on December 27, 2006.*

[204] *In modeling the field economics under different contractual and fiscal systems, simplifying assumptions were made. In particular: no distinction was made between intangible and tangible costs; investment credits – normally cost-recoverable – were not considered; a deterministic approach was used to calculate production, costs and prices; abandonment provisions were not included. Where the participation of the national oil company was considered, its share of expenses was carried by the contractors' group without applying any interest rate. Only two fields were modeled (respectively associated and nonassociated gas). Statistical or stochastic methods could be applied to determine the possible value distribution of the project variables in Yemen. Due to the lack of relevant data, this approach was not attempted in this report.*

[205] *To stress test alternative fiscal policies, GoY would need to carry out a similar type of analysis using system parameters that are representative of the universe of oil and E&P projects in Yemen.*

Table 5.2: Key Parameters – Economic Model of a Hypothetical Petroleum Project

	Oil and Associated Gas	Nonassociated Gas
Recoverable Reserves[206]	95.6 MBOE	1.1 Tcf
Peak Production Rate[207]	17.9K BOE/d	223 MMCF/d
Gas-to-Oil Ratio (GOR)	3,510[208]	NA
Field Life	23 years	23 years
Price	US$30/bbl and US$4.5/MMCF	US$4.5/MMCF
Total Capital Costs (Capex)	US$554 million	US$1,004 million
Full Cycle Operating Costs (Opex)	US$3.71/BOE (US$5.31/bbl and US$0.20/MMCF)	US$0.25/MMCF

Note: NA = Not available.

Four alternative methods to calculate the government share of profit – oil/gas were modeled: daily production – Fiscal Model 1,[209] cumulative production – Fiscal Model 2, R-Factor[210] – Fiscal Model 3, and rate of return[211] – Fiscal Model 4.[212] Thresholds and trigger rates for R-Factor and rate of return-based profit split were the same for oil, associated gas and nonassociated gas. The trigger rates for profit oil split used in daily production and cumulative production-based models were the same, while thresholds for daily production profit oil split were based on the 2005 Model MoU, and for cumulative production profit oil split were consistent with those established for gas on an energy parity basis. A different cost-recovery limit was applied to oil (40 percent), associated gas (50 percent) and nonassociated gas

[206] *Technical parameters (field size, probability of success, location, and so on, and so forth) were estimated on the basis of the data contained in World Petroleum Assessment 2000, Assessment Unit 20040101, prepared by the U.S. Geological Survey. An abstract is shown in Annex 3.*

[207] *When simulating the impact of variations in production levels, the same percentage was applied throughout the production horizon (no adjustment to the production rate to take into account facilities specifications and/or reservoir, management needs).*

[208] *The U.S. Geological Survey estimates that GOR values could vary between 2,000 and 6,000 in the Ma'rib-Al Jawf/Shabwah/Masila basin, and between 1,000 and 3,000 in the Red Sea Salt basin. See World Petroleum Assessment 2000, USGS, Assessment Units 20,040,101, and 20,710,202. Average GOR for existing fields appears to vary between 3,500 and 4,200 (see Oil and Gas Directory at www.oilandgasdirectory.com/ogd/res_prod/Yemen.pdf).*

[209] *The thresholds and triggers set forth in the Model MoU were used.*

[210] *The R-Factor was calculated as the ratio between after-tax revenues and total project costs (capital expenditure and operating costs). Different countries use different definitions of R-Factor. Therefore, it may not be difficult to compare fiscal parameters among countries/contracts as their effect on project economics can be quite different.*

[211] *In rate of return-based systems, net annual cash flows are compounded at the target rate of return rate and carried forward until the cumulative amount becomes positive. When the investor has recovered the initial investment plus the target rate, the tax kicks in. Theoretically, the target rate of return should represent the minimum rate to encourage investment.*

[212] *To simplify the analysis, we chose to keep the same basic structure of the currently applicable fiscal regime (2005 Model MoU). Therefore, all fiscal models are the same, except for the calculation of profit-sharing between the government and the contractor. It is important to underline that, given the unavailability of the key technical and economic data applicable to oil and gas exploration and development in Yemen, the alternative fiscal models analyzed in this Chapter 5 were not designed to optimize the fiscal system in Yemen, but merely to show how different fiscal systems respond to changes in economic and project conditions.*

(70 percent). The relative performance of these fiscal models was assessed by allowing a selected number of system parameters to change.[213] The results (measured in terms of break-even price,[214] the NPV of the project's cash flow,[215] IRR,[216] Profitability Ratio (PR),[217] Net Present Value Per Barrel of Oil Equivalent (NPV/BOE),[218] operating leverage,[219] percentage *Government Take*,[220] and Saving Index (SI)[221]) are summarized in Table 5.3. Detailed calculations are shown in Annex 5, Table A 5.1, Table A 5.2, Table A 5.3 and Table A 5.4.

Our simplified analysis illustrates that the anticipated size and distribution of production in a given geological province is a key element for the design of a fiscal system. For all fiscal models analyzed in Chapter 4, variations in the level of production considerably impacted project economics (plus or minus 40 to 65 percent of base case NPV for production-based models, plus or minus 30 to 55 percent for R-Factor models, and plus or minus 30 to 50 percent for rate of return-based models). Similar results were obtained for price variations. A variation in the level of production or of prices resulted in large percentage variations of the project's NPV because of the rigidity of capital investment. The higher the project's operating leverage, the larger the impact of a variation in price or production level. In our models, a variation in the level of

[213] *To simplify the interpretation of the results only, one parameter at a time was allowed to change. A stress test was also carried out for all fiscal models by calculating the project's NPV at different discount rates resulting from decreasing the production level and price by 20 percent and increasing Capex and Opex by 20 percent. In reality, the likelihood, magnitude and timing of changes in technical and economic parameters have different effects on project economics, and on the overall performance of the system.*

[214] *The minimum level of gas price that causes the project's NPV to become zero.*

[215] *It is worth noting that each government and each company has a unique risk-reward profile, and, hence, uses a specific discount rate. The choice of what discount factor to use is an important decision for companies evaluating projects since selecting a high rate may result in "missing" good investment opportunities, while selecting a low rate may expose the firm to unprofitable or risky investments. Host governments value money in the same way as companies do. However, their expected benefits should be discounted using the social discount rate, that is, a rate that reflects society's preferences for allocating the use of resources over time. A higher rate will attribute more weight to benefits to the current generation than to future generations. The calculation of the parameters that are necessary to determine the social discount rate involves a certain degree of value judgment. In addition, countries may have considerably different social discount rates. This, of course, provides the scope for negotiating contract and fiscal terms.*

[216] *The IRR measures the relative attractiveness of a project. In general terms, project that present higher IRR should be preferred. Due to its limitations, the IRR is normally used in conjunction with other profitability indices. For an in-depth discussion of the IRR and of other commonly used financial measures of profitability, see Brealey, R.A. and S.C. Myers. 1991.* Principles of Corporate Finance. *McGraw-Hill, New York, NY.*

[217] *The Profitability Ratio (PR) is used by companies to compare projects around the world. The PR is calculated as the ratio between the NPV of the sum of the project's cash flow and total capital invested in the project to the NPV of the total capital invested in the project. It measures the profitability per dollar invested.*

[218] *This indicator allows companies to compare investments around the world, irrespectively of the size of the project.*

[219] *The operating leverage was calculated as the ratio of the NPV of the total cost to the NPV of gross revenue. Both flows were discounted at 10 percent. The higher the operating leverage, the more exposed the project profitability is likely to be to a fall in prices. Project with high operating leverages, all other project variable being equal, are relatively more exposed to the risk of losses under regressive fiscal regimes. See G. L. Kretzschmar, P. Moles, The Impact of Tax Shocks and Oil Price Volatility on Risk: A Study of North Sea Oilfield Projects, April 2006, W.P. 06.01, University of Edinburgh.*

[220] *The* Government Take *(defined as the percentage of government's net cash flow on total available cash flow), and the* State Take *(defined as the percentage of government's and NOC's cash flow to total available cash flow), were calculated on an undiscounted and on a discounted basis. To simplify the comparison with the contractor's take, all cash flows were discounted at 10 percent. In reality, the government's cash flow should be discounted at the social rate (footnote 179). This is likely to be lower than 10 percent, thus increasing the percentage* Government Take. *It is worth noting that most* Government Take *statistics are calculated on an undiscounted basis. This needs to be taken into consideration in comparing the average* Government Take *in different countries.*

[221] *In designing fiscal systems, it is important to create an alignment between the contractors' interest and the host government's interest. In this context, creating incentives for cost-savings is an important objective. The Saving Index (SI) is defined as the part of an additional one dollar in profit (arising from a one dollar saving in cost) that accrues to the contractor. It measures the degree to which the contractor will benefit from a reduction in costs (D. Johnston, International Exploration Economics,* Risk and Contract Analysis, *PennWell 2003). In general terms, the contractor would always have an incentive to save (especially during the exploration phase). However, fiscal systems that have a very low contractor's marginal take are more likely to create a lower incentive to saving.*

Table 5.3: Fiscal System Indices

	Oil			
	Fiscal Model 1	**Fiscal Model 2**	**Fiscal Model 3**	**Fiscal Model 4**
Contractor's Cash Flow (NPV10%)	119.7	116.5	121.3	128.4
Break-even Price	20.43	20.56	18.70	18.45
Project's IRR	18.4%	18.3%	20.1%	20.3%
NPV (10%)/BOE	2.03	1.98	2.06	2.18
PR (10%)	0.47	0.45	0.47	0.50
Operating Leverage (%)	55.0%	55.0%	55.0%	55.0%
Government Take (%)	47.5%	48.9%	46.8%	43.7%
Saving Index (US$)	0.70	0.67	0.59	0.64
	Associated Gas			
	Fiscal Model 1	**Fiscal Model 2**	**Fiscal Model 3**	**Fiscal Model 4**
Contractor's Cash Flow (NPV10%)	78.7	78.7	81.0	82.4
Break-even Price	3.21	3.21	3.03	3.00
Project's IRR	18.5%	18.5%	19.6%	19.7%
NPV (10%)/BOE	2.15	2.15	2.21	2.25
PR (10%)	(0.22)	0.39	0.41	0.41
Operating Leverage (%)	60.9%	60.9%	60.9%	60.9%
Government Take (%)	42.1%	42.1%	40.4%	39.4%
Saving Index (US$)	0.82	0.75	0.68	0.70
	Nonassociated Gas			
	Fiscal Model 1	**Fiscal Model 2**	**Fiscal Model 3**	**Fiscal Model 4**
Contractor's Cash Flow (NPV10%)	558.2	346.3	428.2	471.1
Break-even Price	2.35	2.53	2.31	2.28
Project's IRR	22.7%	21.2%	21.6%	22.0%
NPV (10%)/BOE	2.88	2.28	2.21	2.43
PR (10%)	0.60	0.66	0.64	0.70
Operating Leverage (%)	45.5%	45.5%	45.5%	45.5%
Government Take (%)	52.5%	48.2%	49.8%	44.7%
Saving Index (US$)	0.61	0.62	0.55	0.62

production had the lowest effect on the project's NPV for nonassociated gas (51.8 percent operating leverage), while associated gas (60.9 percent operating leverage) was affected the most. This is a very important consideration in the design of a fiscal system as market prices and geological conditions can be estimated only with a high degree of uncertainty. Therefore, companies undertaking capital-intensive and complex projects, or risk-adverse or smaller companies' would logically prefer fiscal systems that provide a cushion in case of adverse conditions. When project financing is involved, a fiscal system that is less sensitive to changes in project economics will increase the perception of risk, and ultimately the average cost of capital and the exploration and development thresholds.

Since capital expenditure mainly occurs in the initial phase of a project, variations in its level have a large impact on project economics,[222] especially when a cost-recovery limit is imposed[223] and/or the State's participating interest is on concessional terms.

Figure A5.1 and A5.2, A5.3 and A5.5 in Annex 5 show the effect on project profitability of different levels of cost recovery limit for the four fiscal systems modeled in this Chapter.

The choice of trigger rates or thresholds is a key issue for all fiscal models. It is quite unlikely that a particular set of triggers or thresholds would be able to optimize the *Government Take* under all possible scenarios. For example, if the thresholds for triggering higher profit oil/gas splits are too wide, the system may not efficiently capture the economic upside of a project. This can be seen in Fiscal Model 1: the daily production thresholds necessary to trigger a higher profit oil/gas split in favor of the government were never reached, and the percentage profit oil/gas split remained the same for the entire life of the fields modeled in our example.[224] There were no significant differences between R-Factor and rate of return-based profit split respectively in the first 10 years of production for nonassociated gas, and in the first 14 years of production for associated gas and oil. This was due to the fact that the first three thresholds of the R-Factor-based model closely matched the variation in the project's IRR.

Like Yemen, the majority of existing PSAs uses sliding scales based on cumulative production

[222] *In Yemen, an exploration tax, calculated as 3 percent of exploration Capex, applies. It is meant to substitute personal income taxes for the personnel of the contractor carrying out activities contemplated in the relevant PSA. The exploration tax emphasizes the effect of an increase in Capex. In other words, the tax increases the operating leverage of a project.*

[223] *In general terms, higher cost-recovery limits allow the contractor to achieve payback of its investment faster. However, when sliding scales are used to determine the percentage of profit oil (or the tax rate), in some cases, higher cost recovery limits may lower the contractor's full cycle discounted cash flow. This would depend on several factors including the discount rate, the level of saturation of the system, the operating leverage, and the steepness of the sliding scale vis-à-vis the changes in the project's IRR.*

[224] *Under the terms of the most recent Model MoU applicable to PSAs to be negotiated for blocks awarded under the 2006 licensing round, the thresholds for gas production have been significantly changed compared to the terms set forth in the 2006 Model MoU. Under the new terms, royalties and production-sharing would be calculated on the basis of the following sliding scale:*

% Royalty		**% Profit Gas Split**		
Million scf/d		*Million scf/d*		
			Ministry	**Contractor**
0-25	_____	*0-25*	_____	_____
25-50	_____	*25-50*	_____	_____
50-75	_____	*50-75*	_____	_____
75-125	_____	*75-125*	_____	_____
>125	_____	*125-250*	_____	_____
		>250	_____	_____

Depending on the triggers set by the MOM as minimum requirement – which may be different for different basins – the use of much lower thresholds is likely to increase the Government Take. *On the other hand, the new terms should improve the flexibility of the fiscal regime compared to the terms applicable under the 2005 Model MoU. However, as earlier, fiscal systems that use daily production thresholds are less sensitive to changes in project economics than systems that use cumulative production, R-Factor, or rate of return-based thresholds.*

levels, or daily production levels. In some cases, different thresholds and trigger rates apply depending on the water depth, or the well depth, and so on, and so forth. In some PSAs the production-based profit oil/gas split is further linked to the level of oil prices and/or the R-Factor.[225] Sliding scale terms introduce flexibility in fiscal systems. This theoretically allows small and large fields to be developed on equitable terms. In reality, the neutrality of the system largely depends on how the thresholds are defined, and how closely they relate to the profitability of the underlying project.

Figures A5.1, A5.3 and A5.5 in Annex 5 show the sensitivity of *Government Take* and project profitability to changes in prices for the fiscal systems modeled in this paper. The *Government Take* is very regressive when the profit oil/gas is shared on the basis of daily or cumulative production levels. In general terms, profit oil/gas splits based on production levels are less neutral to investment decisions than R-Factor and rate of return-based splits, as the percentage split remains the same even if important changes in project economics should occur.[226] On the other hand, these systems are easier to administer and may prove reasonably efficient in sharing the rent between the contractor and the government when project uncertainty is low, especially if used in conjunction with price indices.

R-factor and the rate of return-based models have a lower break-even price (Table 5.4), which makes them more attractive to the contractors and less risky candidates for project financing.

The impact on project economics of the government's participation through the NOC deserves special consideration. As highlighted in Chapter 4, if concessional conditions apply to the government back-in interest – that is, if the government does not pay its way in, or pays it only partially – this would have implications on the contractor's NPV. Furthermore, because, under a PSA, the contractor is allowed to recover expenses (its share and the carried) with a limited or unlimited carry-forward, this may result in an implied borrowing rate for the host government that is higher than its marginal borrowing rate. In addition, unrecovered expenses affect the calculation of R-Factor and rate of return, which, in turn, may affect the level of *Government Take* when profit oil split is determined on the basis of target R-Factor or rate of return levels. Therefore, when a carried interest is involved, the decision to exercise the back-in option, and the consequent use of public resources, needs to be evaluated in light of the overall macroeconomic objectives and resource allocation priorities of

Table 5.4: Break-even Price

	Fiscal Model 1	Fiscal Model 2	Fiscal Model 3	Fiscal Model 4
Oil	20.43	20.56	18.70	18.45
Associated Gas	3.21	3.21	3.03	3.00
Nonassociated	2.35	2.53	2.31	2.28

[225] *Approximately, 25 percent of PSA around the world use R-Factor or rate of return-based systems.*

[226] *Mathematically, it is always possible to design thresholds and triggers of a sliding scale based on production levels that match the changes in project economics. Since this can only be done at the end of the life of any given project and is bound to be different for each project, the use of rate of return and R-Factor triggers is likely to be more efficient at sharing the project's upsides and downsides between the contractor and the host government.*

the government. Annex 5, Table A 5.4 shows the effect on project profitability of a 30 percent participation of the NOC carried through exploration and development.[227]

Due to the high level of uncertainty that characterizes gas E&P, the government is unlikely to succeed in the design of a fiscal system that suits all projects under all possible circumstances (both endogenous and exogenous). In this case, the best approach would be to allow a certain degree of flexibility in the key fiscal parameters so that the system can adapt itself to changes in circumstances, by automatically capturing a reasonable amount of benefits when project economics improve and lowering the *Government Take* when project economics worsen.

The examples shown in this Chapter illustrate that, in order to capture a suitable share of profit oil, the government needs to make reasonable assumptions on the size and profile of a typical project, as well as to determine the typical variability in key project parameters. This would allow it to determine a representative distribution of R-factors, or rates of return, or other parameters chosen as thresholds, and to set appropriate floors and ceilings for such thresholds. Sliding scale profit oil/gas split, especially if linked to the return on investment, lower the project-specific risk by introducing flexibility in the fiscal package to suit the actual profitability of the particular project. Because of their flexibility, these types of arrangement are more likely to encourage the development of marginal fields, and of complex projects with a long lead time for implementation.

Depending on its overall fiscal policy needs, the government may seek different levels of front-loading at different point of time. In order to achieve its objectives while maintaining a reasonable level of investment incentives, the government would need to seek a trade off between regressive features (royalties, cost-recovery limits, exploration tax) and progressive features (rate of return, R-Factor-based taxes or production-sharing). Although progressive regimes are most successful in optimizing the *Government Take* under varying economic conditions, they may enhance revenue volatility. Various risk management tools exist to smooth revenue volatility, the costs and benefits of which need to be carefully considered. These tools are outlined in the subsequent paragraphs.

Even when a flexible fiscal regime is established for gas exploration and development activities, the government would still need to regularly assess its performance, and to adjust the relevant parameters as needed so that the fiscal regime applicable to future projects reflects changes in market conditions, government policy and geological and country risks.[228] In addition, complex or integrated gas development project

[227] *The NOC participation was modeled with respect to the 1Tcf nonassociated gas project. The percentage participation would have to be halved in the case of nonassociated gas for the project IRR to remain above 15 percent. It is important to note that the IRR is one of the parameters used by oil companies to rank their investment opportunities. Companies set a target rate(s) that reflects the project risk and the investor's corporate profile. All other things being equal, investment opportunities with an IRR below the target rate are not likely to be considered. Although target rates are unique to each company, a 15 percent target rate would not be uncommon.*

[228] *An interesting example of comparative analysis of the competitiveness of Alaska compared to six other long-distance exporting countries was recently carried out by Pedro van Meurs. The study aimed at determining whether the proposed Alaska Gas Pipeline would be competitive under the applicable tax regime, or whether the incentives proposed under the Stranded Gas legislation would be necessary. The study found that the project would be competitive with other long-distance exporters to the lower 48 market only if the PPT was coupled with the incentive proposed in the Stranded Gas legislation. Among the seven jurisdictions analyzed in the study, Oman exhibited the most regressive fiscal regime, while Australia's fiscal regime was very progressive at high price levels. If the terms applicable in Australia were applied to the proposed Alaska Gas Pipeline project at US$4.5/MMCF, the* Government Take *would have been 56 percent. The lowest* Government Take, *39 percent, would be obtained by applying the terms applicable in Oman. See Pedro van Meurs, Gas International Comparison, Appendix S, December 2006, http://www.revenue.state.ak.us/gasline/ Gas International Comparison.*

may warrant the negotiation of special arrangements which may include upstream and midstream activities.[229]

Gas Price Volatility and Risk Mitigation

World trade in natural gas is divided among major regional markets dominated by pipeline infrastructures that provide the means of transporting the gas from producers to customers and a single worldwide market for LNG. The United States is the largest pipeline gas market.

Natural gas is among the most price-volatile commodities. Natural gas is particularly subject to wide price swings as demand responds to changing weather conditions. Inventories are of limited help in damping price spikes.[230] The infrastructure that is needed to deliver the gas to end users is expensive. Gas transportation costs are several orders of magnitude higher than oil transportation costs. Furthermore, the transportation system is relatively inflexible: shipping low-cost supplies to areas where prices are high can be very difficult because of limited capability on the physical networks connecting customers to suppliers.[231] The foregoing factors can cause prices to soar in areas where demand increases suddenly. In addition, the deregulation process that has been undergoing in many countries with developed gas markets, has encouraged the growth of spot markets,[232] thus increasing price volatility.

For gas exporters, one significant impact of the changing environment has been the development of a short-term LNG market. Although long-term LNG contracts are not likely to disappear, importers are seeking increased flexibility and better contract terms.[233] Box 5.1 summarizes the key differences in price structure for the main LNG markets.

Gas price volatility affects all market participants: producers, gatherers, processors, transporters, storage operators, users and governments. There are several steps that market participants and regulators can take to mitigate price volatility. These include: contracting for firm transportation and storage; switching to lower-cost alternate fuels; using financial hedges to create price certainty; contracting under long-term fixed price agreements; and making available timely and reliable information regarding supply, demand, and storage levels. As market participants are exposed to different types of risk, and exhibit different levels of risk tolerance, their approach to risk management and their mitigation strategies is likely to be considerably different.

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[229] *See footnote 176.*

[230] *Although natural gas storage offers an effective way to hedge volume risk and fix a price, storage has significant costs and risks associated with it. In addition, operability factors are important. For conventional oil and gas storage reservoirs, deliverability is dependent on the amount of gas in storage. The greater the amount of gas in storage, the greater the pressure of the reservoir and the greater the deliverability. This has implications in terms of the time needed to reach the necessary pressure, and the withdrawal rate. Salt domes do not have the same limitations: by allowing more flexible withdrawals rate they can provide more effective protection against price volatility. However, the bulk of existing storage capacity is made up of conventional reservoirs. According to a study carried out by Mercer Management Consultant in June 2006, the price of storage facilities has increased considerably in the United States, and several new multicycle storage projects are being proposed by LDC, pipeline operators and gas producers.*

[231] *Location arbitrage does not work as well for gas as it does for oil. Since gas is essentially a network industry, customers cannot buy gas "off the system." In addition, arbitrary price differences in transmission charges – that is, not based on marginal cost – between and across markets are not infrequent. In a competitive market, the price differences due to transportation should be eliminated by arbitrage. This is not the case for natural gas.*

[232] *Traditionally, natural gas contracts were long-term contracts between integrated natural gas companies and users, with fixed prices, reduced supply and price risks and little flexibility. The importance of these contracts has been reduced as a result of the liberalization of the industry. Spot markets have emerged generally in areas with concentration of buyers and sellers as pipeline interconnections located close to large-consuming regions, or major terminals of gas-producing countries. Spot markets allow for greater flexibility to balance supply and demand so as to swiftly react to changing market conditions.*

[233] *According to the* Groupe International des Importatuers de Gaz Liquefié *(GIIGNL), contracts covering the sale of nearly 30 Million Tons (Mt) per year to Asian countries will come up for renewal over the next decade. It is expected that greater flexibility, especially with regard to the destination clause, more attractive pricing structuresand free on board (fob) pricing will become more and more frequent.*

Box 5.1: Price Structure in the Main LNG Markets

Although the LNG trade is expected to become an increasingly important source of supply to meet the world's demand for natural gas, there is no world gas market today, and approximately 85 percent of the gas consumed today in the world is produced locally.[234] The increase in LNG trade will eventually bring more integration among regional markets. Until then, LNG exporters, like Yemen, will face three main distinct and relatively independent markets, each with its own pricing structure and risk:

- In the United States, LNG imports face the competition of pipeline natural gas. The benchmark price[235] is either a specified market in long-term contracts or the HH price for short-term sales. LNG importers/exporters are exposed to a significant level of risk because of the high volatility in U.S. natural gas prices;
- In Europe, LNG prices are related to low-sulfur residual fuel oil, but a growing natural gas spot and futures market prices has developed in the recent past; and
- In Asia, prices are linked to imported crude oil.[236] The pricing formula generally includes a base price indexed to crude oil prices, a constant, and often a mechanism for the review/adjustment of the formula.

Gas Price Volatility and Government Revenue

Countries that derive a considerable portion of their revenue from exploiting nonrenewable resources such as hydrocarbons, typically face two problems: the revenue stream is uncertain and volatile; and it does not last forever. Volatile and uncertain fiscal revenue makes it difficult to plan expenditure and to efficiently use public resources. In order to ensure fiscal sustainability, when revenue falls sharply and unexpectedly, often governments respond with expenditure cuts. This can be expensive, inefficient and politically unpopular. In addition, it is not easy to distinguish, ex ante, a permanent price shock from a transient one: oil and gas prices have been known to be mean-reverting, but the mean they revert to may not be the same over time. If the price increases substantially, a government may be under pressure to increase its spending, but it may be difficult to do it efficiently.

To help deal with these problems, some countries have established resource revenue funds. A resource fund could be structured to specifically deal with price volatility, that is, the fund would accumulate during period of high commodity prices. The resources so accumulated would be used to offset revenue fluctuation in periods of low commodity prices. This type of fund is known as

[234] *EIA Energy Outlook 2006.*

[235] *Being a price-taker, LNG is priced with reference to the competing fuel.*

[236] *Since LNG importers in the Pacific Basin – Japan, Korea and Taiwan – had little to no domestic gas production, and no pipeline sources for natural gas imports, starting in the 80s, LNG trade increased very rapidly in these countries – compared to Europe and the United States – as they sought alternatives to oil. Security of supply was a more important consideration than price.*

Contingent Stabilization Fund (CSF).[237] In order to provide a meaningful insurance against price volatility, the CSF would need to be able to accumulate sufficient liquidity.[238] Countries experience with CSFs has been mixed.[239] In general terms, a CSF can contribute to insulate government expenditure from price shocks. However, its effectiveness depends on the government's overall fiscal discipline.

Instead of creating a CSF, a government could borrow abroad to weather temporary shocks or to adjust to permanent price shocks. In practice, the government may not have easy access to foreign capital markets on reasonable terms, especially in period of low commodity prices, and repaying the debt when the situation reverses may be difficult.

Another way of dealing with price volatility could be to set fiscal prices for the purpose of calculating royalties, production-sharing and corporate taxes. The fiscal price could be defined as a fixed value over a certain period of time, or it could be indexed to an international commodity price index[240] or a portfolio of indices.[241] It is important to underline that although the use of fiscal prices may allow the government to reduce revenue volatility, it is likely to have a distortive effect on investment decisions.[242]

Alternatively, a producing country could transfer the risk of price shocks to those better able to bear it. There are various ways of doing this:

- If the State is a party to a gas sales and purchase agreement, floors and ceilings could be established in the pricing mechanism.[243] These provisions are designed to provide a minimum sales price to the seller. In exchange for this protection, the buyer is ensured a maximum purchase price. Alternatively, a less risk adverse seller may prefer to negotiate a lower floor, and maintain the possibility to benefit from a rise in price. Indexation and periodic renegotiation of the price floor and ceiling are usually provided for in this type of agreements; and

- Futures and options markets provide the seller (buyer) the ability to either put a floor (ceiling) on prices or buy an insurance against falling (rising) prices. These contracts are called

[237] *Since natural resources are nonrenewable, their production straddles several years into the future, and the production rate tends to decline over the life of a field, a revenue fund may be created to set aside revenue for periods of lower revenue, because the price of the resource has fallen, or the production rate has lowered, or the resource has been fully produced. Stabilization funds aim at reducing the impact of volatile revenue on government expenditure, while saving funds aim at storing wealth for future generations. A resource fund can, of course, combine both elements, and accumulation and withdrawal rules can be designed to suit the objective of the fund and the particular needs and situation of a country. For simplicity, in this report we refer to a particular type of resource funds, the CSF. However, our conclusions apply to resource funds in general.*

[238] *This, of course, would depend on the expected level of revenue in relation to the spending needs of the country.*

[239] *Extensive literature exists on resource revenue funds and their effectiveness in various countries. For more details, see Fiscal Policy Formulation and Implementation in Oil Producing Countries, Davis, Ossowsky, Fedelino, IMF 2003, and Experience with Oil Funds: Institutional and Financial Aspects, Bacon and Tordo, ESMAP, Report No. 321/06.*

[240] *For example, in the case of gas, the fiscal price could be indexed to the average daily closing spot of HH NYMEX over a set period of time preceding the calculation of the royalty and tax revenue.*

[241] *For example, the fiscal price could be indexed to a basket of gas prices established as the average of the spot price in key export markets over a set period of time weighted on the basis of volumes of export.*

[242] *Even if a government should define the fiscal price on the basis of a basket of international gas prices, it is unlikely that this would match each contractor's sales price. Thus, the fiscal price would likely create an additional basis risk, which may affect the risk profile of the project (hence the cost of capital), and which would need to be taken into account by the contractor in the design of its risk mitigation strategy.*

[243] *Project finance lenders often require collars to be established in order to reduce commercial risk. Collars may be established in sales agreements or through the use of derivatives. Using derivatives may provide more flexibility to the parties as it would allow them to adjust their risk protection strategy at changing market conditions – although this would require more active risk management techniques and market expertise.*

derivatives.[244] Derivatives may be traded in exchanges or Over-The-Counter (OTC).[245] Although they mitigate price volatility, these instruments present different degrees of risk and complexities, and entail a certain level of implementation costs. Box 5.2 outlines the main features of the basic type of derivatives contracts.

Box 5.2: Key Elements of the Main Derivatives Contracts

- *Forward* contracts provide for the seller to deliver a certain type, quality and quantity of commodity for a specified price at a specified date and location. The simplest forward contract sets a fixed (firm) price. More elaborate price-setting mechanisms include floors, ceilings and inflation escalators. By setting such a price, the buyer and seller are able to reduce or eliminate uncertainty with respect to the sale price of the commodity in the future. Forward contracts are designed to be flexible so as to match the commercial needs of the parties entering into them. However, buyers and sellers have to find each other and settle on a price and contract conditions. Finding suitable counterparties and discovering the market price for a delivery at a specific place far into the future, may not be an easy task;

- *Futures* are similar to forward contracts as they obligate each party to buy or sell a specific amount of a commodity at a specified price.[246] Unlike forward contracts, buyers and sellers of futures contracts deal with an exchange, not with each other. Credit and default risk are mitigated by establishing "margins."[247] The price of futures is public, as is the volume of trade. The contract terms are standard and non-negotiable. A party who elects to hold the contract until maturity is guaranteed the price it paid when it initially bought

[244] *Derivatives owe their name to the fact that they derive their value from an underlying asset. These contracts do not confer ownership rights on the underlying asset. For example, a call option on BP stock gives its holder the right to buy a specific quantity of BP's share at a specified price (the "strike price"). The option does not represent an ownership interest in BP (the "underlying asset"). Although derivatives have been used for long time in the financial sector, their use in the energy sector is relatively new, and has been favored by market deregulation.*

[244] *The instruments are essentially the same, but the two markets differ in their transparency (the OTC energy market is not nearly as transparent as the OTC foreign exchange market), flexibility (contracts terms are not standardized as they are on exchanges), and cost. (In the OTC market, the counterpart is not a regulated exchange: transactions are entered into with a trader or financial institution, who in turn hedges the position in the market, or between parties with opposite hedging needs, for example, a gas producer and a utility company. Because contract performance is not guaranteed by an exchange, the risk that a party may default needs to be factored into the OTC contract. Therefore the transaction fees for the same transaction may differ greatly depending on the creditworthiness of the parties. In addition, because the terms of the contract are not standard, legal work is required, depending on the complexity of the trade.) Nevertheless, producers tend to prefer the OTC market since products can be structured to more closely replicate their project/market activity and needs. Furthermore, as OTC transactions are not publicly observed, a market participant is able to execute large volume trades discretely, thus reducing the potential for triggering an adverse movement of price that undermines the participant's own position.*

[246] *Futures contracts are available for only a few commodities/delivery locations, and for a relatively short time into the future. For longer duration and/or specific needs, OTC contracts may be used.*

[247] *The seller of the futures is asked to make a good-faith deposit with his broker, and a margins account is opened. The first deposit on the margin account is called initial margin, and is normally a fixed amount per contract. During the period of validity of the contract, the futures price will change in response to new information about the demand and supply of the underlying commodity. If the new price is higher than the contract price, the seller pays the difference into its margin account. If the new price is lower than the contract price, the broker pays the difference into the seller's (buyer's) margins account. This procedure is called "marking to market." It is done every day and may be done several times during the day. Brokers close out parties unable to pay (make their margin calls) by selling their clients' futures contracts. Usually, the initial margin is enough to cover a defaulting party's losses. If not, the broker covers the loss. If the broker cannot, the exchange does. The margin procedure applies to both the seller and the buyer of a futures contract.*

the contract.[248] However, because positions can be closed before maturity, a party can sell (buy) futures even though it has no access to the underlying commodity (use of the commodity);[249]

- *Options* give the buyer of the contract the right to buy (a call option) or sell (a put option) at a specified price (the "strike price") over a specified period of time.[250] An option can be compared to an insurance policy: the holder of an insurance policy pays a premium to insure against the risk of an adverse event.[251] The premium is paid upfront, whether or not the adverse event actually occurs. The more likely the event, the higher the premium.[252] Options can be used successfully to put floors and ceilings on prices; and

- *Swaps*. A swap contract is an agreement between two parties to exchange a series of cash flows generated by underlying assets. No physical asset or principal amounts is actually transferred between the buyer and the seller. For this reason, a base, the "notional amount" of the contract, is established in order to determine the amounts that will periodically be swapped. The contracts are entered into between the two counterparties outside any centralized trading facility or exchange.[253] Many of the benefits associated with swap contracts are similar to those associated with futures or options contracts, that is, they allow users to manage price exposure risk without having to take possession of the commodity. Swaps differ from exchange-traded futures and options in that, because they are individually negotiated instruments, users can customize them to suit their risk management activities to a greater degree than is easily accomplished with more standardized futures contracts or exchange-traded options.

Information on the use of and experience with commodity risk markets by governments (and/or State-owned companies) is scarce.[254] This is partly due to the confidentiality and the unwillingness of producers to reveal market-sensitive information, especially when large transactions are involved, as it is often the case when the traded commodity is oil or gas. In addition, the gas derivatives have only recently been introduced in stock exchanges,[255] and

[248] *Since the buyer of the futures contract can always demand delivery and the seller can always insist on delivering, at maturity the futures price and the spot market price for that commodity will have to be the same.*

[249] *Speculators routinely buy and sell futures contracts in anticipation of price changes. Intuitively, forward contracts are less liquid than futures contract.*

[250] *American options allow the buyer to exercise its right either to buy or sell at any time until the option expires. European options can be exercised only at maturity. Whereas the holder of a futures/forward contract has an obligation to perform – that is, the holder is committed to a price in advance – an option gives its holder a right to choose whether or not to perform.*

[251] *As with futures contracts, speculators also buy and sell options in anticipation of market prices changing.*

[252] *The price of an option depends upon its strike price (the purchase or sale price of the commodity in the contract), the price of the underlying commodity (the current futures price for the specific month the option covers), the time of expiration, the interest rates and the volatility.*

[253] *Since OTC transactions are not publicly observed, a market participant is able to execute large volume trades discretely, thereby reducing the potential for an adverse movement of price that undermines the participant's own position. Furthermore, because contracts are not guaranteed by the exchange, the risk of default of a party to the contract is higher*

[254] *There is a general consensus among market participants that developing country producers, and especially gas producers, have so far made limited recourse to oil and gas risk markets to insure against price volatility.*

[255] *Gas futures and options were introduced in stock exchanges only 15 years ago. In addition, the more liquid segment of the futures market is the near term. Therefore, a government that wishes to lock in a price for the budget period (12 months) and does not have the capacity, or is unwilling to take the risk of actively trading in futures and/or options, would need to use the OTC market. Information on transactions conducted in the OTC market is not publicly available.*

long-term contracts with embedded price formulae are still very much the norm. Frequently cited reasons for the relatively low use of hedging by governments in producing countries are listed below:

- Policy makers might be reluctant to take the political risks associated with it. If the State lost significant sums as a result of its hedging program, or if prices increased significantly and the State had sacrificed that upside to reduce the volatility in its resource revenue, the conventional wisdom is that public criticism would be harsh;[256]

- A hedging program costs money: margins need to be deposited with a stock exchange if futures are used; options require immediate payments; and OTC traders may require credit guarantees. Governments with a poor credit standing may find their access to certain hedging instruments constrained or expensive;

- Some aspects of a hedging program would require specific appropriations for any fees or commissions or initial margins associated with the program;[257]

- Before the State could initiate a commodity hedging program, it is quite possible that the legislature would have to pass a law that authorized and spelled out the program's parameters. This may be politically difficult to achieve;

- The personnel and cost implications of designing, implementing and monitoring a hedging program may be significant. Expertise is required to understand the risk structure, identify appropriate risk management instruments, implement and supervise the program. Although the design and implementation of a hedging program may be subcontracted, the government would still need to develop sufficient internal capacity to monitor the program and communicate its results to the relevant stakeholders. Adequate reporting and accounting procedures would also be required; and [258]

- The basis risk of the particular commodity may be too high,[259] and it may not be significantly reduced by using exchange traded contracts.

Notwithstanding the foregoing, governments appear to be making increased use of derivatives to protect their hydrocarbon revenue. Several oil- and gas-producing States have legislation, administration guidelines and procedures

[256] *See A. Kuprianov, Derivatives debacles: Case studies of large losses in derivatives markets, pp. 605-631 R.J. Schwartz, W.S. Clifford, in* Derivatives Handbook: Risk Management and Control, *John Willey & Sons, Inc.*

[257] *For example, if the State were required to put up large amounts from time to time to cover margin requirements in a futures-based program, budget appropriations would need to be granted.*

[258] *Accounting and reporting standards have been developed, although with particular reference to companies and stock exchange regulation.*

[259] *The basis risk describes the lack of correlation that may exist between the price of a derivative contract and the price of the commodity that is being hedged. To the extent that these prices move independently, the hedger faces a risk that the change in the value of the commodity may not be entirely offset by the change in the value of the derivative position. Thus, the hedge may not be a perfect one. A basis risk may occur because of quality differential between the commodity linked to the derivative contract and the commodity being hedged, for example, the Brent IPE futures and the Doba blend, or the WTI NYMEX and the Lloyd blend. This is not unusual for heavy acidic crudes. In the case of natural gas, the basis risk is greatly linked to location – for example, the cost of transporting the gas from one location (the HH if derivatives quoted on the NYMEX are used) to another. The use of price formulae in contracts may also introduce a basis risk: this is, for example, the case when using long-run moving average of spot prices. The basis risk may have a timing dimension: although spot and futures prices for the same commodity are closely related a change in the spot price does not necessarily translate in the same change in futures price. This is because the same piece of information may affect current supply/demand and future supply/demand in a different way. A variety of basis contracts are available in OTC markets to hedge locational, product and even temporal differences between exchange-traded standard contracts and the particular circumstances of contract users.*

permitting the institution of hedging programs to protect their energy revenues,[260] and State-owned utility companies – particularly in Europe and in the United States – are increasingly making use of derivative contracts to hedge against gas price volatility.

In order to design the proper risk management plan, the government would need to clearly define its objectives, that is, what results it expects to obtain from hedging and the time frame for such results.[261] For example, a government that derives a large portion of its fiscal revenue from gas, may wish to limit the risk of revenue volatility by securing a fixed price for the entire budget year in order to support its expenditure plan, or it may wish to limit the risk that the price may fall below a certain minimum level over a longer period of time for the purpose of ensuring the medium- or long-term fiscal sustainability.

The market outlook (contango, flat or backwardation),[262] the level of price volatility and the government's expectation with respect to the direction of future price movements, are important elements to determine the most suitable hedging strategy. For example, if the market is in backwardation, and the government expects that it will continue to be so over the hedging period, and that price volatility will be low, it could adopt a strategy of simple forward sales selling futures and closing out its position with a reverse transaction before the expiry date.[263]

The relationship between the price of the hedge instrument and the price of the underlying commodity would need to be carefully analyzed in order to determine the optimal hedge ratio.[264]

The relative cost of the various hedge instruments also plays a relevant role in designing the strategy. Since the gains and losses in futures contracts are settled daily, a strategy of trading in futures may involve large transfers of cash to and from the broker. The number of transfers could be reduced by structuring an OTC swap to suit the government's liquidity profile. Alternatively, the government might use a straight option strategy which does not involve the payment of margins,[265] but the buyer of the option pays the premium upfront.[266] The level of funding that is available to the government to set up a risk management program, and the

[260] *The experience of the state of Texas in designing its hedging program and related institutional set-up could offer a valuable reference guide to governments that are looking at ways to protect their revenue from commodity price volatility. Among the national oil companies, Statoil has adopted a comprehensive approach to enterprisewide risk management strategies. PDVESA (the national oil company of Republica Bolivariana de Venezuela), Pemex (the national oil company of Mexico) and Petrobras (the national oil company of Brazil), also have active hedging programs.*

[261] *For a discussion of potential hedging objectives, See C. Ellsworth, E. N. Krapels and S. H. Cho,* Natural Gas Hedging: Benchmarking Price Protection Strategies, *Risk Books, 1999.*

[262] *The market is in contango when near-term prices are lower than prices for the months further in the future, and is in backwardation when near-term prices are higher than future prices.*

[263] *The government could sell a 12-month strip, that is, a futures contract covering a period of 12 months, and close out its position gradually according to the pattern of the gas revenue being hedged. Alternatively, the government could adopt a rollover strategy, that is, sell futures and close out the position monthly.*

[264] *In order for the hedge to be successful, the futures price and the underlying spot prices should behave similarly, even though a basis risk will naturally exist. Econometric models are used to determine the optimal hedge ratio, that is, the ratio of derivatives contracts to buy or sell for each unit of the underlying asset on which the hedger bears a price risk. Since spot and futures returns are characterized by time-varying distributions, optimal hedge ratios should be time-varying. For a more in-depth discussion, See R.J. Schwartz, W.S. Clifford Jr (Eds.),* Derivatives Handbook: Risk Management and Control, *John Willey & Sons, Inc, 1997.*

[265] *Futures-style options exist where the premium is not paid upfront and a daily adjusted margin is required.*

[266] *The upfront cost is likely to be more than a hedging program using futures, but an options-based program would allow the government to retain any additional revenue if gas prices move higher than the hedged level. Furthermore, the cost of the premium can be totally or partially eliminated by using a combination of put-and-call options (for example, selling a put and buying a call option).*

procedure and constraints for accessing such funding, will ultimately determine the type of instruments that the government will be able to use to hedge its risk exposure, and the overall organization of the program.

The implementation infrastructure is very important. For any risk management program to perform effectively, a system of checks and balances would need to be designed. Trades, financial transactions and exposures should be clearly recorded to permit the evaluation of performance of the system and to promote accountability. Ideally, a risk management committee would be tasked with the design of the hedge policy on the basis of relevant economic and price information and of the tolerated level of risk exposure. The committee would also establish the hedging guidelines (budget, time horizon for hedging, and authorizations) to be followed by a hedge committee, tasked with the implementation of the hedge policy, either directly or supervising external hedgers. Audit and financial control should be independent, that is, not part of the committee's structure. The risk management policy should be presented to the national assembly together with the relevant budget documents, as well as postexecution assessments. This type of structure would enhance transparency and accountability.[267]

Before implementing a particular strategy, it is good practice to set up a virtual hedging program where different hedging strategies would be explored for a suitably long period of time to determine their effectiveness, the relative costs and ease of implementation.

It is important to note that the setting up of a risk management program through the use of derivatives contract is not alternative to the establishment of a CSF. On the contrary, the two instruments can be complementary:[268] because derivatives can be used to reduce price volatility, the need to recur to withdrawals from the CSF when actual price level fall in relation to their target level, would also be reduced. This would permit the CSF to build its reserves more steadily and to invest in less liquid instruments thus increasing the return on assets.

Annex 6 illustrates simple examples of hedging strategies using exchange-traded and OTC derivative contracts from the point of view of a government of a gas-producing country.

Conclusions

The gas reserves base in Yemen has been the object of speculation over the past years. At the end of 2005, proven gas reserves were estimated to be 16.9 Tcf, of which approximately 9 Tcf had been committed to the YLNG project, and the rest has been earmarked for domestic consumption.

The development of a natural gas market is particularly important to GoY for its potential to support the creation and growth of the domestic industrial sector. In addition, revenue from gas exports may contribute to partially offset the decline in government revenue from currently producing oilfields.

Little data are available on the potential size of probable and possible reserves, and on the likely

[267] *For examples of alternative implementation arrangements, See S. Claessens and P. Varangis, Hedging Crude Oil Imports in Developing Countries, The World Bank, WPS 775, August 1991, or M. Lindahl and D.T. Weinmann, Hedging Oil Revenues: Texas and Alaska, presented at the International Association for Energy Economics in July 1995.*

[268] *An illustration of how the use of derivatives can complement the use of CSF is given in S.S. Claessens and P. Varangis, Oil Price Instability, Hedging and an Oil Stabilization Fund, the Case of Venezuela, The World Bank, WPS 1290, April 1994.*

cost of development. The available data would seem to indicate a relatively low chance of finding large oil and gas fields, and a relatively high chance that development cost could be higher than the regional average. This does not mean that gas reserves would not be found in Yemen, or that it would not be economic to develop them. On the other hand, it does suggest that measures may need to be taken to encourage their development. In order to design appropriate measures, GoY would first need to identify if barriers to investment exist, and what their nature is. In this report, we identified a number of potential barriers to investment, and possible options were suggested to overcome them.

The use of fiscal policy to attract foreign capital and expertise was also discussed. Because of the high risk and considerable investment involved in gas exploration and development, the fiscal system would need to take into account the divergent interests of investors and GoY. In particular, the fiscal system would need to be able to allocate risks equitably. As risks can be substantially different for different projects and, over time, it would be desirable to build enough flexibility into a system to allow for unforeseen changes, and to minimize the need and cost of negotiations and/or renegotiations. Ideally, the system should be able to capture the "economic rent" when project conditions are favorable, and, at the same time, provide some early revenue. Although it is theoretically possible for the government to obtain the same economic benefit by combining alternative fiscal instruments, in practice, fiscal instruments respond differently to changes in project variables. As it is not possible to anticipate exactly how each project will perform, the government will need to design a fiscal system that is likely to accommodate the majority of the projects or conditions. In other words, the system should aim at optimizing fiscal revenue at the country level as opposed to optimizing fiscal revenue at the project level. The use of fiscal systems based on profitability indices (R-Factor and rate of return-based systems) was suggested as they are more likely to capture the variability among projects. A study on the likely field size, location, probability of success, reservoir performance, finding and development cost, and other relevant technical parameters would need to be carried out in order to design fiscal system's parameters that are appropriate for Yemen.

Risk-reward profiles vary from investor to investor and, over time, fiscal models that limit the upside for the investor but cushion the downsides, may be more suited to promote a new or geologically risky province, or to attract small investors during times of high volatility in the market. In the latter case though, the host government needs to consider the macrofiscal impact of this strategy, including the need for utilizing risk management tools.

Countries that derive a considerable portion of their revenue from exploiting nonrenewable resources, such as hydrocarbons, typically face two problems: the revenue stream is uncertain and volatile, and it does not last forever. Volatile and uncertain fiscal revenue makes it difficult to plan expenditure, and to efficiently use public resources. Despite careful planning, exogenous forces can still cause actual revenue to fall below its budgeted level. Faced with a revenue shortfall, governments may have to cut expenditure or use debt to finance the shortfall, as increasing nonoil/gas revenue may not be feasible in the short term.

Depending on the reference market, oil and gas prices show a high degree of correlation. The higher the correlation between oil and gas prices at the basis of GoY's revenue stream, the less effective the use of a commodity diversification strategy for mitigating price volatility, that is, by adding gas to its revenue stream, GoY may not be able to substantially reduce the volatility of its revenue stream.

To insulate revenue from unexpected price falls, different risk management instruments could be considered, ranging from the creation of CSFs, to the use of market-based risk management instruments. Some instruments are more suited to manage short-term price volatility, while others provide a more effective protection against long-term price volatility. In particular, the use of market-based risk management instruments (derivatives) could be more suited to stabilize GoY's revenue in the short term, while a stabilization fund could be created to manage the remaining interperiod volatility or more general risks related to the management of nonrenewable resource revenue.

Expertise is required to understand the risk structure, identify appropriate risk management instruments and implement and supervise a risk management program. The design and implementation of a hedging program may be subcontracted, but the government would still need to develop sufficient internal capacity to monitor the program and communicate its results to the relevant stakeholders. Similar considerations apply to the design and management of investment strategies for a stabilization fund.

The financial, legal and institutional implications of setting up a risk management program vary according to the type of instrument used. Commodity hedging programs may require the passing of legislation to authorize the program and establish the boundary conditions for its implementation. Stabilization funds also require specific legislation regulating the objectives, the rules for accumulation into and withdrawal from the fund, and its governance structure.

No risk management program is without risk. The objective of the program, its governance and the principles to be used to define its success, would need to be clearly specified at the outset and communicated to the parliament and the civil society. The political implications of implementing and managing the outcome of these programs should not be underestimated.

Finally, before implementing a particular risk management program, it is good practice to set up a virtual program where different risk management and hedging strategies would be explored for a suitably long period of time to determine their effectiveness, the relative costs and ease of implementation.

Annex 1
Government and State Revenue from Gas Sales

Table A1.1: Revenue Generated from Gas Sales to the Power Sector

		360 MW Marib I		*400 MW Marib II*		*400 MW Maber I*		*96 MW Hizyaz I & II*		*150 MW Raz Katnib*		*800 MW Maber II*		*160 MW Makha*		*125 MW Al-Hiswa*		*64 MW Al-Mansoura*			
Year	OCGT Plant (MW)	Gas Quantity (MMBTU)	Price (MMBTU)	Gas Quantity (MMBTU)	Price (MMBTU)	Gross Quantity (MMBTU)	Price (MMBTU)	Gross Quantity (MMBTU)	Price (MMBTU)	Gas Quantity (MMBTU)	Price (MMBTU)	Gas Quantity (MMBTU)	Price (MMBTU)	Gas Quantity (MMBTU)	Price (MMBTU)	Gas Quantity (MMBTU)	Price (MMBTU)	Gas Quantity (MMBTU)	Price (MMBTU)	Total Gas Quantity (MMBTU)	Gross Government Revenue (US$ Million)
2008	360	20.7	0.7																	20.7	**14.5**
2009		20.7	0.7																	20.7	**14.5**
2010	400	20.7	0.7	23.0	0.7															43.8	**30.6**
2011		20.7	0.7	23.0	0.7															43.8	**30.6**
2012	400	20.7	0.7	23.0	0.7	23.0	2.6													66.8	**90.5**
2013	96	20.7	0.7	23.0	0.7	23.0	2.6	5.5	2.6											72.3	**104.9**
2014		20.7	0.7	23.0	0.7	23.0	2.6	5.5	2.6											72.3	**104.9**
2015	150	20.7	0.7	23.0	0.7	23.0	2.6	5.5	2.6	8.6	2.6									81.0	**127.4**
2016	800	20.7	0.7	23.0	0.7	23.0	2.6	5.5	2.6	8.6	2.6	46.1	2.6							127.1	**247.2**
2017		20.7	0.7	23.0	0.7	23.0	2.6	5.5	2.6	8.6	2.6	46.1	2.6							127.1	**247.2**
2018	160	20.7	0.7	23.0	0.7	23.0	2.6	5.5	2.6	8.6	2.6	46.1	2.6	9.2	2.6					136.3	**271.2**
2019	125	20.7	0.7	23.0	0.7	23.0	2.6	5.5	2.6	8.6	2.6	46.1	2.6	9.2	2.6	7.2	2.6			143.5	**289.9**
2020	64	20.7	0.7	23.0	0.7	23.0	2.6	5.5	2.6	8.6	2.6	46.1	2.6	9.2	2.6	7.2	2.6	3.7	2.6	147.2	**299.5**
2021		20.7	0.7	23.0	0.7	23.0	2.6	5.5	2.6	8.6	2.6	46.1	2.6	9.2	2.6	7.2	2.6	3.7	2.6	147.2	**299.5**
2022		20.7	0.7	23.0	0.7	23.0	2.6	5.5	2.6	8.6	2.6	46.1	2.6	9.2	2.6	7.2	2.6	3.7	2.6	147.2	**299.5**
2023		20.7	0.7	23.0	0.7	23.0	2.6	5.5	2.6	8.6	2.6	46.1	2.6	9.2	2.6	7.2	2.6	3.7	2.6	147.2	**299.5**
2024		20.7	0.7	23.0	0.7	23.0	2.6	5.5	2.6	8.6	2.6	46.1	2.6	9.2	2.6	7.2	2.6	3.7	2.6	147.2	**299.5**
2025		20.7	0.7	23.0	0.7	23.0	2.6	5.5	2.6	8.6	2.6	46.1	2.6	9.2	2.6	7.2	2.6	3.7	2.6	147.2	**299.5**
2026		20.7	0.7	23.0	0.7	23.0	2.6	5.5	2.6	8.6	2.6	46.1	2.6	9.2	2.6	7.2	2.6	3.7	2.6	147.2	**299.5**
2027		20.7	0.7	23.0	0.7	23.0	2.6	5.5	2.6	8.6	2.6	46.1	2.6	9.2	2.6	7.2	2.6	3.7	2.6	147.2	**299.5**
2028		20.7	0.7	23.0	0.7	23.0	2.6	5.5	2.6	8.6	2.6	46.1	2.6	9.2	2.6	7.2	2.6	3.7	2.6	147.2	**299.5**
Total	**2,555**	**435.5**		**437.8**		**391.7**		**88.5**		**121.0**		**599.0**		**101.4**		**72.0**		**33.2**		**2,279.9**	**4,268.7**

Note: This revenue stream is calculated based on the assumption that all gas to the power sector is coming from GoY, as the owner of the current proven gas reserves in Block 18. It is further assumed that all plants are OCGT plants.

Source: Authors' estimate.

Table A1.2: HFO Fuel Cost for Power Generation

Year	Oil-fired Plant (MW)	Quantity (Million tons of HFO)	Yemen Oil Price/bbl			Yemen HFO/ton			PEC HFO Consumption (US$ Million)		
			Brent Low Case	Brent Base Case	Brent High Case	Brent Low Case	Brent Base Case	Brent High Case	Brent Low Case	Brent Base Case	Brent High Case
2008	360	0.51	45.7	55.7	61.2	205.0	249.9	275.0	105.1	128.2	141.0
2009		0.51	41.7	48.4	63.7	187.2	217.3	286.0	96.0	111.4	146.7
2010	400	1.08	37.6	44.5	67.0	168.7	199.8	300.6	182.6	216.3	325.5
2011		1.08	33.8	42.6	69.7	151.7	191.1	312.8	164.3	206.9	338.7
2012	400	1.65	30.6	41.2	73.2	137.4	185.0	328.9	227.1	305.7	543.4
2013	96	1.79	29.3	40.5	77.4	131.4	181.8	347.4	235.2	325.3	621.6
2014		1.79	28.7	40.9	81.1	128.8	183.6	364.1	230.5	328.4	651.5
2015	150	2.00	28.3	41.8	85.0	126.9	187.8	381.5	254.2	376.1	764.0
2016	800	3.14	28.6	42.5	88.9	128.6	190.7	399.0	404.1	599.4	1,253.8
2017		3.14	29.9	45.4	96.1	134.0	203.9	431.6	421.2	640.6	1,356.3
2018	160	3.37	31.1	47.9	103.7	139.6	214.9	465.4	470.4	724.1	1,568.5
2019	125	3.55	31.8	49.5	106.6	143.0	222.1	478.5	507.4	788.2	1,697.8
2020	64	3.64	32.6	51.1	110.0	146.5	229.5	494.0	533.1	835.3	1,797.7
2021		3.64	33.4	53.6	113.6	150.1	240.7	510.1	546.2	875.9	1,856.4
2022		3.64	34.2	55.5	117.3	153.8	249.0	526.7	559.6	906.3	1,916.8
2023		3.64	35.1	57.3	121.0	157.5	257.2	543.4	573.1	936.0	1,977.5
2024		3.64	35.9	59.2	124.9	161.3	265.7	560.6	587.0	966.9	2,040.4
2025		3.64	36.8	59.6	128.8	165.2	267.7	578.5	601.2	974.3	2,105.2
2026		3.64	37.7	61.3	132.8	169.2	275.2	596.5	615.6	1,001.5	2,170.9
2027		3.64	38.6	63.0	137.0	173.2	283.0	615.3	630.5	1,029.8	2,239.3
2028		3.64	39.5	64.8	141.4	177.4	290.9	634.7	645.7	1,058.9	2,309.9
Total	**2,555**	**56.38**							**8,590**	**13,336**	**27,823**

Note: A correlation coefficient of 0.9716 between Brent and 3.5% HFO was assumed.

Table A1.3: Government and State Revenue from LNG Export – Low Price Scenario

					Government Take							State Take			
												YGC			
Year	HH AOE/07	JCC WB/ELA	Gross Quantity (MMBTU)	Total Project Revenue	Royalty	Bonuses	Fixed Tax	Profit Share	FTP Advance	FTP Reimb	Total	Pjct	Ups. Fee	Pension Fund	Total
up to 2008				–	–	17.0	38.7	–	–	–	55.7	–	–	(120.2)	(64.5)
2009	6.80	36.1	275	1,067.7	21.4	11.0	3.3	130.8	–	–	166.4	38.6	6.1	11.5	222.6
2010	6.36	33.2	349	1,294.	2	25.9	1.0 1.9	158.5	–	–	187.3	52.4	7.4	29.2	276.3
2011	6.02	33.5	349	1,223.0	24.5	1.0	1.9	149.8	–	–	177.2	36.3	7.0	23.7	244.2
2012	5.71	33.9	349	1,158.2	23.2	1.0	2.0	141.9	–	–	168.1	29.8	6.6	21.1	225.5
2013	5.47	32.5	349	1,102.3	22.0	1.0	2.0	135.0	1.0	–	161.1	23.6	12.3	18.6	215.7
2014	5.48	31.8	349	1,135.1	22.7	1.0	2.0	139.0	–	(1.0)	163.7	32.6	12.7	20.6	229.7
2015	5.43	31.3	349	1,121.4	22.4	1.0	2.1	137.4	–	–	162.9	35.0	12.2	20.7	230.7
2016	5.69	31.8	349	1,174.0	23.5	11.0	2.1	172.6	–	–	209.2	39.9	15.3	21.5	285.8
2017	5.89	32.4	349	1,214.0	24.3	1.0	2.9	178.5	–	–	206.7	38.4	14.8	20.4	280.2
2018	6.01	33.1	349	1,237.7	49.5	11.0	3.5	207.9	0.4	–	272.4	53.8	17.6	16.1	359.8
2019	6.18	33.8	349	1,295.4	51.8	1.0	2.2	217.6	–	(0.4)	272.3	86.9	18.4	26.0	403.6
2020	6.30	34.5	349	1,320.4	52.8	1.0	2.3	221.8	–	–	277.9	91.8	18.8	27.4	416.0
2021	6.64	35.3	349	1,390.9	55.6	1.0	2.3	302.8	–	–	361.8	123.9	19.8	37.0	542.5
2022	7.04	36.2	349	1,478.9	88.7	1.0	2.4	373.9	–	–	466.0	120.3	19.8	36.0	642.1
2023	7.25	37.1	349	1,524.8	91.5	1.0	2.4	387.0	0.2	–	482.1	124.4	20.4	37.2	664.1
2024	7.67	38.0	349	1,643.2	98.6	1.0	2.8	421.0	–	(0.2)	523.1	130.1	22.0	38.9	714.0
2025	7.75	38.9	349	1,661.5	99.7	11.0	2.5	612.2	–	–	725.4	104.0	60.3	31.1	920.8
2026	8.07	39.8	349	1,731.4	138.5	1.0	2.6	632.0	–	–	774.1	106.3	62.9	31.8	975.0
2027	8.33	40.8	349	1,838.6	147.1	1.0	2.6	700.8	–	–	851.5	117.8	21.1	35.2	1,025.5
2028	8.57	41.8	349	1,887.5	151.0	1.0	2.7	731.3	–	–	886.0	122.9	–	36.7	1,045.6
			6,906.0	**27,500.2**	**1,234.7**	**77.0**	**87.1**	**6,151.8**	**1.7**	**(1.7)**	**7,550.6**	**1,508.7**	**375.4**	**420.5**	**9,855.2**

Source: Authors' estimate.

Table A1.4: Government and State Revenue from LNG Export – Base Price Scenario

					Government Take							State Take			
Year	HH AOE/07	JCC WB/EIA	Gross Quantity (MMBTU)	Total Project Revenue	Royalty	Bonuses	Fixed Tax	Profit Share	FTP Advance	FTP Reimb	Total	Pjct	YGC Ups. Fee	Pension Fund	Total
up to 2008			–		–	17.0	38.7	–	–	–	55.7	–	–	(120.2)	(64.5)
2009	7.33	42.5	275	1,160.3	23.2	11.0	3.3	142.1	–	–	179.6	51.9	6.1	15.5	253.0
2010	7.11	39.1	349	1,472.5	29.5	1.0	1.9	180.4	–	–	212.7	77.7	7.7	36.8	334.9
2011	6.71	39.4	349	1,384.6	27.7	1.0	1.9	169.6	–	–	200.2	59.3	7.3	30.6	297.4
2012	6.63	38.1	349	1,360.8	27.2	1.0	2.0	166.7	–	–	196.9	58.5	7.1	29.7	292.2
2013	6.54	37.5	349	1,336.8	26.7	1.0	2.0	163.8	–	–	193.5	57.4	12.3	28.7	291.9
2014	6.69	37.8	349	1,403.0	28.1	1.0	2.0	171.9	–	–	203.0	70.7	12.9	32.0	318.6
2015	6.73	38.7	349	1,411.9	28.2	11.0	2.1	207.6	–	–	248.9	69.2	14.6	30.9	363.6
2016	6.98	39.3	349	1,467.8	29.4	11.0	2.1	251.7	–	–	294.2	74.9	17.7	31.9	418.7
2017	7.38	40.8	349	1,576.0	31.5	1.0	2.9	270.3	–	–	305.7	82.4	17.3	33.5	438.9
2018	7.40	42.0	349	1,577.4	63.1	1.0	3.5	400.4	–	–	468.0	78.0	17.3	23.3	586.6
2019	7.45	43.3	349	1,625.1	65.0	1.0	2.2	439.8	–	–	508.0	103.0	17.8	30.8	659.6
2020	7.72	44.2	349	1,680.6	67.2	1.0	2.3	456.5	–	–	527.0	110.6	18.4	33.1	689.1
2021	7.87	45.7	349	1,711.0	68.4	11.0	2.3	664.3	–	–	746.0	113.7	50.9	34.0	944.6
2022	8.22	47.2	349	1,784.5	107.1	1.0	2.4	677.7	–	–	788.2	117.6	53.7	35.1	994.6
2023	8.58	49.5	349	1,860.2	111.6	1.0	2.4	710.1	–	–	825.1	123.0	56.0	36.8	1,040.9
2024	8.98	51.2	349	1,989.0	119.3	1.0	2.8	763.8	–	–	886.9	127.0	59.9	38.0	1,111.8
2025	9.15	52.8	349	2,022.0	121.3	1.0	2.5	781.3	–	–	906.2	134.0	60.9	40.0	1,141.1
2026	9.37	54.6	349	2,067.6	165.4	1.0	2.6	787.0	–	–	956.0	132.2	62.2	39.5	1,189.9
2027	9.69	56.1	349	2,134.7	170.8	1.0	2.6	836.6	–	–	1,011.0	140.5	21.7	42.0	1,215.2
2028	10.09	57.7	349	2,218.8	177.5	11.0	2.7	972.1	–	–	1,163.3	131.9	–	39.4	1,334.6
			–												
			6,906.0	**33,244.7**	**1,488.3**	**87.0**	**87.1**	**9,213.6**	**–**	**–**	**10,876.0**	**1,913.4**	**521.9**	**541.5**	**13,852.7**

Source: Authors' estimate.

Table A1.5: Government and State Revenue from LNG Export – High Price Scenario

					Government Take							State Take			
Year	HH AOE/07	JCC WB/EIA	Gross Quantity (MMBTU)	Total Project Revenue	Royalty	Bonuses	Fixed Tax	Profit Share	FTP Advance	FTP Reimb	Total	Pjct	YGC Ups. Fee	Pension Fund	Total
up to 2008			–	–		17.0	38.7	–	–	–	55.7	–	–	(120.2)	(64.5)
2009	7.97	46.7	275	1,257.9	25.2	11.0	3.3	154.1	–	–	193.5	65.9	6.1	19.7	285.1
2010	7.82	43.0	349	1,631.5	32.6	1.0	1.9	199.9	–	–	235.4	100.4	7.9	43.5	387.2
2011	7.77	43.3	349	1,617.5	32.3	1.0	1.9	204.5	–	–	239.8	91.3	7.8	40.1	379.0
2012	7.44	43.9	349	1,543.7	30.9	1.0	2.0	195.1	–	–	229.0	83.5	7.5	37.2	357.1
2013	7.48	46.2	349	1,551.4	31.0	1.0	2.0	191.4	–	–	225.4	88.0	12.3	37.8	363.6
2014	7.66	48.4	349	1,644.7	32.9	11.0	2.0	255.1	–	–	301.0	94.6	15.7	39.2	450.5
2015	7.84	50.7	349	1,681.1	33.6	11.0	2.1	310.1	–	–	356.7	96.2	17.0	39.0	509.0
2016	8.19	52.7	349	1,754.5	35.1	1.0	2.1	333.1	–	–	371.3	109.9	17.8	42.4	541.4
2017	8.59	54.8	349	1,840.5	36.8	1.0	2.9	534.4	–	–	575.2	81.5	17.3	33.3	707.3
2018	8.47	57.1	349	1,810.7	72.4	11.0	3.5	719.8	–	–	806.7	60.5	46.1	18.1	931.5
2019	8.23	59.3	349	1,794.3	71.8	1.0	2.2 7	10.9	–	–	785.9	85.3	45.7	25.5	942.3
2020	8.72	61.2	349	1,900.0	76.0	1.0	2.3	758.3	–	–	837.5	95.6	48.4	28.6	1,010.2
2021	9.24	62.9	349	2,011.2	80.4	1.0	2.3	808.2	–	–	892.0	139.4	51.2	41.7	1,124.3
2022	9.59	65.0	349	2,084.0	125.0	1.0	2.4	818.5	–	–	946.9	141.1	53.7	42.2	1,183.9
2023	10.17	67.1	349	2,209.4	132.6	1.0	2.4	873.7	–	–	1,009.7	150.4	56.9	44.9	1,261.9
2024	10.47	69.3	349	2,313.5	138.8	11.0	2.8	1,008.1	–	–	1,160.7	135.5	59.6	40.5	1,396.4
2025	10.86	71.4	349	2,397.0	143.8	1.0	2.5	1,052.8	–	–	1,200.1	147.4	61.8	44.1	1,453.3
2026	11.45	73.7	349	2,522.8	201.8	1.0	2.6	1,094.4	–	–	1,299.8	150.3	65.0	44.9	1,560.1
2027	11.91	76.1	349	2,620.8	209.7	1.0	2.6	1,168.8	–	–	1,382.1	160.5	17.3	48.0	1,607.9
2028	12.45	78.4	349	2,734.8	218.8	1.0	2.7	1,233.2	–	–	1,455.6	169.3	–	50.6	1,675.5
			6,906.0	**38,921.3**	**1,761.6**	**87.0**	**87.1**	**12,624.5**	–	–	**14,560.2**	**2,246.7**	**615.2**	**641.1**	**18,063.1**

Source: Authors' estimate.

Annex 2
Gas-In-Place

Gas-In-Place (GIP), April 2007

Trillion Cubic Feet (Tcf)

Block	Proven (1P)	Proven + Probable (2P)	Proven + Probable + Possible (3P)
Block-18 Marib	14.79	18.65	18.65
Block-5 Jannah	1.28	1.28	1.28
Block-S1 Damis	0.61	0.86	1.13
Block-9 Malik	0.23	0.43	0.89
Block-10 East Shabwah	0.45	0.63	1.09
Block-14 Masilah	0.21	0.27	0.33
Block-43 S. Hawareem	0.03	0.04	0.07
Block-32 Hawareem	0.01	0.02	0.03
Block-51 East Al Hajr	0.05	0.16	0.36
Block-S2 Uqlah	0.55	1.17	3.19
Block-53 East Saar	0.01	0.01	0.02
Total	**18.22**	**23.53**	**27.04**

Note: Information provide by PEPA, April 2007.

Annex 3
Tax and Nontax Instruments

Box A3.1: Royalties

How do they work?

- Royalties have historically been the most common method used by governments to gain revenues from the exploitation of the nation's mineral endowment;
- Royalties are based on either the volume ("*uni*" or "*specific*" royalty) or the value ("*ad valorem*" royalty) of production or export;
- Unit royalties impose burdens that vary inversely to changes in market price, while ad valorem royalties vary directly with price for any given level of production or sale; and
- In the petroleum industry royalties, are typically calculated on a netback basis, that is, the price base for royalty calculation is adjusted from the point of export to the well head by deducting transportation and other marketing costs.

Advantages and Disadvantages to Host Government

- Royalties are attractive to the governments because they ensure an upfront revenue stream as soon as production starts;
- As they attach to production or sales, they can be estimated with a reasonable degree of predictability;
- They are comparatively easy to calculate, collect, and monitor; and
- Royalties are a regressive form of taxation. High levels of royalties distort investment decisions and may favor uneconomic choices. To mitigate their regressiveness, some countries apply sliding scale royalties based on production levels or sales values, water depth or well depths, or, in rare cases, on project return on investment.

Effects on Investment Decisions

- Royalties have the tendency to distort the levels of recovery, although this effect is only relevant when the royalty is the most relevant part of the tax rent and when important difference in quality occur in crude oil or gas produced from a given contract area. In particular:
  - Unit royalties reduce the effective price by the same nominal amount each year. Since the NPV of the royalty decreases over time, investors will have an incentive to prefer future production over current production when future prices are expected to increase. In addition, a royalty imposed on the volume of production or sales may encourage the investor to delay the production or sale (subject to technical considerations) of the lighter, sweeter crudes or higher heating content gas if the discounted value of future prices is expected to increase; and
  - Ad valorem royalties reduce the discounted price of crude oil or gas by the same percentage in each year. Therefore, if the prices are expected to rise in real terms, investors would prefer increasing production (subject to technical considerations) in the present.
- As royalties are payable whether or not the project is profitable, they can constitute a major deterrent to investment.

Box A3.2: Taxes on Income: Ring-fencing, Corporate Income Tax, Resource Rent Tax

How do they work?

- *Ring-fencing* is an industry-specific feature. This refers to the delineation of taxable entities. While corporate income tax normally applies at the company level, in the petroleum sector, the taxable entity is often the contract area or the individual project. When ring-fencing applies at contract area or project level, income derived from one area/one project cannot be offset against losses from another area/project. Another type of ring-fencing separates upstream from downstream operations;

- Some countries include the petroleum industry within the standard corporate income tax regime, albeit they may use a higher tax rate to capture more rent. Under this method taxes are due only when annual revenues exceed some measure of costs and allowances. Therefore, the key elements of this tax form are the definition of taxable income and the rate applied to it. In defining the applicable rate, government should be mindful of the fact that home nation treatment of foreign earnings is ultimately of importance to investors. Rates that are too low merely transfer tax revenues to the treasury of the investors' home country. Therefore, if incentives are to be provided, adjustments in the definition of taxable income may prove more effective. In their traditional formulation, that is, a fixed tax rate, corporate taxes may not be neutral with respect to the ranking of projects;

- To ensure that the host government shares the upside if a project becomes very profitable, more and more countries have adopted progressive income tax rates. This is done by using stepped tax rates linked to parameters like the crude oil price, the volume of production, the sales value, and so on, and so forth. These are "add-on" to conventional proportional income tax;

- Resource rent taxes tie taxation more directly to the project's profitability. In its pure form, taxes are deferred until all expenditures have been recovered and the project has yielded a predefined target return. Then, a very high marginal tax is applied to all subsequent operating revenue. Basically, the project is granted a tax holiday compared to conventional tax regimes in anticipation of exceptionally high governmental returns over time. There are two main systems:

  - R-Factor-based systems are linked to the payback of an investment (that is, the ratio between cumulative after-tax receipts and cumulative expenditures – capex and opex); and

  - Rate of return-based systems are linked to the project's return on investment, and apply when a target rate of return-on-investment has been realized.

- In some countries, the investor's income tax is paid by the government out of its share of production.

Advantages and Disadvantages to Host Governments

- The objective of ring-fencing is to protect the level of current tax revenues and, to some extent, leveling the playing field by treating newcomers and existing investors equally. The disadvantage of ring-fencing is that it discourages exploration and investment activities;

- Because corporate income taxes are well defined in the country's tax code, their assessment, collection, and monitoring can be more easily accommodated within the country's existing systems thus lowering the government's administrative burden;

- Progressive income taxes tie the level of taxation to parameters that are linked to the level or activity or the price of crude oil or gas. This allows the host government to partake in the project's upsides when economic conditions are more favorable. This, however, entails a higher level of volatility in government's receipts that needs to be taken into consideration in macrofiscal policy design. The same consideration applies to any fiscal parameter linked to a sliding scale;

- The main advantage of a resource rent tax is its neutrality (at least in theory). The disadvantage is that it only provides income to the government when the target payback or rate of return is reached. This can be avoided by combining the resource rent tax with a royalty and/or a normal corporate income tax. The key issue then becomes that of defining an efficient target rate. This is a complex issue as it depends on the specific characteristics of the project, as well as exogenous conditions. Resource rent taxes are comparatively more difficult to assess and monitor. Therefore, the administrative cost of maintaining this system largely depends on the capacity of the host government's tax authority.

Effects on Investment Decisions

- Ring-fencing discourages exploration and investment activities. In cases, where complex integrated projects are considered (for example, the development of LNG plants financed by upstream investors, or the building of long cross-country pipelines) some host governments have granted the investors the possibility of offsetting losses among different activities. Other countries have preferred to maintain the integrity of their tax systems, and to provide similar level of incentives through the definition of transfer prices or through other incentives;

- The parameters normally used to determine the progressive rates of income tax are not necessarily fully correlated with the investors' return on investment. Hence, this type of corporate tax may not be neutral for investment decisions;

- Resource rent taxes are relatively neutral to investment decisions. This depends on how close the target rate is to the investor's discount rate, which, in turn, reflects the project risk and the investor's corporate profile; and

- In countries where the tax is paid by the government (or national oil company) on behalf of the contractor, consideration shall be given to structuring the tax in lieu so that they can be treated as if paid directly by the contractor for home country tax credit purposes. As the contractor is not affected by changes in tax rates, these types of agreements are generally very stable.

Box A3.3: Import and Export Duties, Value Added Tax, Surface Fees, Bonuses

How do they work?

- Import duties apply to all material and equipment imported in a country. In the past, these were used to provide protection from locally produced goods. Almost all countries have some sort of trade duty system, but, in the oil industry, import duties have had a limited use as fiscal tools (local content provisions have largely substituted the use of import duties to protect local industries). The majority of the countries provide exemptions from import duties on material and equipment destined for oil and gas operations. In some cases, the exemption is granted throughout the duration of the relevant PSA or concession agreement, in others, it is limited to the exploration and development phase. Some countries provide a blanket exemption; others limit the exemption to a specific list of materials and equipment. Exemptions for temporary import of equipment are the general practice in all producing countries;
- Because export duties distort the price of export and domestic supplies, they are normally not levied on oil and gas;
- Value Added Tax (VAT) is normally levied on a destination basis, that is, imports are taxed and exports are zero-rated. For this reason, oil and gas projects would normally be in a tax credit position. The majority of producing countries exempt or negate the effect of VAT on projects that export. This is done by providing some sort of credit, refund, exemption, drawbacks or deferrals at least during the initial phases of a project and/or to at least some type of purchases;
- Surface fees are generally paid annually on the basis of the aerial extent of the property under lease. Different fees normally apply for E&P acreage. Surface fees are set at a nominal amount. Their aim is to discourage investors from holding on to acreage without exploring it; and
- Bonuses are commonly paid by the investing company upon signature of an E&P agreement. In some cases, bonuses may be paid upon discovery, declaration of commerciality, start of production, commissioning of the facilities, and/or reaching target.

Advantages and Disadvantages to Host Governments

- For host governments, import duties provide a source of revenue from the very beginning of project operations. On the other hand, because of the nature of administering such duties, lower level government officers are often to classify the goods or delay its processing, thus, increasing the potential for corruption and bad practice. The use of list of exempted material and equipment often increases the customs authority's administrative burden. Because equipment and material originally imported for use in one project area may be used in other project areas, the grant of exemptions based on the destination to a particular project area often generates inefficiencies;
- Depending on the choice of system (whether outright exemption or some form of refund, credit, drawback or deferral) the administration of VAT for oil and gas projects can be quite complex. In particular, if the capacity is not in place to administer a refund-based system, a sector-specific exemption or an exemption limited to certain specialized inputs used exclusively in the oil and gas industry may be more efficient;

- Surface fees are easy to calculate, collect and monitor. They have the advantage of providing a source of revenue, albeit limited, during each phase of a project life. When a government upstream agency exists, surface fees are often collected by the agency that uses the revenue flow to cover its administrative costs;
- Bonuses are easy to administer and provide an early form of revenue. The maximum level of a bonus is very much dependent on the overall fiscal terms, the characteristics of the asset, the country political risk, and the risk profile of the targeted investors.
- Given the very substantial import needs during the exploration and development phase of a project, the payment of import duties on material and equipment directly impact project economics by reducing the NPV of the project and increasing its risk profile. For this reason, the existence of custom duties exemptions at least in the early stages of a project is of great value to investors;
- VAT has approximately the same effect on the investor's cash flow/return on investment as import duties. For this reasons fiscal systems that provide exemptions in respect to at least specialized inputs, are preferred by investors;
- Given their limited amount, surface fees do not present any particular disadvantage to investors; and
- High signature bonuses may discourage risk-adverse investors, especially when the political risk is perceived to be high, or when there is a high level of geological uncertainty. Commerciality bonuses are also sensitive as they increase the economic cut-off rate of a project.

Box A3.4: Government Participation

How does it work?

- Government's participation can take several forms. Participation may be acquired as "working interest," that is, on the same terms as might be available to other JV partners. This may occur from the outset of a project (very rare) or, more often, the government may reserve the right to back into the project at some stage (normally at field development or production). The right may be acquired on concessional terms. The most common way consists of acquiring a carried interest, that is, the government pays for its share out of future earnings of the project. In some countries, the government backs in without repaying the investor for the expenses borne and/or the risk taken during the exploration phase. The government may exercise its rights to participate in a project directly or through a SOE.

Advantages and Disadvantages to Host Governments

- Unless reasons other than the level of State revenue (increased sense of ownership, facilitate transfer of technology, increase control over field development decisions) motivate a host government to participate directly in a project, it is not at all demonstrated that government direct participation provides benefits not otherwise available from conventional taxes. As government participation represents a cost to investors, the higher the percentage participation, the lower other fiscal terms.

Advantages and Disadvantages to Investors

- Government participation on concessional terms reduces the cash flow and increases the risk profile of the investment. In addition, in case the cash calls on governments are paid out of production, the investors are left with the burden of raising the entire financing. In some cases, government direct participation in development activities may lead to suboptimal investment levels. Many investors regard the government participating option as a deterrent.

Box A3.5: Cost Recovery[269] Limit

How does it work?

- In many countries, PSAs provide for limits on the percentage of net crude oil production that can be used for cost recovery. After deduction of royalties, a percentage of the remaining revenue is used to recover costs. If costs exceed the cost recovery limit, the difference is carried forward for recovery in subsequent periods. Most PSAs allow for unlimited carry-forward. Not all costs are recoverable for the purpose of cost recovery. The relevant accounting rules are generally set in the contract.

Advantages and Disadvantages to Host Governments

- The cost recovery limit ensures that in each accounting period, the government will have a share in production. Cost recovery limits are less regressive than royalties. From an administrative standpoint, cost recovery limits are more difficult to monitor than royalties.

Advantages and Disadvantages to Investors

- In PSA that have a cost recovery limit, this would normally range between 40 percent and 60 percent (Johnston, 1994). Cost recovery limits have an effect on project's return on investment similar to a royalty. Cost recovery limits can be quite discouraging for the development of marginal fields. Concessionary systems normally do not have a cost recovery limit.

[269] *Cost recovery is a concept commonly applicable to contractual arrangements. Normally, cost recovery includes operating costs, expensed capital costs, depreciation and depletion allowance, interest on financing, investment uplift, abandonment cost fund, and unrecovered costs carried over from previous years. There are exceptions to the rule. For example, in Egypt and in the Syrian, Arab Republic excess cost oil goes directly to the government (some contracts provide for the excess cost oil to be split between the contractor and the government on different basis than those used for cost oil).*

Box A3.6: Profit Oil Split

How does it work?

- In PSAs, profit oil (or profit gas) is the revenue that remains after deduction of royalty and cost recovery. This corresponds to taxable income in concessionary systems and to the service fee in service contracts. The difference is linked to the ownership of hydrocarbons (at the delivery point in PSAs, at well head in concessionary systems, never in pure service contracts as all production belongs to the government). In most cases, the profit oil is split according to a sliding scale defined on the basis of agreed parameters (for example, average daily production, cumulative volume of production, crude oil prices, value of production, R-Factor, or rate of return).

Advantages and Disadvantages to Host Governments

- Sliding scale profit oil splits are flexible arrangements that allow the government to provide a suitable fiscal package to a particular project without changing the overall fiscal framework. On the other hand, fiscal parameters linked to sliding scales accentuate revenue volatility. There appears to be a preference among governments for sliding scale profit oil based on production rates. Although these are easier to calculate than sliding scale profit oil based on R-Factors or return on investment, they are insensitive to changes in the price of crude oil and natural gas.

Advantages and Disadvantages to Investors

- Sliding scale profit oil split, especially if linked to R-Factors or, even better, to the return on investment, are favorably considered by investors as they lower the project-specific risk by introducing flexibility in the fiscal package to suit the actual profitability of the particular project. Because of their flexibility, these types of arrangement are less likely to discourage the development of marginal fields than fix-parameter profit oil split.

Box A3.7: Foreign Exchange Controls, Environmental Taxes and Bonds, Other Performance Bonds and Local Content Obligations

How does it work?

- In cases where investors are required to surrender their foreign currency to the central bank at the time of export and repurchase the same at official rates to satisfy domestic project obligations, the spread between buying and selling rates (assuming no other restriction) increases the cost of doing business. Restrictive foreign currency regulations well head contribute to increase the perception of sovereign risk, thus impacting a project's NPV;
- The tax treatment of environmental obligations is of great importance to investors. The ability to deduct the cost of environmental compliance for tax calculation purposes lowers the costs of compliance;
- Performance bonds have been greatly standardized and do not present particular problems to investors. The cost of a bond will depend on the guarantees that the financial institution imposes on or is willing to accept from the investors, which, in turn, are a function of the country and project risks, of the investor's standing, and of the competitiveness of the chosen financial market;
- Many countries impose some form of local content obligations, and investors have developed procedures and systems to fulfill such requirements. Strict local content obligations normally increase the cost of operations and, in some cases, lower the company's efficiency. Ultimately, part of the cost is transferred to the host government through the sharing mechanism in contracts, and through taxation;
- There are no particular disadvantages to government that apply limited foreign exchange controls as controls over the convertibility of currencies have become less dominant than in the past. To satisfy statistical needs, companies are normally asked to report to the central bank all currency movements. To guarantee domestic expenditure obligations performance bonds and similar guarantees are equally effective and less costly to investors. In countries that apply strict foreign exchange regulations, petroleum contracts normally grant exemptions to oil and gas companies. This is because oil and gas is normally sold in the international markets, and the proceeds of sale are often pledged as security for repayment of project loans;
- Direct taxation of environmental damages may be conceptually good for correcting divergence between private and social costs. However, it is quite complex to implement. In defining the tax treatment of environmental conservation and remediation, policy makers need to avoid penalizing responsible operators. This is generally done by allowing the amortization of environmental mitigation structures and equipment over their useful life, and the deduction of current environmental expenses for tax calculation purposes;
- Under an ideal bonding regime, the financial risk is shifted from the government to the investor. In case of default, funds necessary to complete contractual obligations would be promptly available avoiding complicated and costly legal processes;
- Local content obligations allow the government to achieve a diversity of policy objectives, from transfer of technology and know how to the strengthening of local industries and the creation of local employment. However, governments should be mindful of the need to avoid increasing inflationary pressure by allowing or imposing excessive salary scales or promoting excessive mark-ups for local goods and services. In addition, given the international nature of the oil business and the fact that oil companies generally operate in more than one country, when deciding the level of secondments, consideration should be given to the absorption capacity of the investor's organization (that is, small companies may not be able to accommodate a large number of government trainees).

Advantages and Disadvantages to Investors

- In cases where investors are required to surrender their foreign currency to the central bank at the time of export and repurchase the same at official rates to satisfy domestic project obligations, the spread between buying and selling rates (assuming no other restriction) increases the cost of doing business. Restrictive foreign currency regulations contribute to increase the perception of sovereign risk, thus, impacting a project's NPV;

- The tax treatment of environmental obligations is of great importance to investors. The ability to deduct the cost of environmental compliance for tax calculation purposes lowers the costs of compliance;

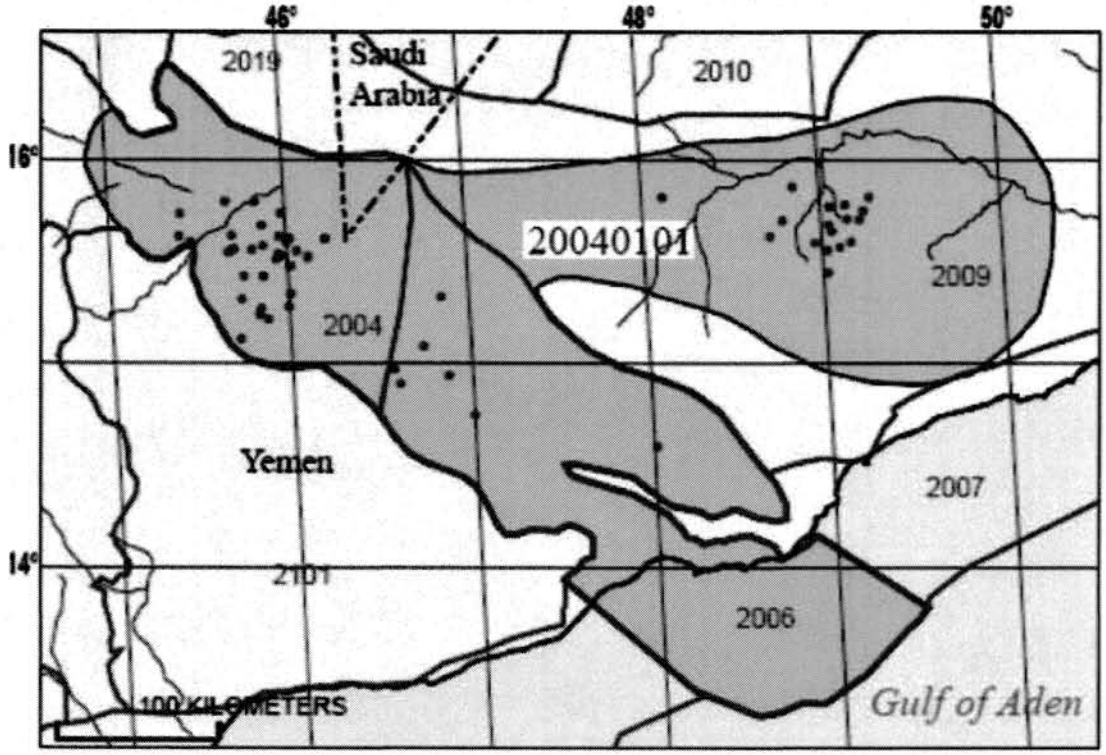
- Performance bonds have been greatly standardized and do not present particular problems to investors. The cost of a bond will depend on the guarantees that the financial institution imposes on or is willing to accept from the investors, which, in turn, are a function of the country and project risks, of the investor's standing and of the competitiveness of the chosen financial market; and

- Many countries impose some form of local content obligations, and investors have developed procedures and systems to fulfill such requirements. Strict local content obligations normally increase the cost of operations and, in some cases, lower the company's efficiency. Ultimately, part of the cost is transferred to the host government through the sharing mechanism in contracts and through taxation.

Annex 4
Undiscovered Fields

Area covered by the survey:

Ma. Rib Al Jawf, Shabwah and Masila Basins



Source: World Petroleum Assessment 2000, USGS.

Average Ratios for Undiscovered Fields, to Assess Coproducts

(uncertainty of fixed but unknown values)

Oil Fields	*Minimum*	*Median*	*Maximum*
Gas/Oil Ratio (cfg/bo)	2000	4000	6000
NGL/Gas Ratio (bngl/mmcfg)	30	60	90
Gas Fields:	Minimum	Median	Maximum
Liquids/Gas Ratio (bngl/mmcfg)	22	44	66
Oil/Gas Ratio (bo/mmcfg)			

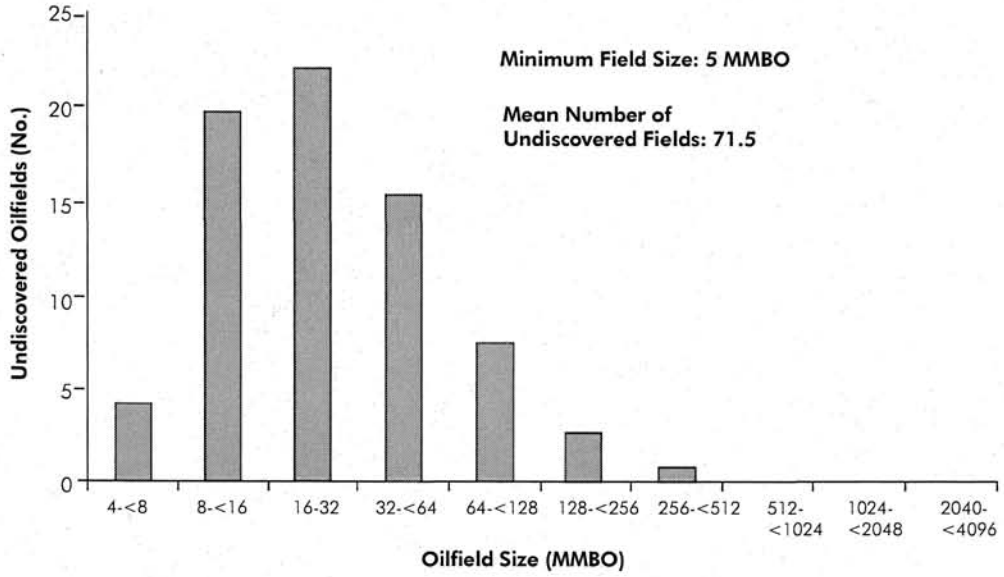
Selected Ancillary Data for Undiscovered Fields

(variations in the properties of undiscovered fields)

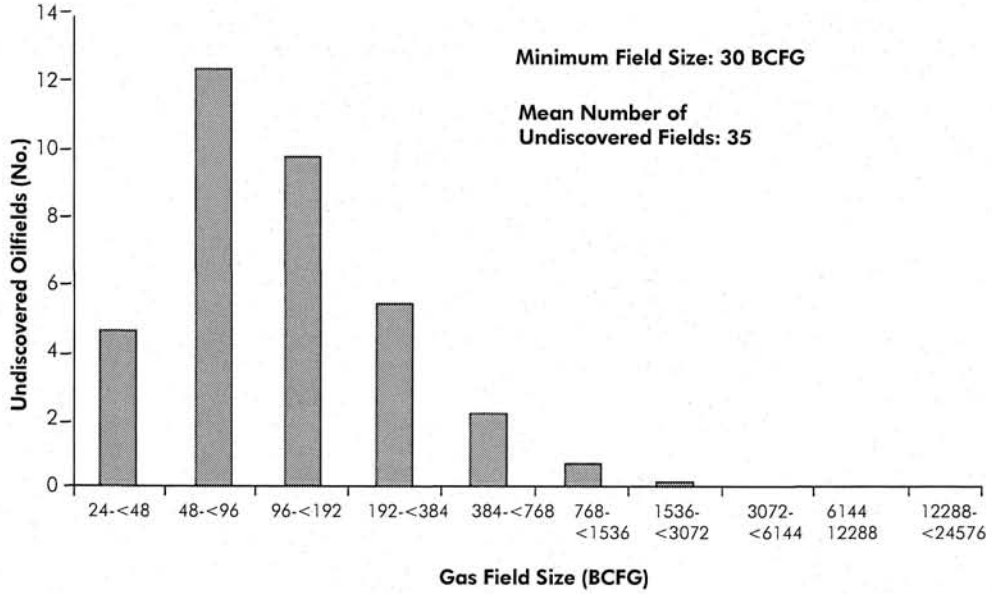
Oilfields	*Minimum*	*Median*	*Maximum*
API Gravity (degrees)	19	36	45
Sulfur Content of Oil %	0.1	0.25	0.54
Drilling Depth (m)	750	2,500	4,000
Depth (m) of Water (if applicable)	0	0	100
V-12, 19, 2.3, 25, 26 V-2-26 ppm Ni-6, 7, 1.3, 5.0, 11 Ni-6-11 ppm			
Gas Fields	*Minimum*	*Median*	*Maximum*
Inert Gas Content (%)			
Co_2 Content (%)			
Hydrogen-Sulfide Content (%)			
Drilling Depth (m)	750	3,000	5,000
Depth (m) of Water (if applicable)	0	0	100

Source: World Petroleum Assessment 2000, USGS.

Ma'Rib-Al Jawf/Shabwah/Masila, AU 20040101 Undiscovered Field-size Distribution



Ma'Rib-Al Jawf/Shabwah/Masila, AU 20040101 Undiscovered Field-size Distribution



Source: World Petroleum Assessment 2000, USGS.

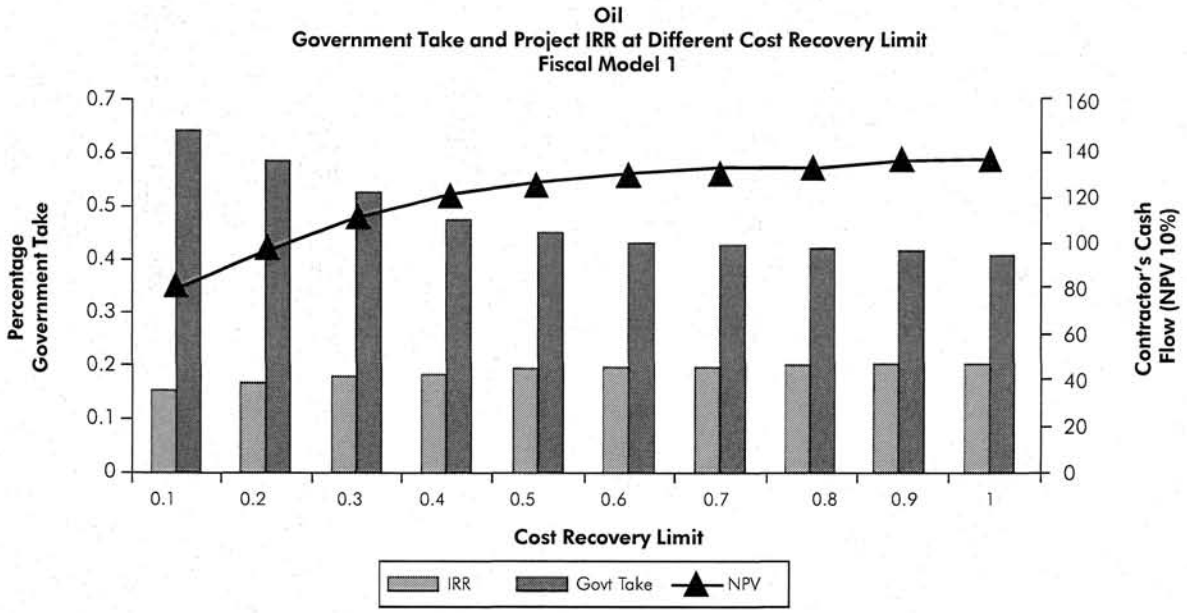
Annex 5
Fiscal Models Simulation

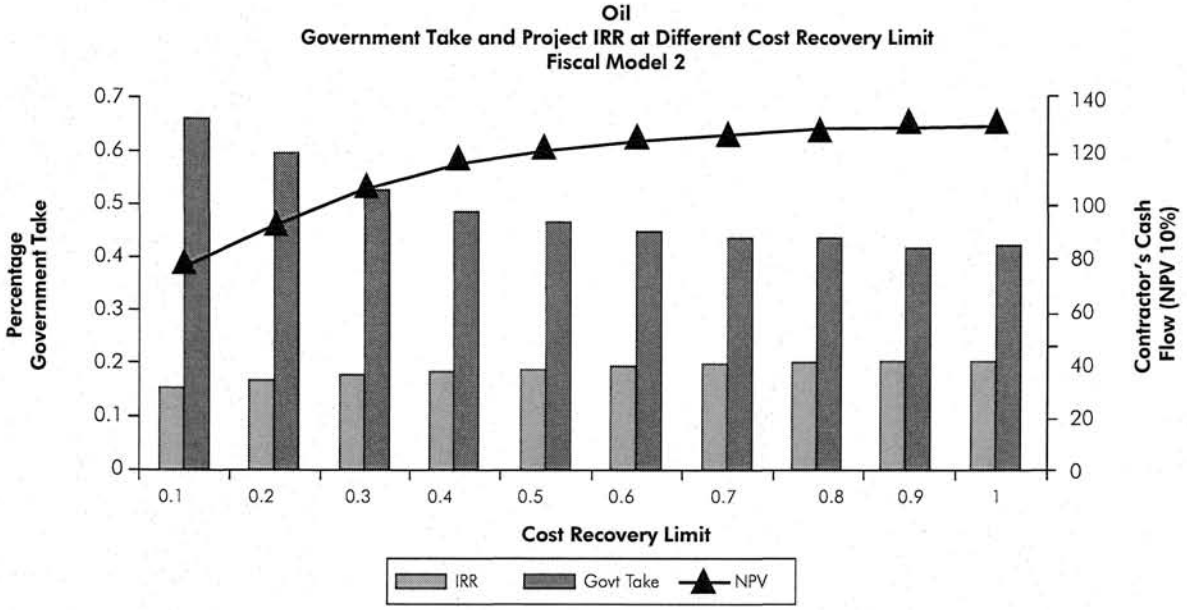
Table A5.1: Oil Project

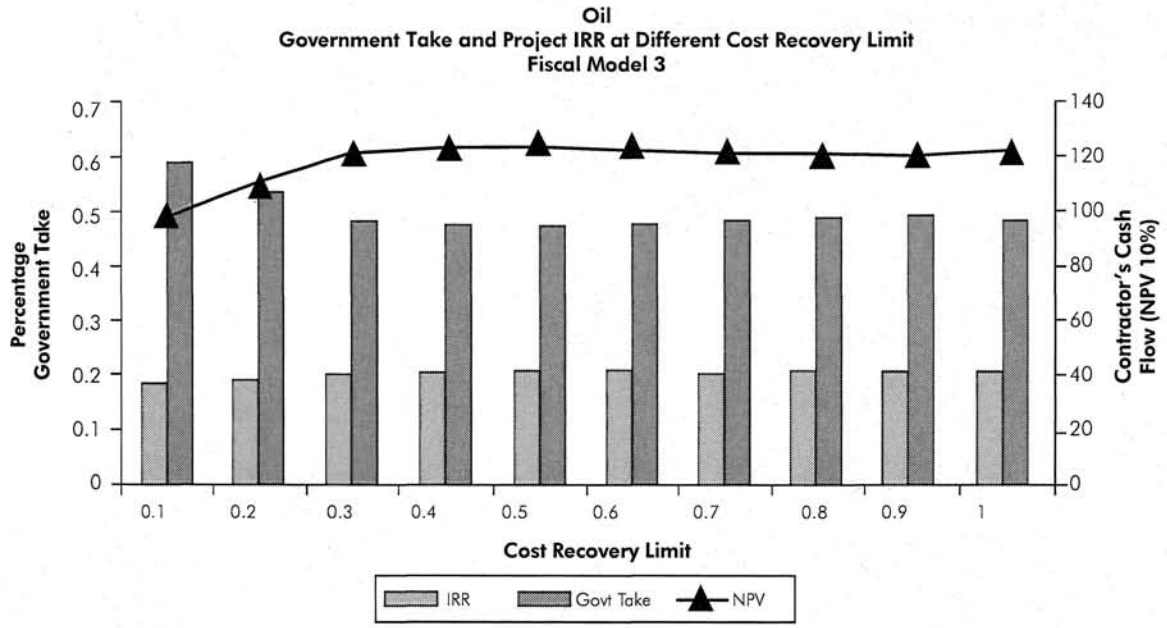
			Fiscal Model No. 1/Oil					Fiscal Model No. 2/Oil					Fiscal Model No. 3/Oil					Fiscal Model No. 4/Oil				
Production Sharing based on:			Daily Production					Cumulative Production					R-Factor					RoR				
OIL				Investor's NPV ($ Million)		IRR	Govt. Take (undisc)		Investor's NPV ($ Million)		IRR	Govt. Take		Investor's NPV ($ Million)		IRR	Govt. Take		Investor's NPV ($ Million)		IRR	Govt. (Take undisc)
			10.0%	12.5%	15.0%			10.0%	12.5%	15.0%		(@ 10%)	10.0%	12.5%	15.0%		(@ 10%)	10.0%	12.5%	15.0%		
Production (MBO)	59	Investor's	119.7	67.4	31.7	18.4%	47.5%	116.5	65.6	30.6	18.3%	48.9%	121.3	74.5	41.5	20.1%	46.8%	128.4	78.7	44.0	20.3%	43.7%
Price ($/Bbl)	30																					
Capex ($ Million)	254	NOC's	–	–	–			#REF!	#REF!	#REF!			–	–	–			–	–	–		
Opex ($/Bbl)	5.31																					
Price limit ($/Bbl)			20.43	23.06	25.87			20.56	23.27	25.97			18.70	21.26	23.9			18.45	20.86	23.55		
Sensitivities:																						
Production		+20%	177.3	112.7	68.2	22.2%	42.6%	168.3	107.3	64.9	22.1%	45.5%	166.9	112.8	73.9	24.3%	46.0%	175.9	117.2	75.7	24.1%	43.1%
		-20%	61.6	21.6	(5.1)	14.4%	58.0%	61.6	21.6	(5.1)	14.4%	58.0%	73.4	34.6	7.9	16.0%	50.0%	80.3	39.0	10.7	16.3%	45.3%
Price		+20%	190.6	123.4	76.8	23.1%	41.4%	186.7	121.1	75.5	23.1%	42.7%	171.0	116.5	77.3	24.8%	47.5%	185.0	124.6	81.9	24.9%	43.2%
		-20%	46.2	9.5	(14.8)	13.4%	64.5%	44.2	8.3	(15.5)	13.3%	66.1%	63.7	26.3	0.8	15.1%	51.1%	70.0	30.4	3.4	15.4%	46.2%
Capex		+20%	86.0	35.5	1.7	15.2%	55.3%	82.8	33.7	0.6	15.1%	57.0%	98.2	50.1	16.7	16.7%	49.0%	105.9	55.0	20.0	17.0%	45.0%
		-20%	152.9	98.8	61.4	23.1%	42.0%	149.7	97.0	60.4	23.0%	43.2%	140.1	95.5	63.4	25.0%	46.8%	149.3	100.6	66.2	24.9%	43.3%
Opex		+20%	105.6	56.1	22.6	17.4%	50.0%	102.5	54.4	21.6	17.4%	51.5%	113.8	67.5	35.1	19.3%	46.2%	117.0	69.3	36.2	19.3%	44.6%
		-20%	133.5	78.4	40.6	19.4%	45.4%	130.2	76.5	39.5	19.3%	46.8%	127.3	80.3	46.8	20.9%	47.9%	139.2	87.6	51.5	21.2%	43.1%
			Corp.Tax	In Lieu	C/R Limit		40%	Corp. Tax	In Lieu	C/R Limit		40%	Corp. Tax	In Lieu	C/R Limit		40%	Corp Tax	In Lieu	C/R Limit		40%
			Expl.Tax	3%	NOC		0.0%	Expl. Tax	3%	NOC	NOC	0%	Expl. Tax 0%	3%	Royalty NOC		3.0% 0%	Expl.Tax	3%	Royalty		3.0%
					P/O Split		Royalty			P/O Split		Royalty			P/O Split				P/G Split			
				0 < D/Pro	25	30%	3%		0 < C/Pro <	50	30%	3%		R/F <	1		10%		RoR	< 5%	10%	
				25 < D/Pro	50	45%	5%		50 < C/Pro<	150	45%	5%		1 < R/F <	1.5		30%		5% < RoR <	15%	30%	
				50 < D/Pro	75	60%	6%		150 < C/Pro <	250	60%	6%		1.5 < R/F<	2		45%		15% < RoR	< 25%	45%	
				75 < D/Pro	100	75%	8%		250 < C/Pro <	300	75%	8%		2 < R/F<	2.5		60%		25% < RoR <	35%	60%	
				100 < D/Pro	90%	10%			300 < C/Pro	90%	10%			2.5 < R/F<	3		75%		35% < RoR<	45%	75%	
														3 < R/F			90%		45% < RoR		90%	
		Stress Test	NPV (10)		(48.5) NPV (15)		(82.2)	NPV (10)	(48.5) NPV (15)		(82.2)	NPV (10)		(23.6) NPV (15)			(64.4)	NPV (10)	(19.3) NPV (15)			(62.5)

Note: Exploration Capex includes associated gas.

Figure A5.1: Government Take and Project's IRR at Different C/R levels – Oil






Oil
Government Take and Project IRR at Different Cost Recovery Limit
Fiscal Model 3
Percentage Government Take
Contractor's Cash Flow (NPV 10%)
0.7
0.6
0.5
0.4
0.3
0.2
0.1
0
140
120
100
80
60
40
20
0
0.1
0.2
0.3
0.4
0.5
0.6
0.7
0.8
0.9
1
Cost Recovery Limit
IRR
Govt Take
NPV

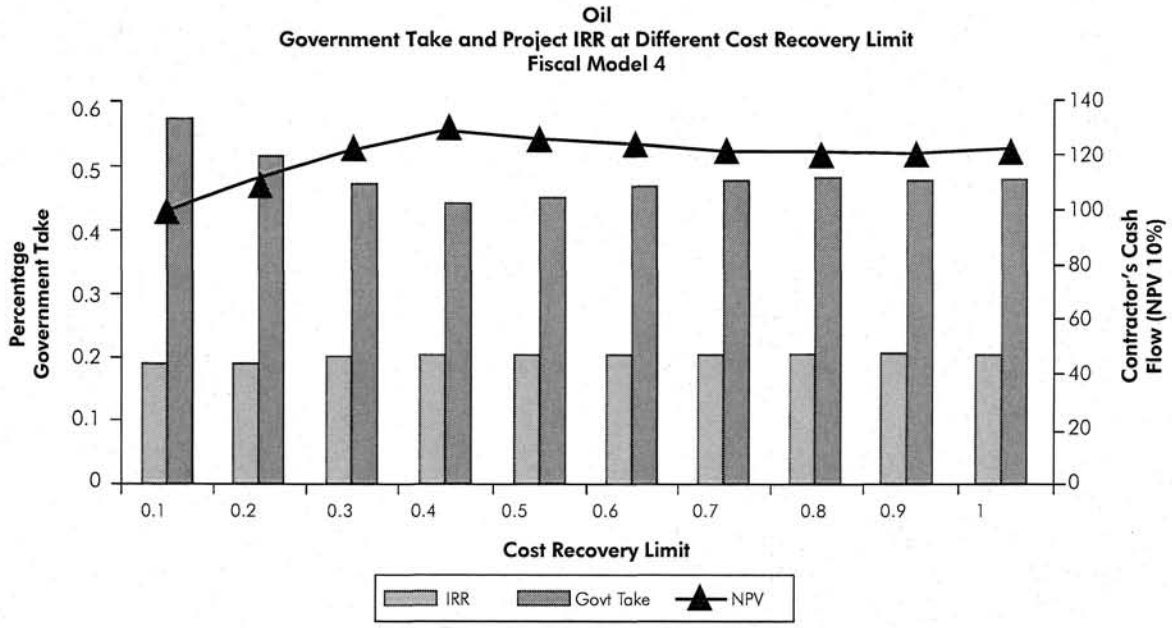
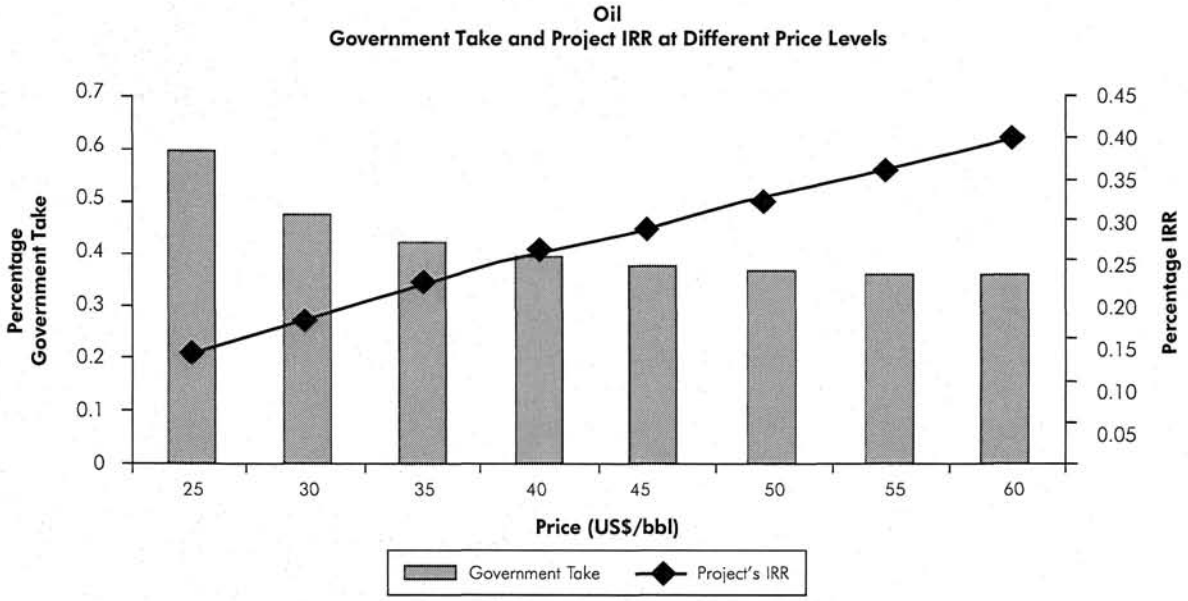
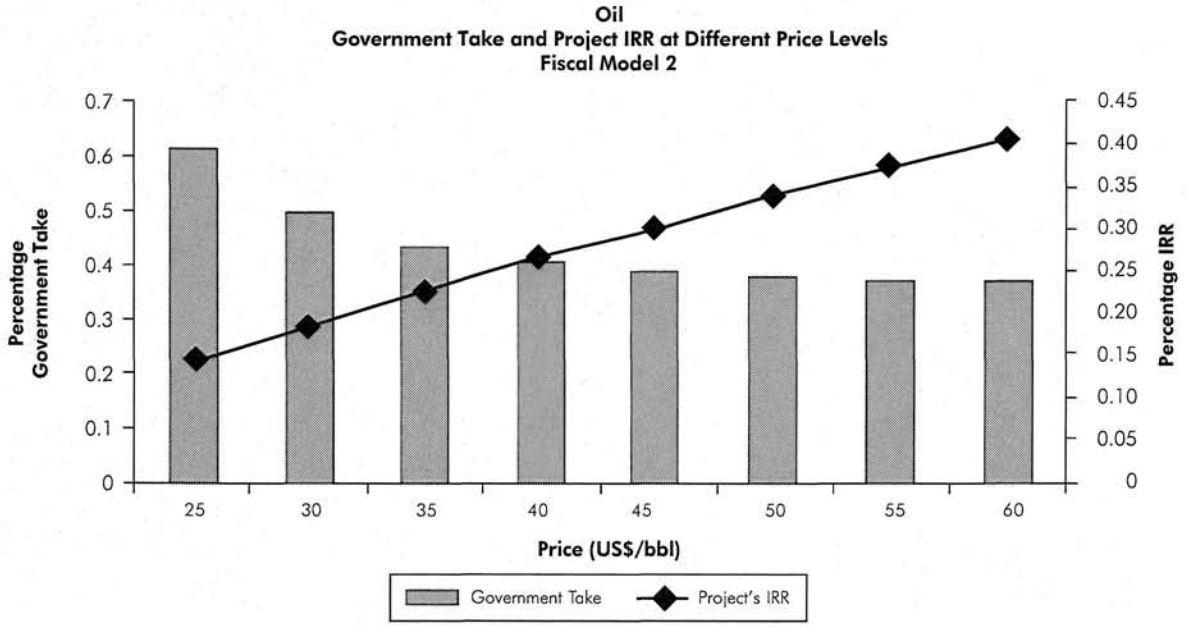
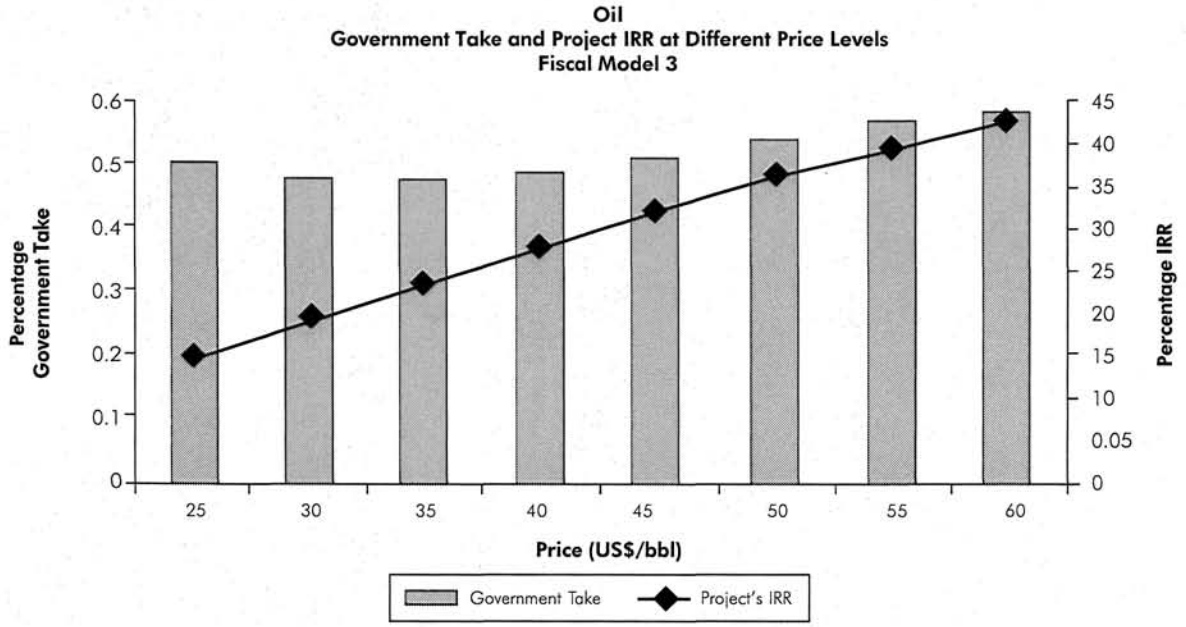

Oil
Government Take and Project IRR at Different Cost Recovery Limit
Fiscal Model 4
Percentage Government Take
Contractor's Cash Flow (NPV 10%)
0.6
0.5
0.4
0.3
0.2
0.1
0
140
120
100
80
60
40
20
0
0.1
0.2
0.3
0.4
0.5
0.6
0.7
0.8
0.9
1
Cost Recovery Limit
IRR
Govt Take
NPV

Figure A5.2: Government Take and Project's IRR at Different Price Levels – Oil






Oil
Government Take and Project IRR at Different Price Levels
Fiscal Model 3
Percentage Government Take
0.6
0.5
0.4
0.3
0.2
0.1
0
Percentage IRR
45
40
35
30
25
20
15
10
0.05
0
25
30
35
40
45
50
55
60
Price (US$/bbl)
Government Take
Project's IRR

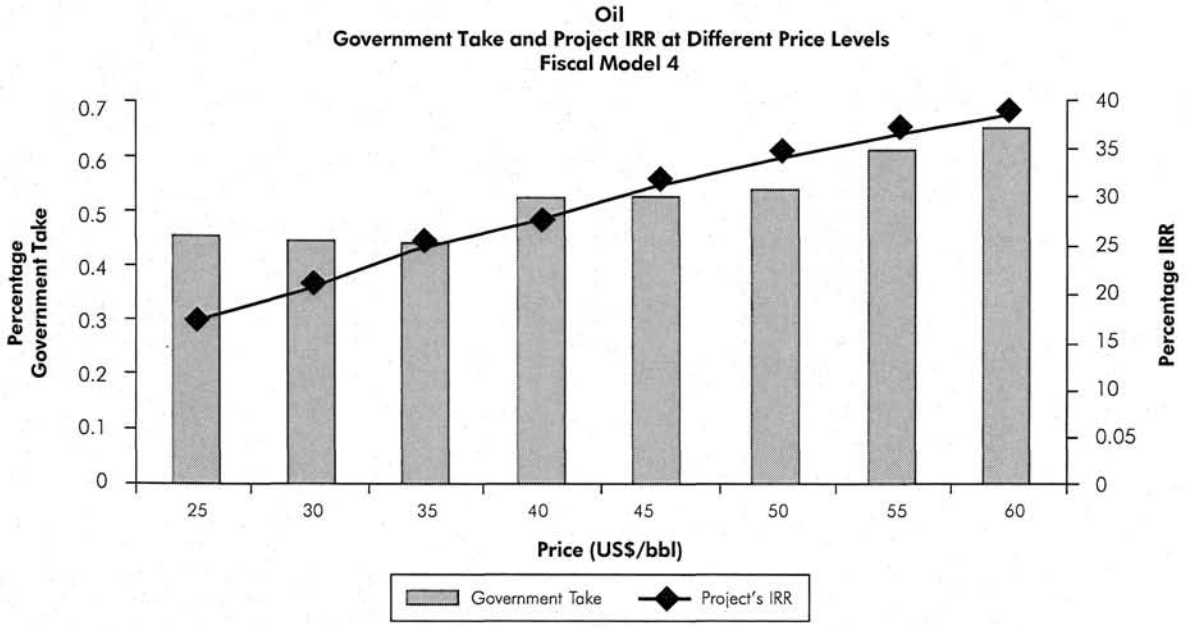
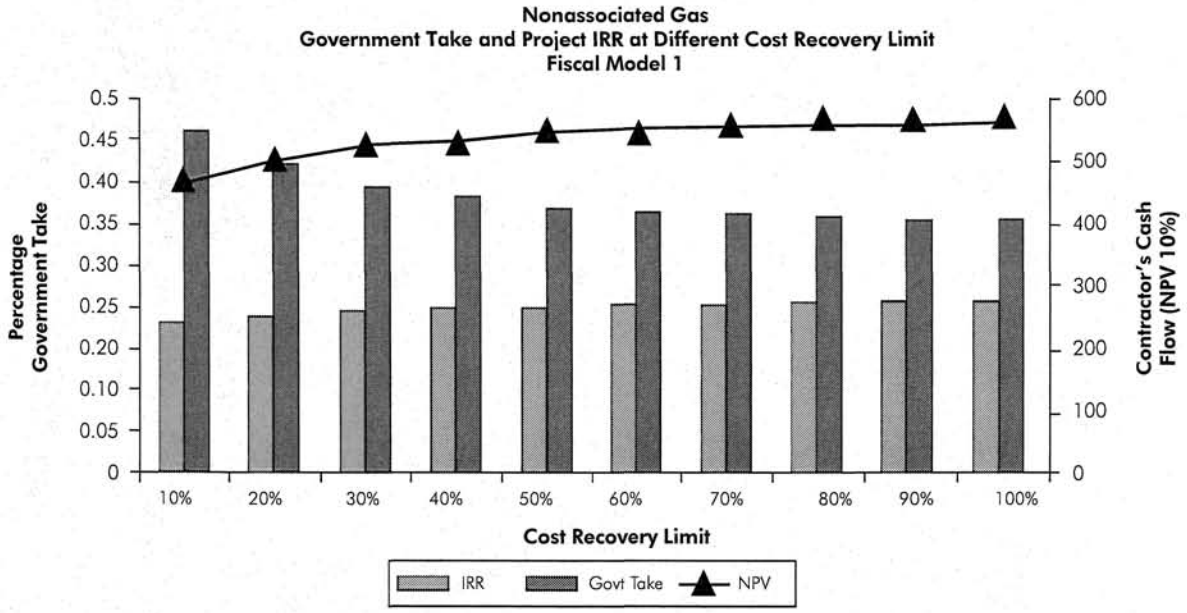

Oil
Government Take and Project IRR at Different Price Levels
Fiscal Model 4
Percentage Government Take
0.7
0.6
0.5
0.4
0.3
0.2
0.1
0
Percentage IRR
40
35
30
25
20
15
10
0.05
0
25
30
35
40
45
50
55
60
Price (US$/bbl)
Government Take
Project's IRR

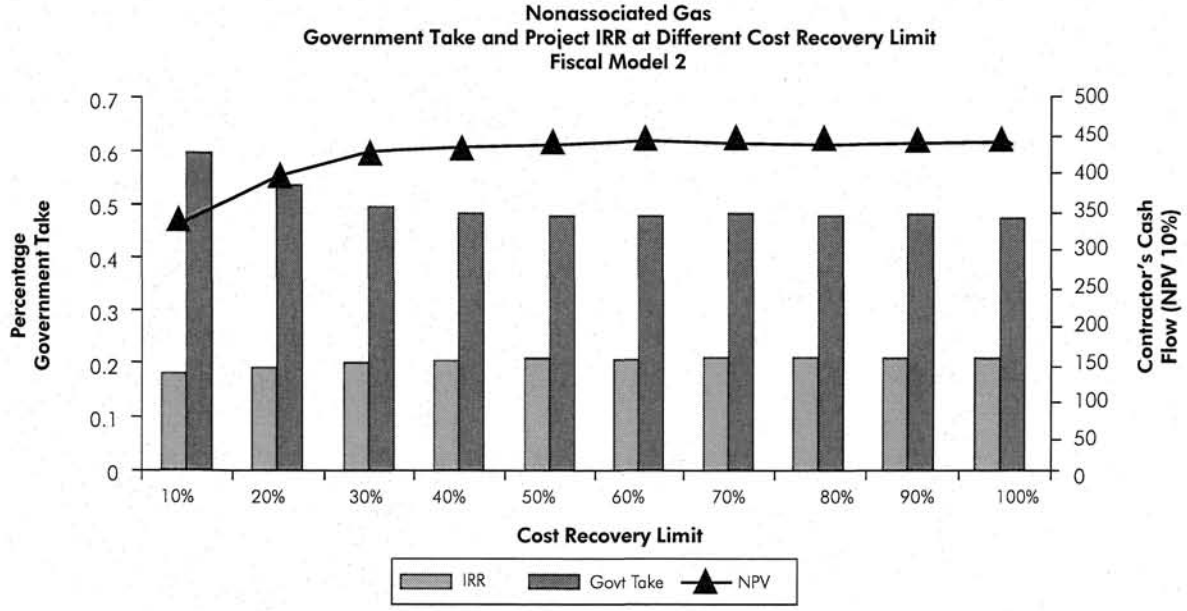
Table A5.2: Associated Gas Project

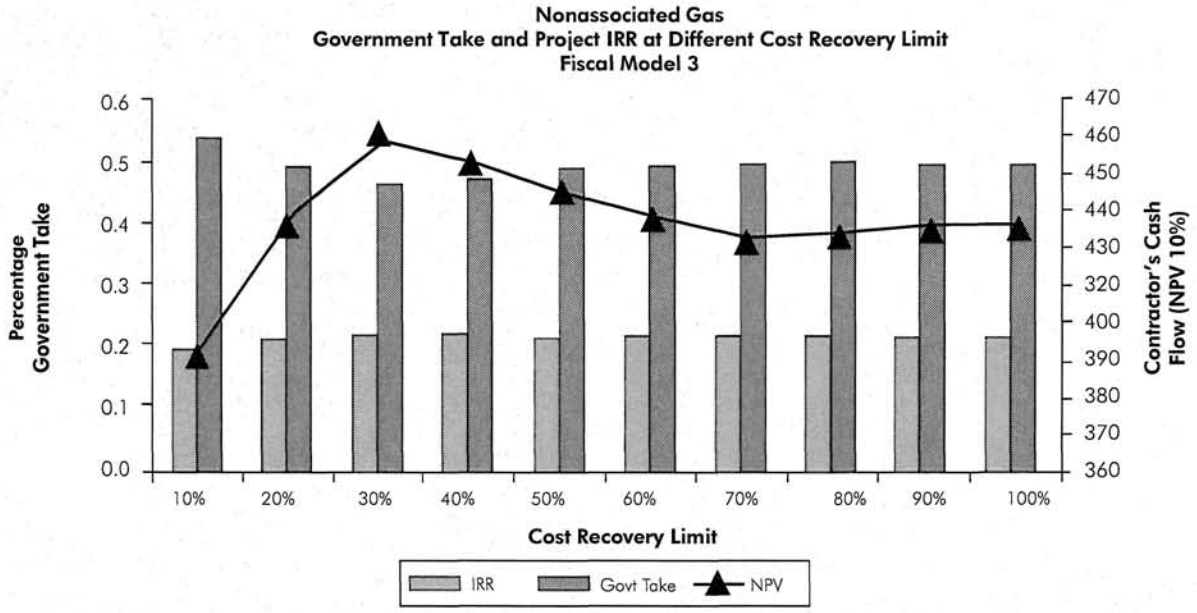
			Fiscal Model No. 1/Oil					Fiscal Model No. 2/Oil					Fiscal Model No. 3/Oil					Fiscal Model No. 4/Oil				
Production Sharing based on:			Daily Production					Cumulative Production					R-Factor					RoR				
	OIL		Investor's NPV ($ Million)			IRR	Govt. Take (undisc)	Investor's NPV ($ Million)			IRR	Govt. Take	Investor's NPV ($ Million)			IRR	Govt. Take	Investor's NPV ($ Million)			IRR	Govt. (Take undisc)
			10.0%	12.5%	15.0%			10.0%	12.5%	15.0%		(@ 10%)	10.0%	12.5%	15.0%		(@ 10%)	10.0%	12.5%	15.0%		
Production (MMCF)	207	Investor's	79	46	22	18.5%	42.1%	78.7	45.8	22.3	18.5%	42.1%	81.0	49.0	27.1	19.6%	40.4%	82.5	50.7	27.6	19.7	%	39.4%
Price ($/MMCF)	4.5																						
Capex ($ Million)	300	NOC's	–	–	–			–	–	–			–	–	–		–	–	–				
Opex ($/MMCF)	0.20																						
Price Limit ($/MMCF)			3.21	3.56	3.94			3.21	3.56	3.94			3.03	3.36	3.74			3.00	3.34	3.71		
	Sensitivities:																					
	Prod.	+20%	128.3	86.3	55.7	23.6%	36.4%	128.3	86.3	55.7	23.6%	36.4%	120.2	83.2	55.6	24.6%	40.4%	120.4	82.5	54.5	24.3%	40.3%
		-20%	27.7	4.1	(12.2)	13.0%	60.5%	27.7	4.1	(12.2)	13.0%	60.5%	37.2	41.6	11.5	14.3%	47.0%	40.2	14.9	(2.9)	14.5%	42.7%
	Price	+20%	130.7	88.3	57.3	23.9%	36.2%	130.7	88.3	57.3	23.9%	36.2%	118.0	81.5	54.3	24.5%	42.4%	122.3	84.1	55.9	24.5%	40.3%
		-20%	25.0	1.9	(14.0)	12.7%	62.8%	25.0	1.9	(14.0)	12.7%	62.8%	34.7	10.8	(6.0)	14.0%	48.3%	37.5	12.7	(4.7)	14.2%	44.1%
	Capex	+20%	43.6	13.4	(7.6)	14.0%	55.2%	43.6	13.4	(7.6)	14.0%	55.2%	55.0	24.1	2.1	15.3%	43.5%	57.1	25.5	3.2	15.4%	41.4%
		-20%	112.5	77.1	51.2	24.9%	35.5%	112.5	77.1	51.2	24.9%	35.5%	101.7	71.3	48.5	25.6%	41.7%	101.6	71.0	48.2	25.5%	41.8%
	Opex	+20%	76.2	43.8	20.6	18.2%	42.7%	76.2	43.8	20.6	18.2%	42.7%	79.3	48.4	25.8	19.4%	40.4%	80.3	49.0	26.2	19.4%	39.6%
		-20%	81.1	47.8	24.0	18.8%	41.6%	81.1	47.8	24.0	18.8%	41.6%	83.0	51.5	28.5	19.8%	40.3%	84.4	52.4	29.1	19.9%	39.3%
			Corp.Tax	In Lieu	C/R Limit		50%		Corp. Tax	In Lieu	C/R Limit	50%		Corp. Tax	In Lieu	C/R Limit	50%		Corp Tax	In Lieu	C/R Limit	50%
			Expl.Tax	3%	NOC		0.0%		Expl. Tax	3%	NOC	0%		Expl. Tax	3%	Royalty NOC	3.0% 0%		Expl.Tax	3%	Royalty NOC	3.0% 0%
					P/O Split		Royalty			P/O Split		Royalty			P/O Split				P/G Split			
				0 < D/Pro <	250	25%	3%		0 < C/Pro <	280	25%		3%	R/F <	1		10%		RoR <	0.05	10%	
				250 < D/Pro <	500	35%	5%		280 < C/Pro <	850	35%		5%	1< R/F <	1.5		30%		5 < RoR <	15	30%	
				500 < D/Pro <	750	50%	6%		850 < C/Pro <	1400	50%		6%	1.5 < R/F <	2		45%		15< RoR <	25	45%	
				750 < D/Pro <	1000	65%	8%		1400 < C/Pro <	1700	65%		8%	2< R/F <	2.5		60%		25< RoR <	35	60%	
				1000 < D/Pro		85%	10%		1700 < C/Pro		85%		10%	2.5< R/F <	3		75%		35< RoR <	45	75%	
										3 < R/F			90%	45 < RoR			90%					
		Stress Test	NPV (10)	(59.2)	NPV (15)	(76.1)	NPV (10)	(59.2)	NPV (15)		(76.1)	NPV (10)		(45.5)	NPV (15)		(66.7)	NPV (10)		(43.3)	NPV (15)	(65.7)

Note: Exploration capex is recovered as part of the cost recovery oil.

Figure A5.3: Government Take and Project's IRR at Different C/R Levels – Associated Gas






Nonassociated Gas
Government Take and Project IRR at Different Cost Recovery Limit
Fiscal Model 3
Percentage Government Take
Contractor's Cash Flow (NPV 10%)
0.0
0.1
0.2
0.3
0.4
0.5
0.6
360
370
380
390
400
320
430
440
450
460
470
10%
20%
30%
40%
50%
60%
70%
80%
90%
100%
Cost Recovery Limit
IRR
Govt Take
NPV

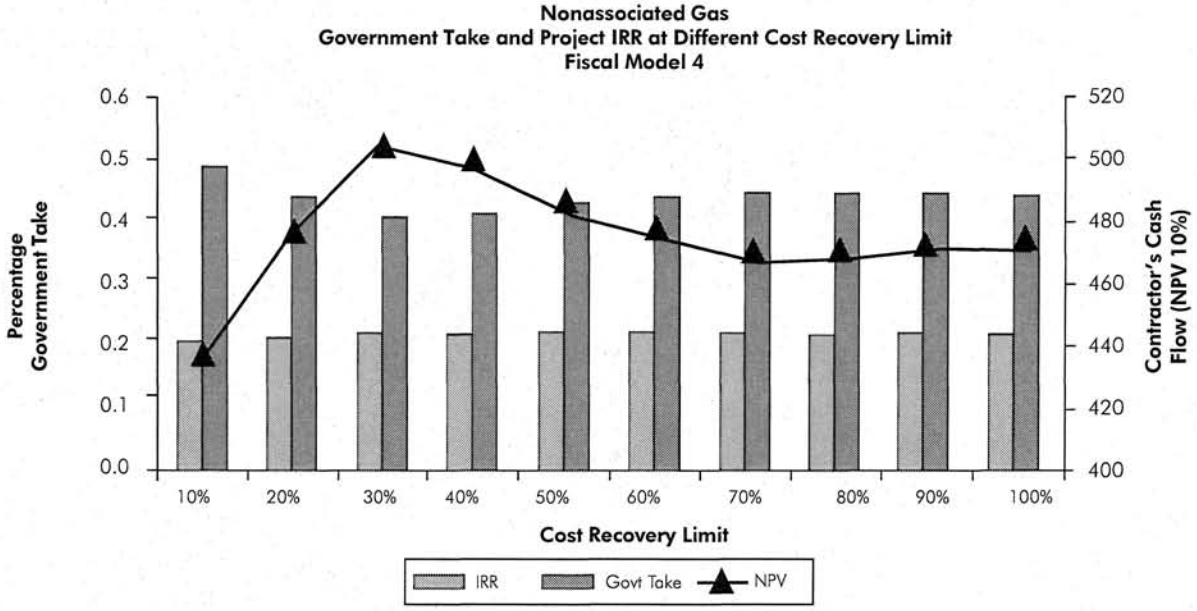
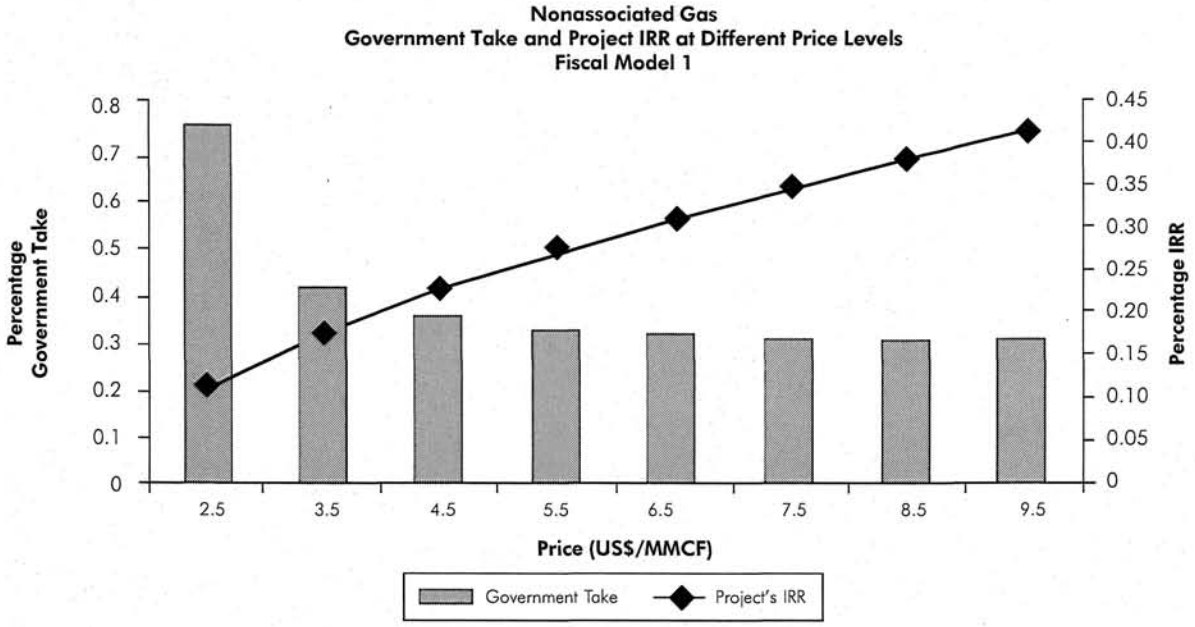
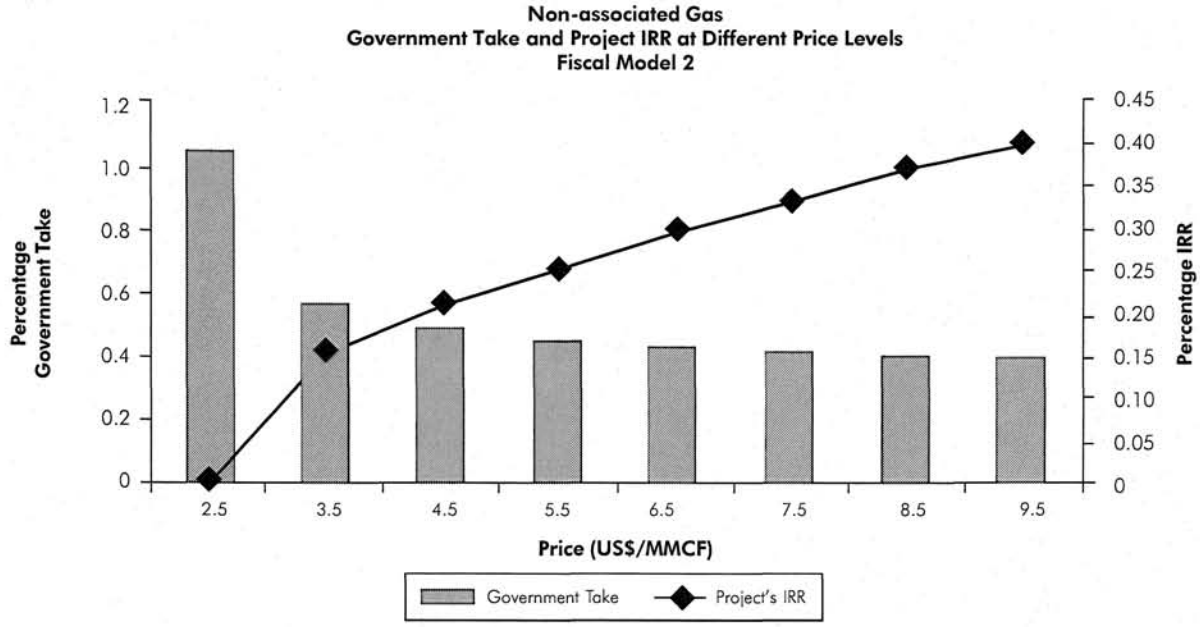
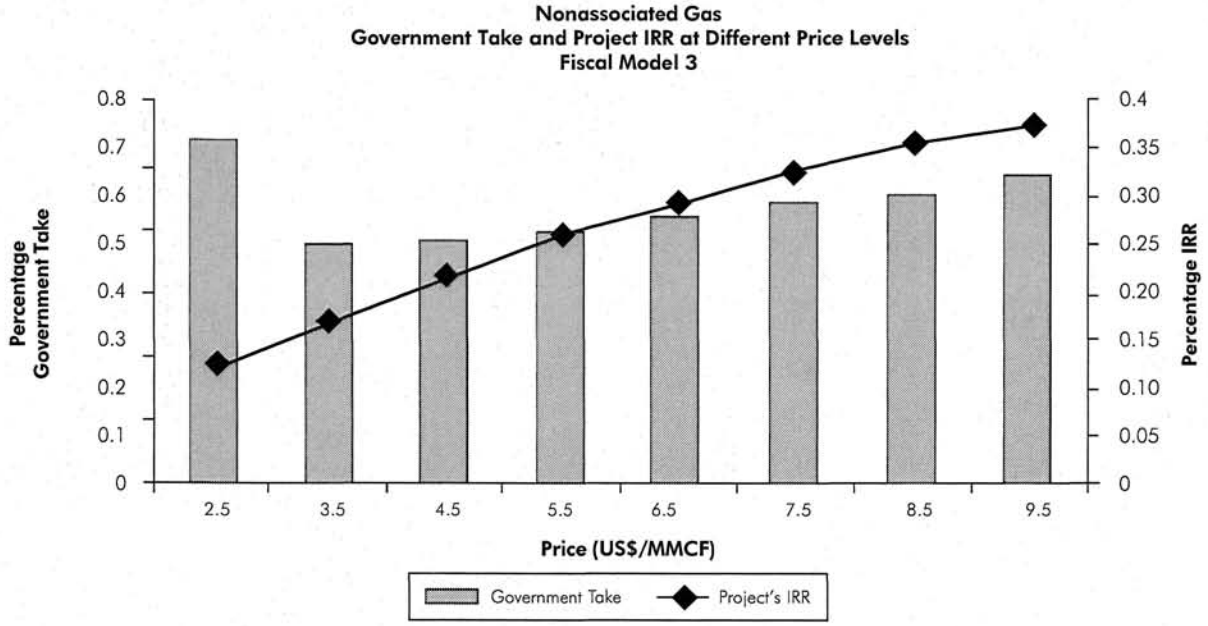
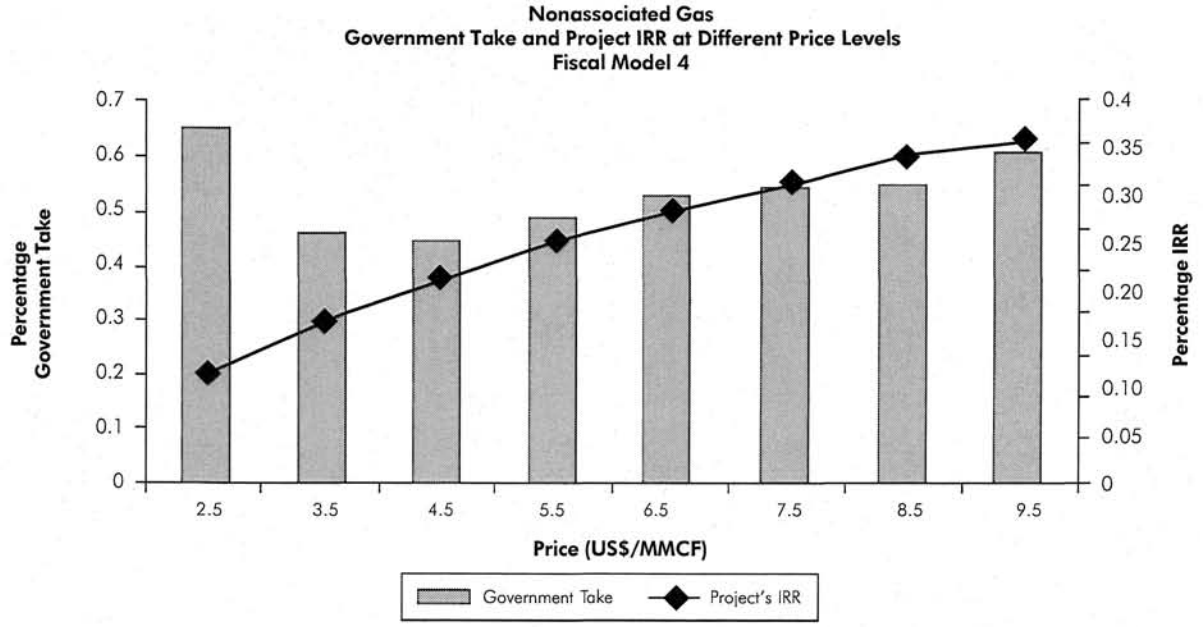

Nonassociated Gas
Government Take and Project IRR at Different Cost Recovery Limit
Fiscal Model 4
Percentage Government Take
Contractor's Cash Flow (NPV 10%)
0.0
0.1
0.2
0.3
0.4
0.5
0.6
400
420
440
460
480
500
520
10%
20%
30%
40%
50%
60%
70%
80%
90%
100%
Cost Recovery Limit
IRR
Govt Take
NPV

Figure A5.4: Government Take and Project's IRR at Different Price Levels – Associated Gas







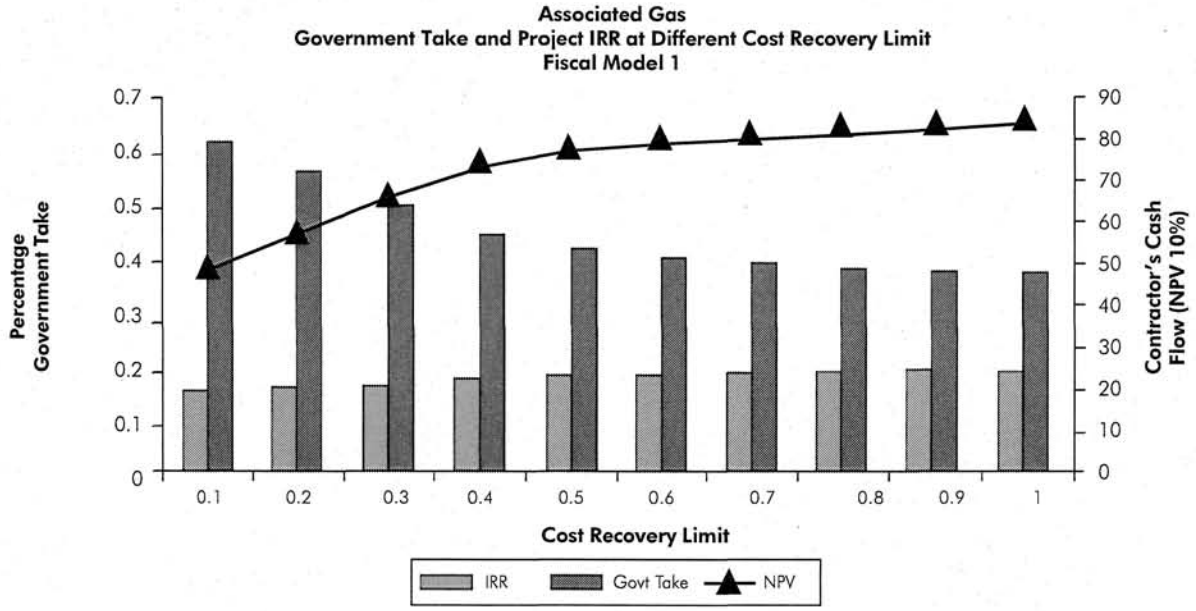


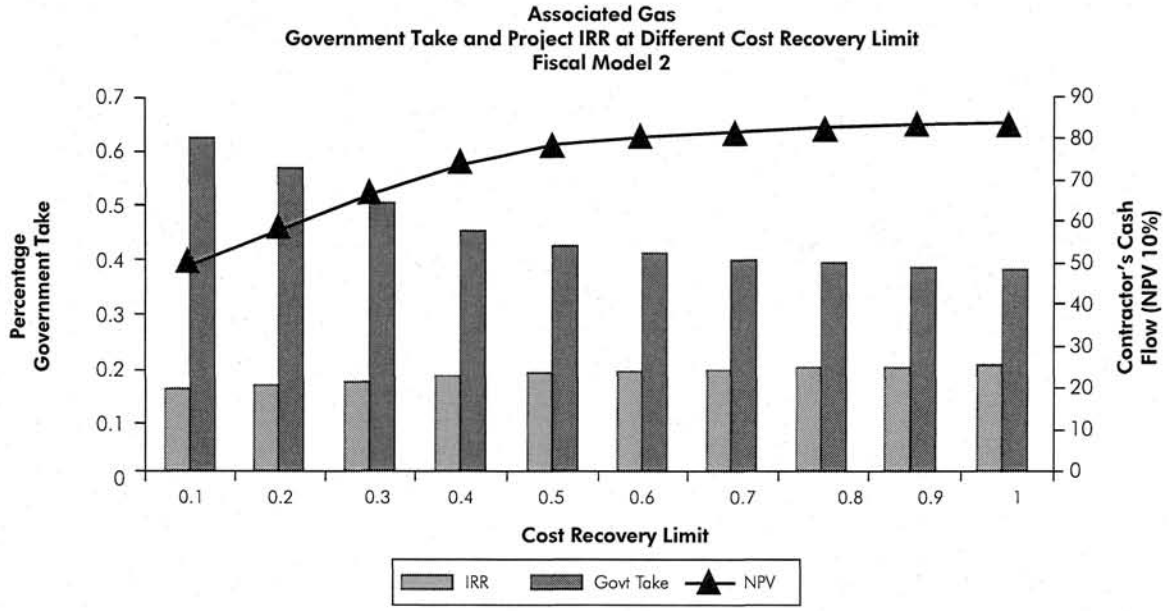
Note: The combined effect of royalties, cost recovery limit and exploration tax may produce a Government Take above 100 percent. In these cases, the graphs show a Government Take of 101 percent.

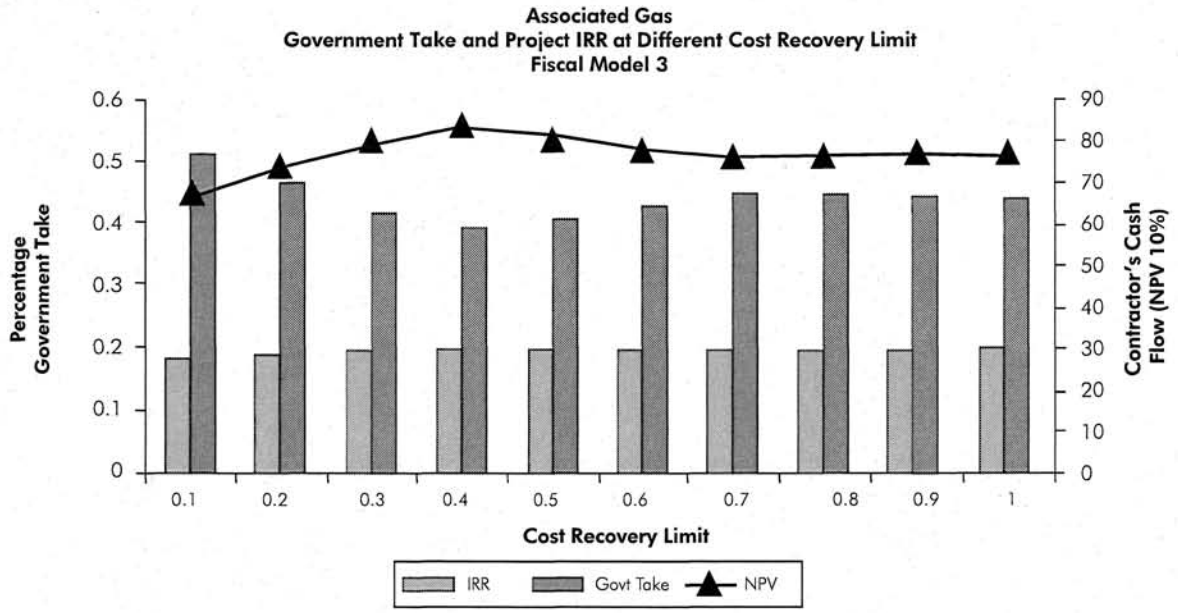
Table A5.3: Nonassociated Gas Project

			Fiscal Model No. 1/Oil					Fiscal Model No. 2/Oil					Fiscal Model No. 3/Oil					Fiscal Model No. 4/Oil				
Production-sharing based on:			**Daily Production**					**Cumulative Production**					**R-Factor**					**Rate of Return**				
Nonassociated Gas			Investor's NPV ($ Million)			IRR	Govt. Take	Investor's NPV ($ Million)			IRR	Govt. Take	Investor's NPV ($ Million)			IRR	Govt. Take	Investor's NPV ($ Million)			IRR	Govt. Take (@10%)
			10.0%	12.5%	15.0%		@10%	10.0%	12.5%	15.5%		@ 10.0%	10%	12.5%	15.5%		@ 10%	10.0%	12.5%	15.0%		
Production (MMCF) 1,096 Price ($/MMCF) 4.5	Investor's		558.2	364.3	226.9	22.7%	34.5%	441.7	280.6	165.2	21.2%	48.2%	428.2	277.0	428.2	21.6%	49.8%	471.1	305.9	186.9	22.0%	44.7%
Capex ($ Million) 1,004 Opex ($/MMCF) 0.25	NOC's		-	-	-			-	-	-			-	-	-			-	-	-		
Price Limit ($/MMCF)			2.35	2.70	3.08			2.53	2.91	3.32			2.31	2.70	3.10			2.28	2.63	3.02		
Sensitivities:																						
Prod.	+20%	767.4	527.8	355.5	26.5%	33.1%	599.3	406.9	267.4	24.7%	47.8%	558.5	386.4	259.4	25.2%	51.3%	606.4	414.1	274.6	25.1%	47.2%
	-20%	339.3	192.8	89.9	18.3%	39.2%	275.5	146.9	56.6	17.2%	50.6%	275.3	152.2	64.6	17.6%	50.6%	301.5	170.2	77.1	18.0%	45.9%
Price	+20%	787.0	543.0	367.4	26.8%	32.3%	640.9	437.7	290.6	25.2%	44.9%	567.6	393.6	265.1	25.4%	51.2%	611.7	418.8	278.6	25.2%	47.4%
	-20%	327.6	183.9	83.0	18.0%	39.6%	243.3	123.8	39.7	16.6%	55.1%	270.1	147.6	60.5	17.4%	50.2%	300.0	168.6	75.4	17.9%	44.7%
Capex	+20%	451.3	266.0	135.5	19.1%	38.0%	341.8	187.9	79.1	17.6%	53.1%	373.7	217.2	105.4	18.5%	48.7%	393.8	229.7	113.1	18.7%	45.9%
	-20%	663.5	461.0	315.0	27.5%	32.1%	542.3	373.7	251.2	26.0%	44.5%	484.3	339.1	231.7	26.2%	50.4%	497.6	344.0	231.8	25.8%	49.1%
Opex	+20%	546.6	355.4	219.1	22.5%	34.7%	431.8	273.1	159.3	21.0%	48.4%	420.9	270.8	162.1	21.4%	49.7%	460.5	297.6	180.3	21.8%	45.0%
	-20%	569.7	373.1	232.8	22.9%	34.3%	451.5	288.2	171.1	21.4%	48.0%	432.6	281.2	171.1	21.8%	50.1%	481.8	314.1	193.4	22.2%	44.5%
		Corp.Tax Expl.Tax	In Lieu 3%	C/R Limit NOC		70% 0.0%	Corp. Tax Expl. Tax	In Lieu 3%	C/R Limit NOC		70% 0%	Corp. Tax Expl. Tax	In Lieu 3%	C/R Limit Royalty NOC	70% 3.0% 0%		Corp Tax Expl.Tax	In Lieu 3%	C/R Limit Royalty NOC	70% 3.0% 0%	
			P/O Split			Royalty		P/O Split			Royalty		P/O Split					P/G Split				
		0 < D/Pro < 250			25%	3%		0 < C/Pro < 280			25%	3%	R/F < 1		10%		RoR <		5%		10%	
		250 < D/Pro < 500			35%	5%		280 < C/Pro < 850			35%	5%	1< R/F < 1.5		30%		5 < RoR <		15%		30%	
		500 < D/Pro < 750			50%	6%		850 < C/Pro < 1400			50%	6%	1.5 < R/F < 2		45%		15< RoR <		25%		45%	
		750 < D/Pro < 1000			65%	8%		1400 < C/Pro < 1700			65%	8%	2< R/F < 2.5		60%		25< RoR <		35%		60%	
		1000 < D/Pro			85%	10%		1700 < C/Pro			85%	10%	2.5< R/F < 3		75%		35< RoR <		45%		75%	
													3 < R/F		90%		45 < RoR				90%	
Stress Test		NPV (10)	(32.1)	NPV (15)	(126.1)			NPV (10)	(4.9)	NPV (15)	(145.0)	NPV (10)	(38.4)	NPV (15)	(117.0)	NPV (10)		(54.1)	NPV (15)	(109.8)		

Figure A5.5: Government Take and Project's IRR at Different C/R Levels – Nonassociated Gas






Associated Gas
Government Take and Project IRR at Different Cost Recovery Limit
Fiscal Model 3
Percentage Government Take
Contractor's Cash Flow (NPV 10%)
0.6
0.5
0.4
0.3
0.2
0.1
0
90
80
70
60
50
40
30
20
10
0
0.1
0.2
0.3
0.4
0.5
0.6
0.7
0.8
0.9
1
Cost Recovery Limit
IRR
Govt Take
NPV

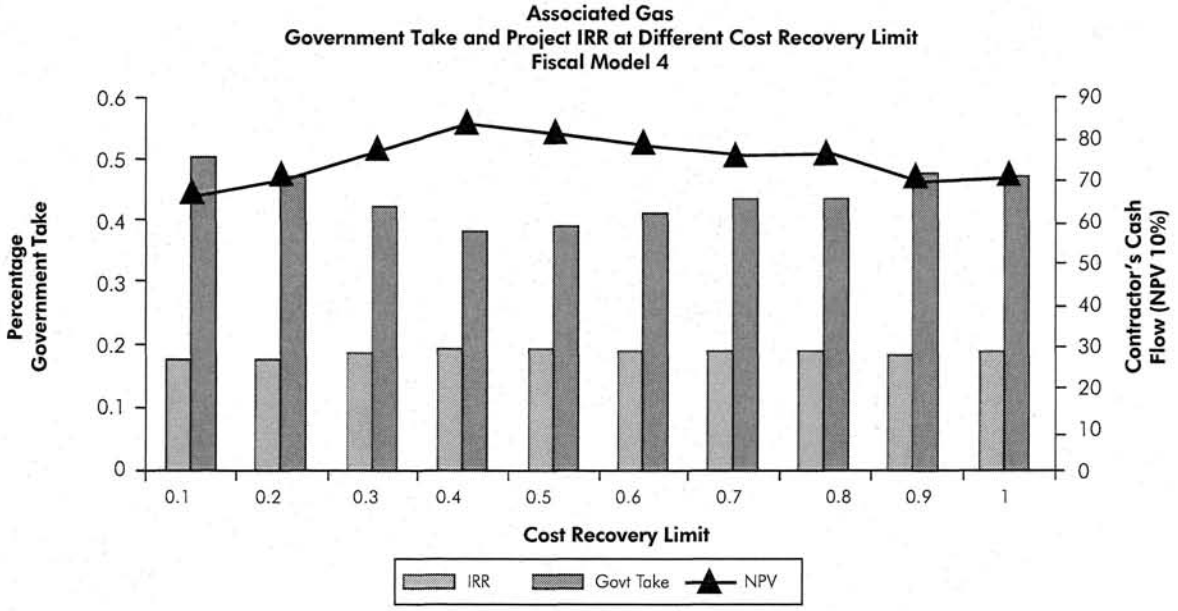
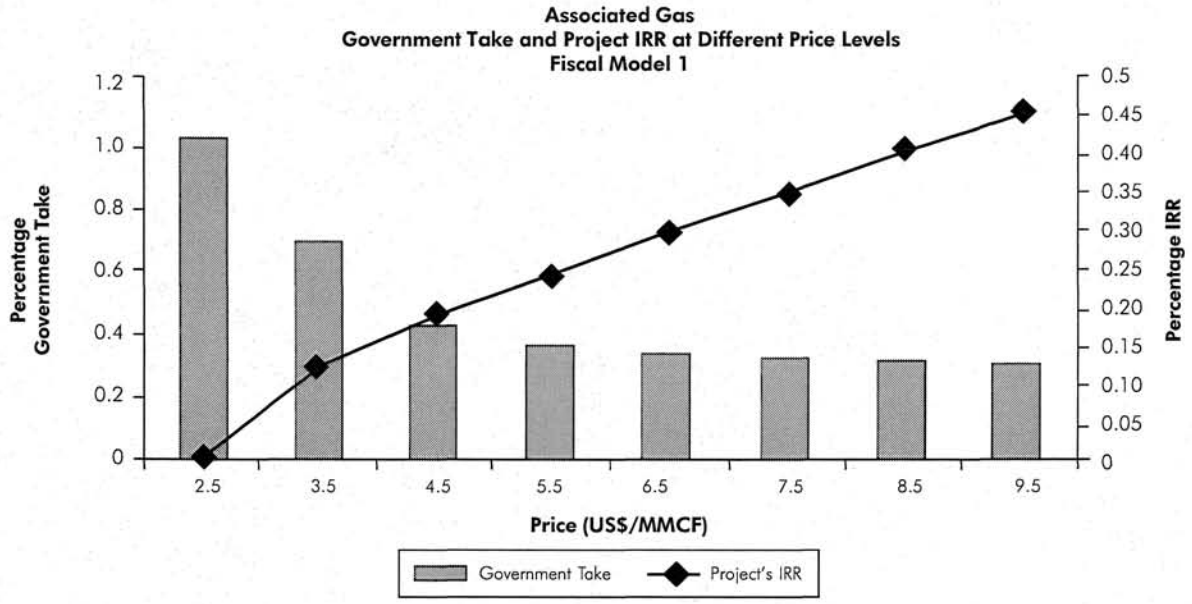
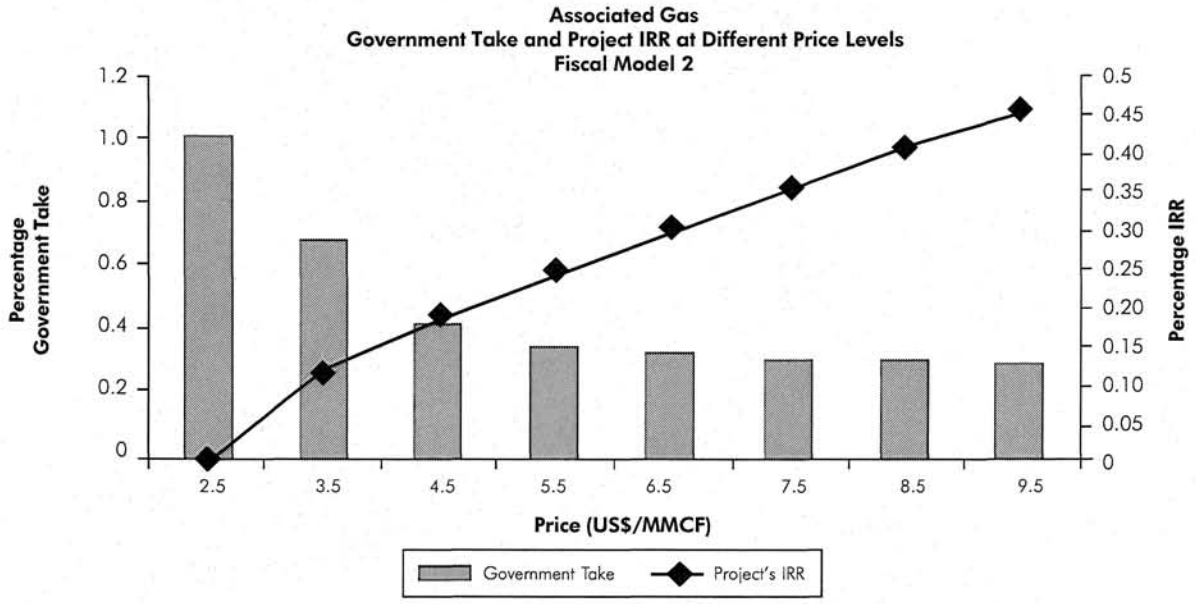
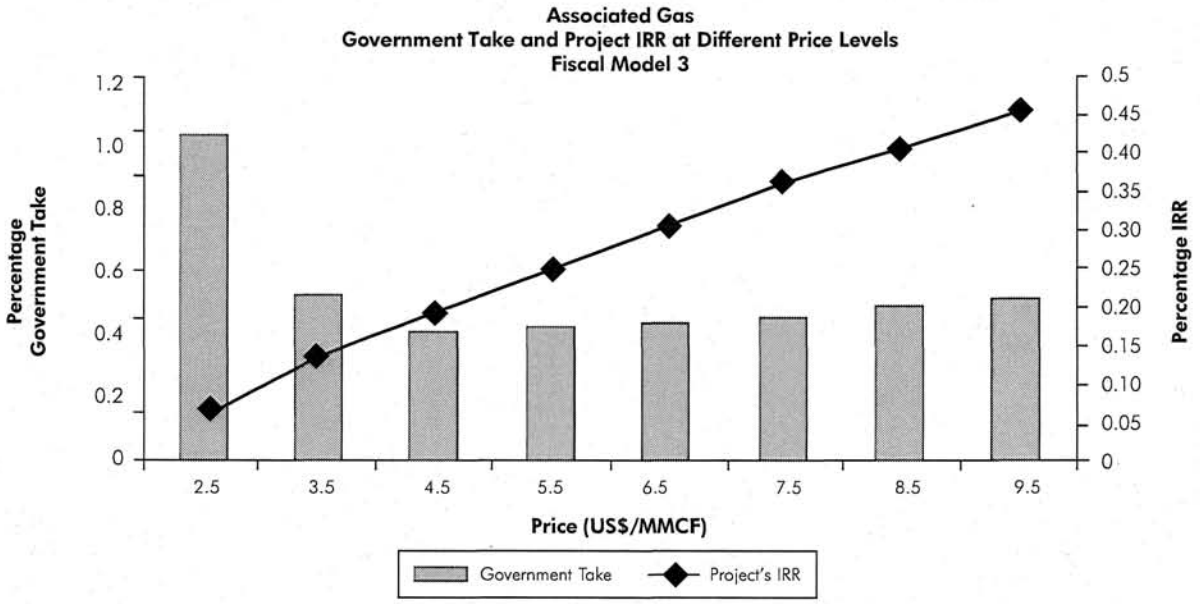
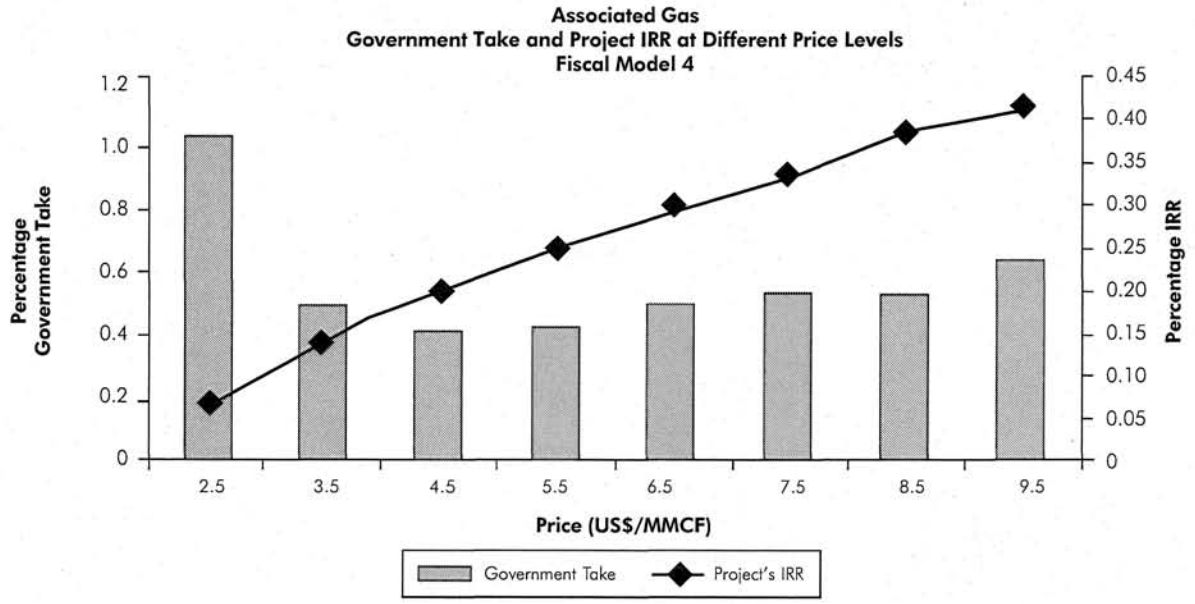

Associated Gas
Government Take and Project IRR at Different Cost Recovery Limit
Fiscal Model 4
Percentage Government Take
Contractor's Cash Flow (NPV 10%)
0.6
0.5
0.4
0.3
0.2
0.1
0
90
80
70
60
50
40
30
20
10
0
0.1
0.2
0.3
0.4
0.5
0.6
0.7
0.8
0.9
1
Cost Recovery Limit
IRR
Govt Take
NPV

Figure A5.6: Government Take and Project's IRR at Different Price Levels – Nonassociated Gas









Note: The combined effect of royalties, cost recovery limit and exploration tax may produce a Government Take above 100 percent. In these cases, the graphs show a Government Take of 101 percent.

Table A5.4: NOC Participation – Nonassociated Gas Project

			Fiscal Model No. 1/Oil					Fiscal Model No. 2/Oil					Fiscal Model No. 3/Oil					Fiscal Model No. 4/Oil				
Production-sharing based on:			**Daily Production**					**Cumulative Production**					**R-Factor**					**Rate of Return**				
Nonassociated Gas			Investor's NPV ($ Million)			IRR	Govt. Take	Investor's NPV ($ Million)			IRR	Govt. Take	Investor's NPV ($ Million)			IRR	Govt. Take	Investor's NPV ($ Million)			IRR	Govt. Take (@10%)
			10.0%	12.5%	15.0%		@10%	10.0%	12.5%	15.5%		@ 10.0%	10%	12.5%	15.5%		@ 10%	10.0%	12.5%	15.0%		
Production (MMCF) 1,096 Price ($/MMCF) 4.5	Investor's		364.3	206.5	107.2	19.2%	59.4%	264.8	148.0	64.7	17.8%	68.9%	256	146	67	18.0%	70.0%	286.1	166.3	80.5	18.5%	66.4%
Capex ($ Million) 1,004 Opex ($/MMCF) 0.25	NOC's		211.8	157.7	118.8			176.9	132.6	100.5			172	131	100			185.1	139.5	106.3		
Price Limit ($/MMCF)			265	3.10	3.58			2.87	3.35	3.87			2.66	3.13	3.72			2.59	3.04	3.65		
Sensitivities:																						
Prod.	+20%	495.3	323.7	200.5	22.5%	56.8%	377.7	239.1	138.9	20.8%	67.1%	350.0	225.6	134.1	21.0%	69.5%	383.5	245.0	144.8	21.1%	66.6%
	-20%	188.5	81.7	7.2	15.3%	66.2%	143.8	49.6	(16.1)	14.3%	74.2%	144.7	54.4	(9.5)	14.6%	74.1%	163.0	67.0	(0.7)	15.0%	70.8%
Price	+20%	509.3	334.5	209.0	22.8%	56.2%	406.9	260.8	155.3	21.3%	65.0%	356.4	230.7	138.3	21.2%	69.3%	387.4	248.4	147.7	21.2%	66.7%
	-20%	180.1	75.2	2.2	15.1%	66.8%	121.1	33.2	(28.1)	13.7%	77.7%	140.8	50.9	(12.6)	14.4%	74.0%	161.7	65.6	(2.2)	14.9%	70.2%
Capex	+20%	258.1	123.4	29.1	16.0%	64.5%	181.5	68.8	(10.4)	14.6%	75.1%	205.0	90.6	9.3	15.3%	71.8%	219.1	99.3	14.6	15.5%	69.9%
	-20%	431.5	286.6	182.3	23.4%	55.8%	346.7	225.4	137.7	21.9%	64.5%	306.7	202.0	124.8	21.9%	68.6%	316.0	205.4	124.8	21.7%	67.7%
Opex	+20%	338.1	200.2	102.3	19.0%	59.6%	257.8	142.6	60.4	17.6%	69.2%	250.8	141.7	63.0	17.8%	70.1%	278.5	160.4	75.8	18.3%	66.7%
	-20%	354.5	212.8	112.1	19.4%	59.1%	271.8	153.4	68.9	17.9%	68.7%	259.2	149.2	69.6	18.1%	70.1%	293.7	172.3	85.2	18.6%	66.2%
		Corp.Tax Expl.Tax	In Lieu 3%	C/R Limit NOC		70% 0.0%	Corp. Tax Expl. Tax	In Lieu 3%	C/R Limit NOC		70% 0%	Corp. Tax Expl. Tax	In Lieu 3%	C/R Limit Royalty NOC	70% 3.0% 30%		Corp Tax Expl.Tax	In Lieu 3%	C/R Limit Royalty NOC	70% 3.0% 30%	
			P/O Split			Royalty		P/O Split			Royalty		P/O Split					P/G Split				
		0 < D/Pro <	250		25%	3%	0 < C/Pro <	280		25%	3%	R/F <	1		10%		RoR <	5%		10%	
		250 < D/Pro <	500		35%	5%	280 < C/Pro <	850		35%	5%	1< R/F <	1.5		30%		5 < RoR <	15%		30%	
		500 < D/Pro <	750		50%	6%	850 < C/Pro <	1400		50%	6%	1.5 < R/F <	2		45%		15< RoR <	25%		45%	
		750 < D/Pro <	1000		65%	8%	1400 < C/Pro <	1700		65%	8%	2< R/F <	2.5		60%		25 < RoR <	35%		60%	
		1000 < D/Pro			85%	10%	1700 < C/Pro			85%	10%	2.5< R/F <	3		75%		35 < RoR <	45%		75%	
												3 < R/F			90%		45 < RoR			90%	
Stress Test		NPV (10)	(49.3)	NPV (15)	(167.8)		NPV (10)	(75.3)	NPV (15)	(181.1)	NPV (10)	(43.2)	NPV (15)		(159.8)	NPV (10)		(32.2)	NPV (15)		(154.7)

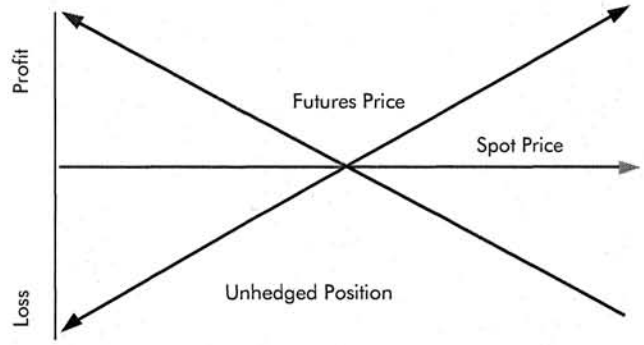
Annex 6
Hedging with Derivatives: Examples and Strategies

This Annex contains example of simple hedging strategies that the government of a gas-producing country may consider in order to make its revenue stream more stable, and to protect it from unexpected price swings. The government could hedge its royalty and production tax revenue because these revenue streams are directly tied to gas prices. It is important to note that the use of futures and options does not oblige the hedger to deliver or take possession of the underlying asset as the position can be reversed before the expiry of the futures contract.

- ***Hedging with futures.*** Futures contract can be used to lock into the prices available in the futures market. For example, the government may have prepared its budget based on the expectation that the price of gas would have averaged US$7.50/MMBTU in 2006. At the time of budget preparation (for example, in September 2005), the government did not know what the actual price of gas will be. Hence, its fiscal revenue is exposed to the risk that unforeseen shocks may cause the spot price of gas to fall below the budgeted price. To protect its revenue from the risk of an unforeseen price fall, the government could decide to sell a series of futures contracts with deliveries matching the pattern of the fiscal revenue to be hedged. The government would not need to hold the contracts until expiry (otherwise, it would be obliged to deliver the corresponding quantity of gas): each contract would be terminated through a reverse transaction in the futures market (buying futures before each contract's expiry date). The graph below shows the payoff to the government for selling a futures contract.

One possible strategy could be to sell, four months ahead, futures contracts in a quantity equivalent to the monthly revenue to be

Figure A6.1: Payoff for Selling a Futures Contract



hedged,[270] and buy futures contracts in the same monthly quantity one month ahead of the expiry date of each futures contract sold. Had the government applied this strategy in 2006, it would have obtained an average gain in the futures market of US$1.24 MMBTU, which would have increased the average gas price for the year from US$7.07 MMBTU (the unhedged or spot price) to US$8.31 MMBTU.[271] The result of this strategy is represented in the graph below.

The success of this type of strategy depends on the relationship between futures and cash prices, the market outlook and the timing of the hedge (for example, the result of the strategy illustrated above would have to be different if hedging is done 12 months ahead instead of each quarter[272]). Triggers for selling and buying futures could also be established to improve the effectiveness of the strategy and/or to limit the losses. The government would incur losses when the market moves against its position. Because futures contracts are marked-to-market each day, cash transfers to and from the broker would take place.[273] In addition, the government would have to pay the margins for each contract it bought and sold. Hence, to execute this strategy, the government would need to secure enough liquidity to face its obligations toward the broker. Specific budget appropriations may be needed to honor these obligations.

- **Hedging with options.** Whereas the holder of a futures contract has an obligation to perform (that is, the holder is committed to a price in advance), an option gives its holder the right to choose whether or not to perform. In our example, instead of committing in

Figure A6.2: Selling Futures Four Month Ahead

Sources: NYMEX, the Energy Information Administration and the World Bank Treasury Department.

[270] *Because futures contract are based on MMBTU of gas, the government will have to determine how many MMBTU it will have to hedge to protect its anticipated revenue. In other words, it would need to determine the hedge ratio (see below). To be noted that the hedge ratio can be calculated also with respect to cash revenue from royalties, production-sharing and corporate taxes, that is, the government can hedge its revenue stream whether or not it has access to the physical commodity. It is important to note that producing companies are quite likely to have a hedging program. The objectives and success of the program, and accounting treatment of gains/losses arising from the program may affect the level of tax revenue of the host government (Statoil Steers the Course in Risk Waters Group Ltd, 2000).*

[271] *In the example, spot and futures prices are quoted with reference to the last trading day of each month. To simplify, we have assumed that the actual price that the government receives each month corresponds to the spot price on the last trading day of the month. Although, in reality, this may not be the case – the hedge is not perfect – the profit generated in the futures market would contribute to compensate the loss in actual revenue compared to the budgeted revenue.*

[272] *The more liquid segment of the market is the near term, one to four months into the future. Hence, it could be difficult for a government who needed to hedge large quantities of gas to do so further out into the future.*

[273] *However, the government could choose to trade futures in the OTC market, and structure the transaction to provide for less frequent settlement – for example, monthly instead of daily – or settle on a price average instead of the daily closing price, etc.*

September 2005 to a price in January 2006 (four months in advance), the government could have bought put options and locked into the futures price, but waited until January 2006 to decide whether or not to enter into the contract. In other words, with futures, the government locks in a price, with options the government pays a fee to guarantee a minimum price, while retaining the possibility of receiving a higher price. Options are traded for a number of strike prices below and above the market value of the underlying futures contract.[274] The further away the strike price is from the trading price, the lower the cost of the option (the premium) because there is less likelihood that the option will be exercised. The further out in time, the more an option at any given strike price costs because of increased price uncertainty and the longer period of time the option holder is protected from adverse price movements. Options-based hedging strategies the government could implement include:

- Purchase put options at strike prices at some level below the futures price for each month. For example, the government could elect to hedge at US$1 below futures prices, thus ensuring that it would at most lose US$1/MMBTU (plus the cost of the options) from what the futures market predicts it should earn, while still maintaining full upside price potential;
- Determine a minimum gas price to protect with a hedge and pay whatever the cost of options for that strike price. For example, the strike price could be set to correspond to the minimum gas price below which the government's ability to finance essential expenditure programs would be compromised;
- Budget the amount the government would be willing to pay for an insurance policy and select the strike price that would exhaust this amount. The government could follow this approach to maximize the level of protection within the limit of existing financial constraints; and
- Purchase put options at strike prices at some level below the futures price for each month and sell call options at a strike prices

Figure A6.3: Payoff for Buying a Put Option

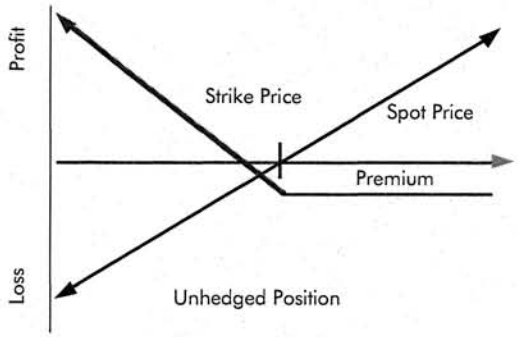
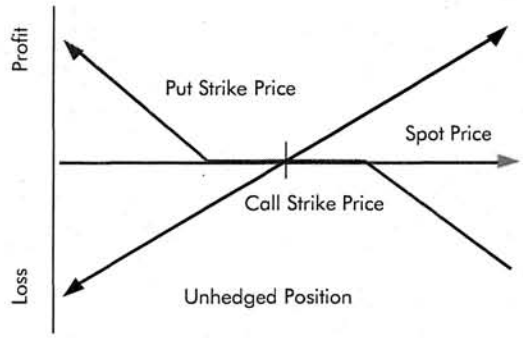


Figure A6.4: Payoff for Buying a Zero-cost Collar



[274] *The NYMEX offers a total of at least 81 strike prices in the first three nearby months and a total of at least 61 strike prices for four months and beyond between in-the-money (above the price of the underlying futures) and out-of-the money (below the price of the underlying futures) strike prices. The increments vary for nearby (US$0.05/MMBTU) and far out (US$0.25/MMBTU) months. Options are also traded in the OTC market, where the contract terms can be customized to better suit the needs of the parties.*

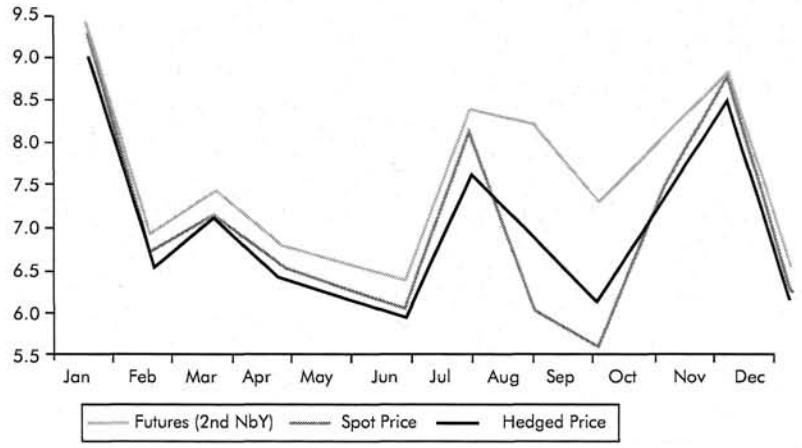
corresponding to the fee that exactly offsets the fee it must pay for the put option.[275] This strategy is called a "zero-cost collar."[276] The government would not incur the out-of-pocket cost of the premium, but with the sale of a call option it would sacrifice the upside revenue potential from higher prices. The put strike price would, however, provide guaranteed minimum revenue.

The graphs above below show the payoff to the government for selling a put option, and for entering into a zero-cost collar.

As for the futures strategy, the government would have to determine the timing of the hedge and the amount to be hedged. For example, if the government had decided to hedge its 2006 expected monthly revenue stream two months ahead by buying options for a strike price of US$1.0/MMBTU lower (US$1 OTM – Out of The Money – Put) than the market value of the underlying futures contract (2nd near by contract), it would have exercised its option in August and September only, when the strike price of the option was higher than the spot price, it would have obtained an average yearly price – net of the cost of the premium – approximately the same as the spot price (unhedged price). A graphical representation of this strategy is shown below:

- **Hedging with swaps**. As for all OTC contracts, commodity swaps can be customized to suit the specific needs of the participants. For example, should the government seek to achieve the average gas price for a given month using exchange-based futures contracts, it would need to settle contracts daily throughout the month to receive the monthly average price. The terms of an OTC swap contract, on the other hand, could be explicitly based on the monthly average price, simplifying program management. Alternatively, an OTC swap contract could be written to average the price over several months, thus, smoothing government revenue, or to settle less frequently – monthly instead of daily – thus reducing overhead costs.

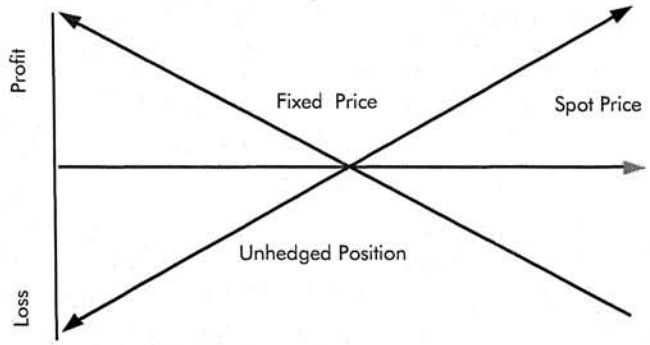
Figure A6.5: Buying Out-of-the-money Options Two Months Ahead



Sources: Nymex, the Energy Information Administration, and the World Bank Treasury Department.

[275] *For any put option strike, price with a fee establishing a seller's floor, there is a call option strike price with an identical fee establishing a purchaser's ceiling.*
[276] *Put-and-call options can, of course, be combined to generate more complex hedges, at zero or near-zero cost.*

Figure A6.6: Payoff for Selling a Swap

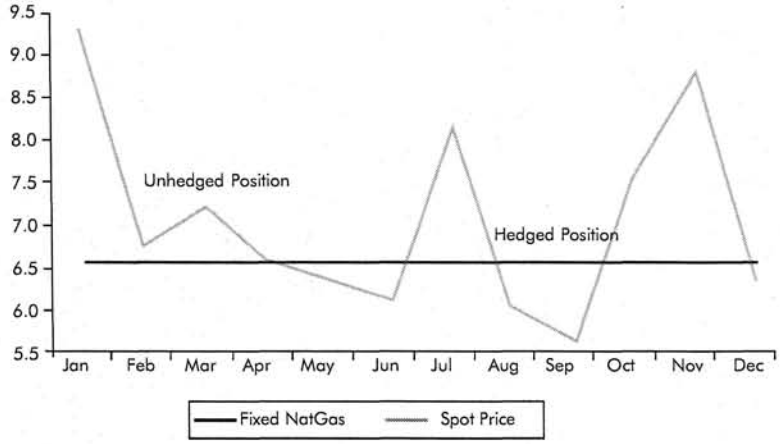


The payoff for selling a swap is shown in the graph below.

As mentioned above, the parties can customize the terms of a swap to fit their specific needs. For example, the government may enter into a fixed-for-floating swap with a financial institution, on the basis of which at the end of each calendar month the government would pay the financial institution if the spot price is higher than US$6.50/MMBTU, and would receive payment from the financial institution in the opposite case. The value of such payments would correspond to the difference between spot price and reference price multiplied by the notional amount of the contract (that is, the volume to be hedged). With this strategy, the government would ensure that the price for gas during the entire budget year would be US$6.50/MMBTU, no matter what the spot price turns out to be. For this insurance, the government would give up the possibility of benefiting from an increase in price above US$6.50/MMBTU. A graphical representation of this strategy is shown below.

In our example, the minimum gas price that the government secured turned out to be below the actual market price in seven over the 12 months the hedge was in place. The government secured a fixed price of US$6.50/MMBTU for each month. Had it not entered into the swap, it would have obtained an average price of US$7.07/MMBTU over the year, but it would have experienced ample variations in price across the year.

Figure A6.7: Setting the Price with a Fixed-for-floating



Sources: NYMEX, the Energy Information Administration and the World Bank Treasury Department.