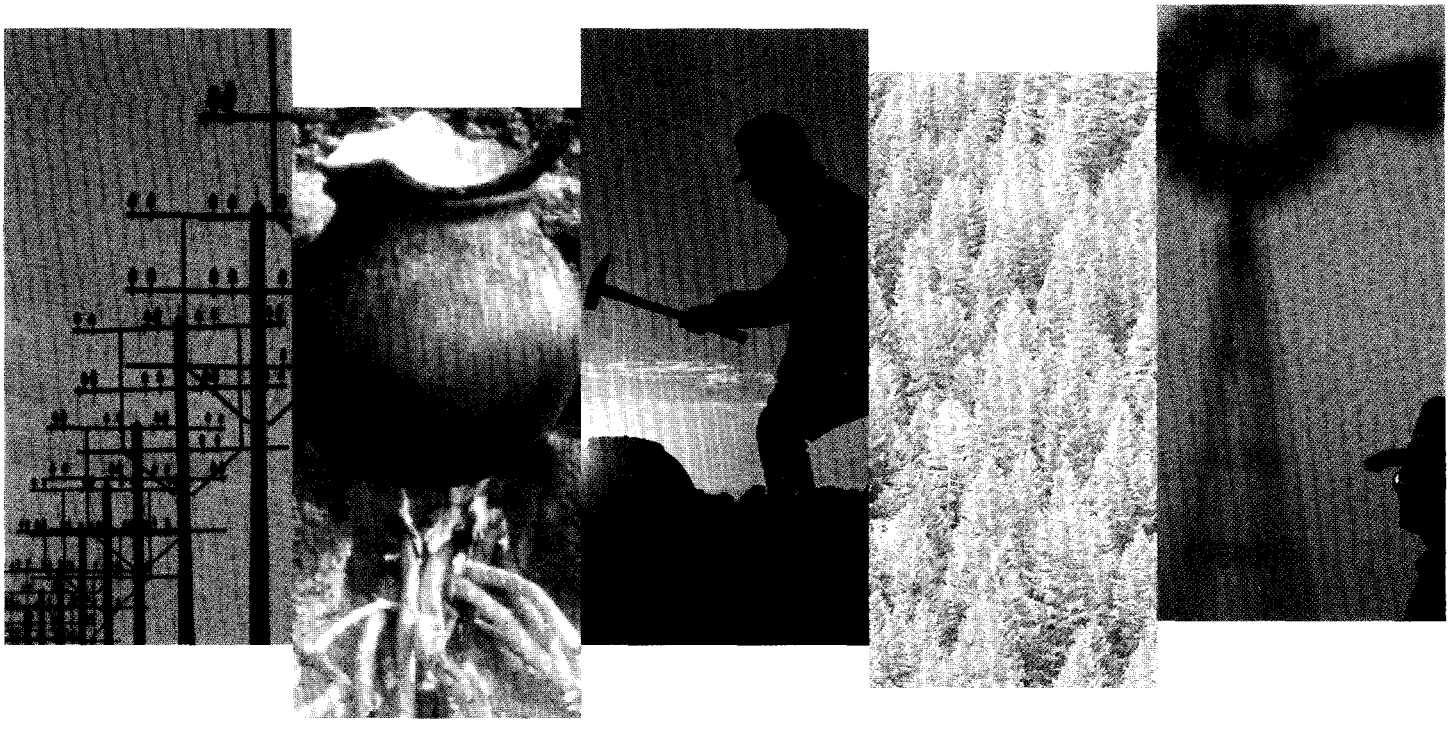
Public Disclosure Authorized

Public Disclosure Authorized

ESM225

Commercializing Natural Gas: Lessons from the Seminar in Nairobi for Sub-Saharan Africa and Beyond



Energy

Sector

Management

Assistance

Programme

ESMAP

Report 225/99

January 2000

JOINT UNDP / WORLD BANK
ENERGY SECTOR MANAGEMENT ASSISTANCE PROGRAMME (ESMAP)

PURPOSE

The Joint UNDP/World Bank Energy Sector Management Assistance Programme (ESMAP) is a special global technical assistance program run as part of the World Bank's Energy, Mining and Telecommunications Department. ESMAP provides advice to governments on sustainable energy development. Established with the support of UNDP and bilateral official donors in 1983, it focuses on the role of energy in the development process with the objective of contributing to poverty alleviation, improving living conditions and preserving the environment in developing countries and transition economies. ESMAP centers its interventions on three priority areas: sector reform and restructuring; access to modern energy for the poorest; and promotion of sustainable energy practices.

GOVERNANCE AND OPERATIONS

ESMAP is governed by a Consultative Group (ESMAP CG) composed of representatives of the UNDP and World Bank, other donors, and development experts from regions benefiting from ESMAP's assistance. The ESMAP CG is chaired by a World Bank Vice President, and advised by a Technical Advisory Group (TAG) of four independent energy experts that reviews the Programme's strategic agenda, its work plan, and its achievements. ESMAP relies on a cadre of engineers, energy planners, and economists from the World Bank to conduct its activities under the guidance of the Manager of ESMAP, responsible for administering the Programme.

FUNDING

ESMAP is a cooperative effort supported over the years by the World Bank, the UNDP and other United Nations agencies, the European Union, the Organization of American States (OAS), the Latin American Energy Organization (OLADE), and public and private donors from countries including Australia, Belgium, Canada, Denmark, Germany, Finland, France, Iceland, Ireland, Italy, Japan, the Netherlands, New Zealand, Norway, Portugal, Sweden, Switzerland, the United Kingdom, and the United States of America.

FURTHER INFORMATION

An up-to-date listing of completed ESMAP projects is appended to this report. For further information, a copy of the ESMAP Annual Report, or copies of project reports, contact:

ESMAP
c/o Energy, Mining and Telecommunications Department
The World Bank
1818 H Street, NW
Washington, DC 20433
U.S.A.

Commercializing Natural Gas: Lessons from the Seminar in Nairobi for Sub-Saharan Africa and Beyond

January 2000

Joint UNDP/World Bank Energy Sector Management Assistance Programme
(ESMAP)

Copyright © 1999
The International Bank for Reconstruction
and Development/THE WORLD BANK
1818 H Street, N.W.
Washington, D.C. 20433, U.S.A.

All rights reserved
Manufactured in the United States of America
First printing July 1999

ESMAP Reports are published to communicate the results of the ESMAP's work to the development community with the least possible delay. The typescript of the paper therefore has not been prepared in accordance with the procedures appropriate to formal documents. Some sources cited in this paper may be informal documents that are not readily available.

The findings, interpretations, and conclusions expressed in this paper are entirely those of the author(s) and should not be attributed in any manner to the World Bank, or its affiliated organizations, or to members of its Board of Executive Directors or the countries they represent. The World Bank does not guarantee the accuracy of the data included in this publication and accepts no responsibility whatsoever for any consequence of their use. The Boundaries, colors, denominations, other information shown on any map in this volume do not imply on the part of the World Bank Group any judgement on the legal status of any territory or the endorsement or acceptance of such boundaries.

The material in this publication is copyrighted. Requests for permission to reproduce portions of it should be sent to the ESMAP Manager at the address shown in the copyright notice above. ESMAP encourages dissemination of its work and will normally give permission promptly and, when the reproduction is for noncommercial purposes, without asking a fee.

Contents

Tables

Figures

Preface

Natural gas has become the world's premier energy source because it is efficient, adaptable, and environmentally safer than other fossil fuels. Developing countries in regions all over the world—particularly in Asia and Latin America—that were formerly dependent on coal and oil have been seeking to develop their gas reserves and to facilitate trade of gas via pipeline or shipments of liquefied natural gas (LNG). The principal use of gas in developing countries is typically in electrical power generation, in the highly efficient combined cycle gas turbine (CCGT). But gas is also adaptable for use by industry and commerce, as well as for chemical feedstocks, where sufficient markets exist or can be developed. As the Global Environment Facility has emphasized, incentives to capture and convert gas to commercial use are heightened in countries that are oil producers, where associated gas is often wastefully flared (or, worse, vented), contributing to damage of the ozone layer.

ESMAP has been active in promoting the development of commercially viable gas projects in Africa for some time, conducting pricing, market, institutional/regulatory, and technical analyses in Morocco and Egypt, for example. In Sub-Saharan Africa (SSA), in cooperation with the Africa region of the World Bank, ESMAP has been active since the mid-1990s in the Africa Gas Initiative. In that project, ESMAP has been working in countries such as Angola, Cameroon, Congo, Chad, and Gabon, Sierra Leone, South Africa, and Tanzania on a variety of studies aimed at assessing the potentials for commercial gas projects and the instrumentalities for making them into a reality.

As part of its effort to promote the development of clean and efficient energy in Africa, ESMAP held a seminar for participants from Sub-Saharan African countries in Nairobi, Kenya, from 23 to 26 June 1997. The seminar focused on commercializing natural gas in Africa—a particular challenge because markets for gas there are constrained by the generally low levels of income and industrialization and by the relatively diffuse nature of economic activity, which renders gas transport comparatively costly. The seminar thus explored how to create an efficient gas industry from both an economic and commercial viewpoint and how to facilitate the development of commercial gas projects. Toward those ends, it is necessary to understand the factors involved in attracting international investment and in mobilizing domestic resources.

The seminar featured presentations and panel discussions by analysts and practitioners from developed countries as well as reports on ongoing gas development projects such as the Pande, Songo Songo, and Kudu fields from African policymakers and administrators. The wide-ranging discussions covered issues of national policy, project finance and risk, scale of projects, appropriate applications for gas, pricing, regulation, cross-border agreements, environmental impacts, and many other topics of interest. The seminar highlighted the entire spectrum of generic elements necessary to commercialize natural gas along with some specific aspects of ongoing and proposed African projects.

A key point that emerged from the seminar was that successfully commercializing a gas project faces challenges in fulfilling four main conditions:

1. Successfully proving gas reserves.
2. Successfully developing a market for gas.
3. Economically bridging the distance between reserves and market.

4. If conditions 1–3 are met (i.e., the project is economic), the right incentives and framework must be set up to attract private capital to realize the project commercially.

Condition 1 is already a given in many parts of Africa; often gas is proved as a by-product of the search for oil.

Conditions 2 and 3 have proved especially challenging for gas development projects in Africa. Because of its dependence on a fixed distribution infrastructure of transmission and, if applicable, distribution pipelines, gas usually must be marketed locally rather than exported to the established markets in the United States, Japan, and Western Europe. The question therefore is whether an economically viable domestic market for gas can be established.

For gas in particular, then, the rules of the domestic market with respect to risk, pricing, ownership, and many other factors must be clearly defined for the participants in the market. If these rules are not defined in a satisfactory way to all potential participants, none may participate.

Thus, the difference between an economically viable project and a commercial project must be borne in mind. The fact that a project may be *economic* is not enough to attract private investors who will turn it into a *commercial* project. Private investors will engage commercializing a project if and only if the state creates a reliable framework defining an attractive balance of risks and opportunities.

Because the Nairobi seminar covered generic points of interest for facilitating commercial gas projects, and because of the worldwide interest in that subject, it seemed worthwhile to make the content of the seminar available to an audience beyond the one focusing on Sub-Saharan projects. Given the comparatively informal nature of the discussions at the seminar, ESMAP is not attempting to just reproduce the presentations, dialogues, and discussions just as they took place in Nairobi. Instead, the present paper attempts to synthesize and summarize the main observations and lessons of the seminar. The paper tries to include as much of the original substance of the presentations at the seminar as possible, but in the interest of consolidating information on specific topics, it follows neither the sequence of the presentations nor the detailed argumentation of each individual paper. It also reproduces only a small selection of the charts shown in Nairobi.

The main body of this report deals with the generic aspects of commercializing natural gas in a developing country. The focus of course is on conditions typical for Sub-Saharan Africa—that is, an emergent gas industry in a developing country with a low per capita income in a climate not needing space heating. But because these conditions apply widely outside SSA, the main body of the report was written without extensive reference to conditions unique to SSA so that it could be useful for other developing countries with potential for creating a gas industry.

Three Annexes to the report do focus specifically on issues unique to commercializing natural gas in SSA and on the Nairobi seminar itself. Annex A summarizes the seminar discussions on the conditions for gas development in SSA and provides details of several Sub-Saharan African projects.

Annex B reproduces the original seminar program and provides a full list of participants, authors, and conference organizers, including and addresses and email coordinates, for readers who may be interested in further dialogue.

Annex C gives an outline of each of the seminar papers. In addition, readers with Internet access who are interested in further information may wish to consult ESMAP's World Wide Web site:

http://www.esmap.org

Acknowledgments

This report synthesizes and summarizes the presentations at the workshop, Commercialization of Natural Gas, held in Nairobi from 23 to 26 June 1997. The workshop was organized as a cooperative effort between the World Bank and Petrad, with financial support from Norway. The workshop was conducted with alternating lecture sessions and group and plenary discussions.

Ralf Dickel prepared this report. Eric Daffern, Bent Svennson, Peter Law, Clive Armstrong, and Robert Bacon provided valuable comments, and Paul Wolman edited the manuscript. Their assistance is gratefully acknowledged.

Abbreviations and Acronyms

bcm	Billion cubic meters
Btu	British thermal units
CCGT	Combined cycle gas turbine
CO_2	Carbon dioxide
ENH	Empresa Nacional de Hidrocarbonetos (Mozambique)
GDP	Gross domestic product
IPP	Independent power producer
kWh	Kilowatt hours
LNG	Liquefied natural gas
mtoe	Million tons of oil equivalent
LPG	Liquid petroleum gas
MMBtu	Million British thermal units
MWel	Megawatt electric capacity
MWh	Megawatt hour
MWth	Megawatt thermal capacity
SADC	Southern Africa Development Community
SO_2	Sulfur dioxide
SSA	Sub-Saharan Africa

Note: Gas is used for natural gas, a mixture of mainly methane and other higher hydrocarbons that are gaseous at ambient pressure and temperature.

Gas oil is used for Diesel / distillate.

Executive Summary

1. The first chapter describes some basic features and requirements of gas projects in an effort to guide policymakers in making a preliminary judgment about the feasibility of developing a gas industry. The text warns against some common misperceptions and premature conclusions while hinting at some tools of analysis that might give an impression of whether *any* chance exists for fielding an economic project.

2. Chapters 2 through 5 take up the dimensions of a more detailed analysis to ascertain whether a gas project is in fact economically viable. This question is examined from an economic angle, comparing total supply costs for gas in a proposed scheme with the total value of the gas delivered, with a view toward determining whether a proposed project would make a positive contribution to the economy of a nation. Such an analysis should be based to the largest extent possible on international market prices. It does not distinguish which of the participants in the gas industry or in the economy would profit or lose; rather, it looks at costs and revenues in total. The value of the gas is derived by comparing the cost of using gas with the costs of using alternative fuels. It also includes externalities such as extra costs or benefits to the greatest extent possible, because externalities also represent costs and profit to a country—just ones that may accrue to persons not immediately engaged in the gas industry.

3. In countries such as those of Sub-Saharan Africa, the use of gas for power generation will be crucial to start a gas industry of the substantial size needed to economically justify the development of a larger field and the building of a steel pipeline. However, also small gas schemes based on power generation in small units using polyethylene or aluminum pipelines for transportation may be viable schemes to make use of the benefits of gas as a clean fuel. They are dealt with in chapter 6.

4. Based on these investigations it is possible to determine whether a given gas project is favorable for a given country. However, confirming that a project is economically feasible must not be taken as guaranteeing that the project will attract enough of the right commercial entities to come to fruition. To attract investment, the sector must have clearly defined rules so that each entrant into the market views the balance of opportunity and risk as attractive and trusts the organizers of the institutional and regulatory system to observe and enforce the rules fairly over the lifetime of the project. For the organizer of the system, that means ensuring that the opportunities and risks of all participants (including those associated with the costs of maintaining the system) are manageable. It also means that the opportunities in the sector must be advertised well enough to attract a minimum number of participants.

5. Chapters 7 through 10 pursue the vital issues of creating the incentives and the legal, regulatory, and contractual frameworks for a commercial project and for participation of the private sector in it.

6. Chapter 11 deals with the key elements of private participation—risk mitigation and financing. In this regard, the price of financing (i.e., through international capital) is influenced by the country risks and the other risks perceived about a project in a given country. Although some parts of the project (e.g., reservoir or technical performance risks) are not country-dependent, others—such as marketing, currency, and the willingness of the customer to pay—are country-dependent or at least perceived as such. The task of the government and of international financing institutions thus is to

arrange the financing of an economic project in such a way that the country-specific risks become as small as possible—or at least to ensure that the risk perceived is not larger than the actual risk.

7. The most important conclusions drawn in chapter 12 of the paper are as follows:

- Gas projects are driven by demand rather than by production. Gas without a paying demand does not have a value per se. Proving gas reserves is just the beginning.
- Although large demand volumes are usually needed to make gas projects economic, the potential of small projects should be explored.
- Once an economic gas project is identified, the challenge in commercializing that project is to define a policy and resulting regulatory framework that will attract investors and benefit the citizens of the country.
- The state should define the benefits for all participants, making them attractive and clear to all players. This includes the interest of the state's citizens with regard to safety and environment. It requires transparent and open processes for all stakeholders so that they can participate in the decisionmaking process.
- Economic regulation should be adequate to the shape and stage of the gas industry. It should avoid overregulation. Likewise, it should avoid copying complicated or excessively sophisticated regulation models. However, the further expansion of the gas industry should be kept in mind.
- A crucial point in attracting international investors will be in assuring them that they will be able to realize the income from the project in line with international energy prices in hard currency.

8. Above all, the parties involved should have not only the courage to invest in promising projects but also the courage to build mutual trust through sound practice, cooperation, and good will.

1

Basic Features of Natural Gas Projects

1.1 Two perceptions of gas projects are widespread: (1) gas projects are like oil projects because gas is found through the same process as oil; (2) gas development is like electricity development because both infrastructures are grid-bound. Although gas and oil as well as gas and electricity do have some underlying similarities, neglecting the features specific for gas will put the development of a sound gas industry at risk. The examination below focuses on the fundamental features of gas projects.

Basic Relations between Oil and Gas Projects

1.2 Within the hydrocarbon sector, oil and gas projects share some basic features, such as separation into upstream and downstream components in which the upstream consists of exploration and production and the downstream of transportation, distribution, and consumption. Moreover, the two fuels are often in direct competition: upstream, gas competes with oil for investment, and downstream, gas competes with oil products for customers. Beyond this, however, the two subsectors exhibit some distinctive differences that underline the importance of specific expertise in gas projects.

1.3 The feasibility of gas projects often depends on exploiting the advantages of gas and compensating for its disadvantages. Some economic challenges of developing gas projects are as follows:

- *Gas has substantially higher transport costs than oil between production and market.* Because of its much lower specific energy content per volume, natural gas has much higher specific transportation costs. Gas must be transported in pipelines under pressure, and even under high pressure (e.g., 100 bar), gas has a specific energy content per volume of only about a tenth that of oil. The same vessel or pipeline thus handles at most about a tenth of the energy content in gas compared with oil.
- *Gas has higher storage costs.* Again because of its low energy density and its volatility, gas needs to be stored in sealed containment and needs much higher volumes for the same amount of energy compared with oil.
- *The economics of gas projects are highly sensitive to geographic factors.* Because of the limitations of gas with respect to both transport and storage, gas projects are economically very sensitive to geographic factors such as distance between the production site and the main consumption areas and concentration of demand. It may be economic to serve a given market with oil products but clearly uneconomic to serve it with gas.

At the same time, natural gas also has advantages in comparison with oil:

- *Gas burns more cleanly than other fossil fuels.* Downstream, gas is cleaner burning and easier to handle than coal or oil products, except for the more expensive oil products such as gas oil and liquids. The cleaner-burning gas is thus both more efficient in terms of operation and maintenance as well as more beneficial environmentally.
- *Gas is a high-efficiency fuel.* Gas has considerably higher efficiency in power generation compared with heavy fuel oil and coal and will therefore achieve a premium over those fuels in most power markets. Once a customer is linked to gas, gas is easier and more convenient to handle than oil.
- *Large gas reserves have been proven.* In many areas, exploration drilling focused on oil prospects but not on gas prospects, so gas finds were mostly byproducts of the search for oil. The potential for additional gas finds may increase when exploration is specifically focused on gas prospects.

Basic Relations between Gas and Electricity

1.4 The main relation gas bears to electricity is that gas is an input for electricity generation. Gas and electricity do not compete with each other in the end-consumer market, except where gas heating might compete with electric heating in households or in some industrial processes (e.g., using induction furnaces). A main area of competition between gas and electricity stems from the issue of whether energy is better transported as a hydrocarbon fuel (e.g., natural gas) or as electricity via wire to the place of final consumption.

1.5 Common features are that both gas and electricity are grid-bound; local gas grids are indeed similar to electricity grids. This may suggest that both energies can be dealt with through similar regulatory approaches, even if electricity grids tend to be much more densely interlinked than gas grids.

1.6 The differences between gas and electricity are (1) contrary to gas production, electricity generation is not principally locally bound; and (2) gas can always be substituted by the customer, whereas electricity cannot. Although the production of hydroelectricity—like that of gas—is bound to given locations that are defined by nature and may or may not be close to market, thermal power plants can generate electricity anywhere, and their location therefore can be optimized in relation to the markets or customers served. Because power generation is the most important application for gas, especially in warm countries, the question arises of where gas should be transformed into electricity with regard to transport and distribution. Thus, one must carefully assess the merits of whether the gas should be brought to the power plant, close to the electricity consumption area, or whether the power plant should be built close to the gas-production site. That is, one must consider the relative economic merits of transporting and distributing the electricity versus transporting and distributing the gas to power generation closer to electricity demand. For distributed (more local) power generation, that raises the questions of additional expenditures for the distribution of the fuel to the various power plants and the loss of economies of scale when power is generated in smaller units to match the size of local demand.

1.7 When answering these questions, one has to look at the specific facts of the case. The percentage of losses in electricity transmission is in general higher than the percentage of gas used for boosters in gas pipelines. Also the specific investment per energy transport capacity tends to be lower for gas transportation compared with power transmission for larger schemes dealing with large amounts of

energy. So, transport of gas tends to be cheaper than transport of electricity. However, soil conditions may influence the comparison heavily: rocky soil or many river crossings can make burying gas pipelines very costly, whereas the erection of pylons for electric cables may be relatively easy so that power transmission becomes cheaper than gas transport. Beyond the mere comparison of transport economics, bringing gas to a power plant near a marketplace can have the advantage of opening an additional demand for the gas that would add to the economic viability of a gas project. In any case, the electricity brought to the marketplace should be competitive with local power generation based on gas oil. For gas oil, transportation costs may be low, because it can be easily stored and does not need an infrastructure that binds investment to specific locations.

1.8 When it comes to defining the rules of the market, oil, gas and electricity have important differences. Whereas oil and oil products are best left to market forces with as little as possible interference by the state, electricity must usually be regulated. This is not least because of the inelastic demand for electricity (implying a high price ceiling set by the costs of power shortages or of operating substitute local generation). Electricity tends to be organized as a national monopoly, which often does not even allow for autogeneration. Also, as a precondition for a reasonable standard of living, everyone needs access to electricity—even if just for lighting. Therefore, utilities often have a public service obligation because of that basic need for electricity and the difficulty of substituting for it. Strict regulation of electricity prices is hence the rule. Substitute oil products, which are available on a world market and whose distribution can be handled by local small- and medium-sized business, on the other hand, usually can replace gas. Therefore, gas can hardly be considered as a basic need for which a public service obligation should be established. The free choice of substitutes for gas is usually a very good protection for the gas consumer. The price of gas substitutes can be derived from a functioning world market, although national distortions may result from taxation or price administration. However, access rules to gas pipelines may be necessary to ensure access to the benefits of gas to a broader range of customers, especially to medium-sized customers.

Viability of Gas Projects: An Iterative Approach

1.9 As a first step toward identifying whether a gas industry can be economic for a country, it may be helpful to look at the gas reserves and the potential market to decide if a domestic gas market can be developed or if gas should be exported or imported. The relationships between the two fall into four basic cases (Table 1).

Table 1: Relation between Domestic Gas Reserves and the Potential of the Domestic Gas Market

Level of domestic gas reserves	*Domestic market potential high*	*Domestic market potential low*
High	**Case 1.** Gas for power and other domestic uses plus (possibly) export projects.	**Case 2.** Export gas directly or indirectly.
Low	**Case 3.** Import.	**Case 4.** Small gas projects or no project.

1.10 Case 1 usually involves using gas for power generation and possibly for exports when the domestic market for gas is not large enough or not yet developed sufficiently to absorb the domestic gas reserves. Even in countries that might have large, high-density populations, the domestic use of gas is likely to be constrained by climate or possibly by the ready availability and cheapness of oil. Thus, beyond its use in power generation, gas would probably first be exported before coming into substantial use domestically. (In Africa, Case 1 seems to apply only to Côte d'Ivoire and to Nigeria.)

1.11 The basic scenario of Case 2—high unexploited or underexploited reserves combined with low density of markets—is common in many developing countries. Most of these countries have a gas demand that is small compared with the size of the gas reserves and especially with respect to the cash flow that would be required to develop the reserves and bring the product to market. Thus, they would not be likely to mobilize gas for direct or indirect domestic use. On the other hand, countries with major fields could have gas reserves large enough to justify an export project or a project to export indirectly the value of the gas. (Pande, in Mozambique, and Kudu, in Namibia, are such fields.)

1.12 Case 3, involving low domestic supply but substantial potential demand, suggests that policymakers might consider the economics of importing gas. (For the time being, however, this scenario appears applicable in Africa only in the case of South Africa, where markets are within reach for gas from Mozambique, for example.)

1.13 Case 4 indicates that no major project would be practical. Nonetheless, small gas projects might still be established. Because of innovations in the use of plastic pipelines that make them easy to join and lay, and because of the potentials for low-price power generation by small gas turbines or gas engines, small gas projects may be worthwhile. This report deals with small gas projects as a separate case.

1.14 For all four cases, it is easy to see that developing a commercially viable natural gas project—whether based on domestic gas consumption or export of gas—requires a gas source with a reasonably high flow rate. This source must also be at a reasonable distance to a reasonably high and reasonably highly concentrated, paying gas demand. Countries must decide what is "reasonable" by looking in greater detail at the economics of the project.

1.15 Toward that end, an analyst should make a first "guesstimate" of the following main elements:

1. *Gas production.* This relates to capacity, volume and the resulting costs of gas production, and possibly to any penalty for gas flared or costs of gas supply in case of import.
2. *Gas transportation.* This is the distance to market, offshore and onshore, using generic formulas to estimate cost and capacity as a function of the pipeline diameter.
3. *Main potential for consumption (volume) in urban and industrial areas.* This might be very roughly estimated on the basis of the size of the population to be served by gas by comparing the specific gas demand of countries with a similar climate and GDP per capita.

1.16 In a more sophisticated approach, one would look in greater detail at the potentials of various sources of demand—that is, markets—for gas and the replacement value of gas in those applications:

- *Electricity generation.* The potential for additional electricity demand can be approximated as a function of population and GDP (growth), less existing electricity generation. When looking for the potential gas supply to the electricity sector, one must add the potential to convert existing electricity generation infrastructure so that it can use gas as a fuel. However, this potential will and should only be supplied by gas if gas is competitive. The replacement value of gas will then be derived so that the electricity produced can compete with the best available alternatives for electricity production.
- *Ammonia production.* This might be domestic demand for ammonia or for export the value of gas is given by calculating back the price for the gas at which the costs of the ammonia produced do not exceed the market price for ammonia.
- *Other domestic uses en route.* Potential gas markets in a developing country could include industry, commerce, households, and vehicles. In addition, gas markets could include schemes for ore reduction or carbon black.

1.17 In most cases, the analysis of potential demand and the resulting earnings will very likely indicate the importance of developing an adequate market for gas in power production as a base for making the project fly.

1.18 Given the rather complex competitive situation for gas, especially in power generation, an order-of-magnitude calculation may help to provide a first impression of the economics of a gas project. A thorough analysis of the specific cases is necessary, however, before one makes a commitment.

1.19 One may need to compare production and transportation costs of gas with the netback potential for gas from given marketplaces in several iterations or variations before coming to a final judgment. The gas flow from a given gas source or the gas demand of a marketplace considered may be too small and therefore may result in a gas pipeline with a small diameter and too-high specific transportation costs. Including other nearby gas sources or gas markets or additional customers (possibly with incentive pricing) in the project may increase the project's viability, given the economies of scale of transport costs that derive from enlarging the pipeline diameter. Or, it may also be possible to isolate an economic subproject from a large, uneconomic gas project if this subproject implies a source and a consumer within a much shorter distance of each other compared with the distances involved in the larger project. Although such small projects may not make use of the full potential of a gas source, it is better to have a small, economic project than a large, uneconomic one. Moreover, the small project also helps the participants gain experience with the gas industry, which over time may contribute to reducing costs and utilizing larger amounts of gas.

2

The Economic Viability of Gas Projects

2.1 An assessment of the economic viability of a gas project has three basic aspects. First, one must determine the project's costs, preferably using a methodology based on an international cost comparison, to evaluate the benefit of the project to the nation as a whole. Second, one must clearly anticipate the price of gas for end-users, again in the context of international alternatives. Last, the *netback value* of serving different types of customers—such as power plants versus households—must be calculated carefully, as this will provide an important guide to the appropriateness, strategy, and timing of gas development.

Methodological Issues

2.2 Ascertaining what effects a proposed gas project would have on the economy of a nation requires a detailed analysis. With regard to costs and benefits, that analysis should determine the costs of the gas project, using international prices of the components as a basis. These components include the equipment, such as a gas production platform, transport and distribution pipelines, and equipment to utilize the gas (such as a CCGT). They also include the international costs of securing financing and mitigating risk. The benefits of a gas project should reflect the international market prices of the products, such as ammonia. Or they should reflect the international market prices of the alternatives to the gas project such as the replacement values for oil products, the costs of alternative power plants, and the costs of the alternative fuels used (e.g., the costs of coal-fired power plants). In such an approach, goods and services should be priced at international market prices under two conditions. First, of course, a viable international market for the respective good or service must exist. Second, the international price should be used wherever in using a good or service the country would either incur costs or forgo revenue at international prices.

2.3 With regard to international prices, suppose, for example, that new, gas-based electricity generating capacity is proposed in a situation in which this capacity could alternatively be provided by new hydropower capacity. In this case, the costs of electricity produced from a hydropower plant should be compared with the costs of increasing gas production capacity and building a gas-fired power plant. Thus, components that must be procured on the international market must be priced at international market prices. That is, on the hydropower side, this would include the engineering, hydro turbine and casting, the transformers, and the cables to bring the power to the points of consumption. For gas-based power generation, it would include the international prices for drilling wells, gas pipelines, gas turbines, and transformers. Local prices could of course be used for the costs of domestic labor or locally produced materials such as cement. In this calculation, country-specific elements would be the costs of local labor

and the geographical conditions (such as the location of hydro potential and the gas reserves in relation to the main population and industrial areas). Taxes do not play a role in this analysis, as they deal with distribution within the country. In practice, however, the choice between the two alternatives will be influenced by taxes if different tax regimes are applicable to the alternatives, as this might distort the choice between the alternatives.

2.4 In principle, as well, the externalities—to the extent that they affect the country—must be included in the analysis. This would include, for example, an analysis of the damage done by pollution linked to the use of a specific energy. The negative effects of such indoor and outdoor pollution on human health, on crops, and on buildings and infrastructure can be assessed and then valued. Although it might seem bizarre to monetize human suffering to the point of death from pollution, it would be cynical not to take into account the negative effects of pollution at all when making decisions. Air pollution is a prominent, though not singular, example of environmental damage caused by the application of energy. The list would also include use of landscape, noise, warming of rivers, poisoning of the soil through deposition of toxic ash, and acidification of soil and lakes from acid rain. Externalities linked to the use of energy, especially noncommercial energy, would also include the time spent by women and children in collecting biomass that prevents them from pursuing education and obtaining health care. An important role for the state is to find ways to internalize such externalities—for example, by taxes or incentives or by creating standards to curtail negative external effects.

2.5 Global externalities, such as a gas project's contribution to mitigating levels of greenhouse gases, may also be considered in the developing country's analysis of the project's desirability. Precise values are difficult to ascertain for such externalities, however, and, at least for the time being, developing countries have tended to consider global issues primarily in conjunction with support from the industrial countries and multilateral institutions such as the Flexible Instruments under the Kyoto Protocol. Because methane has substantially greater greenhouse effects (20 to 40 times stronger) than carbon dioxide, the positive effects of using gas can easily be offset by leakage during production, transport, and other handling. That can be avoided by using state-of-the-art techniques.

2.6 In any case, if a project is economic according to international cost standards noted above, then it is beneficial for the country. Occasionally, it might still be wise for the country to keep the gas in the ground and to wait until a higher return for the gas can be realized.

Comparison with International Gas Prices for End Users

2.7 The replacement value is ideally determined by the international market value of the substituting fuel and the international cost difference between the devices for using the gas and the devices for using the substitute fuel. As a supplementary analysis, one might look at gas prices achieved in the various sectors in regions with free-market economies. However, when looking at European prices achieved in the end-consumer market, one should adjust them for all kinds of taxes and levies before one evaluates their applicability to the economics of gas in other countries. That is because European countries have taxes not only on natural gas but also on the competing fuels. Household customers are ideal targets for national and local governments to raise money. That is why governments tend to tax them more heavily than they do industrial customers. In general, however, governments will try to tax gas in the different sectors in a way that makes the tax on gas per energy unit is comparable with the tax on competing fuel oils.

2.8 When looking at international gas prices, one must pay attention to the price levels of competing fuels, as they will constitute a limit for competitive gas pricing. In addition, in most developed gas markets, the seasons play a role in gas pricing, whether by creating higher demand for heating in winter in some regions or by creating additional demand for peak power to run air-conditioning in summer.

2.9 Comparisons with gas prices from other regions should be applied with some caution, but they can serve as a check on the order of magnitude of the level of the gas prices.

Netback

2.10 When analyzing which sectors should be supplied by gas, one should be guided not only by the replacement value of the gas but also by the difference in the costs of serving the customers of the respective sectors. For example, the replacement value of gas for the household sector, which is usually the price of LPG or light fuel oil, looks more attractive than the replacement value of gas for power generation, which might be as low as the price of coal. That picture may change, however, once one accounts for the extra costs of distribution, metering, load management, and backup necessary for the supply of gas to the household sector compared with the cost to supply gas to base-load power generation, which is basically the cost of the high-pressure transmission system.

2.11 In order to take care of both the different replacement values and the different costs related to the different applications or sectors, the concept of *netback value* may be helpful. The replacement value of gas would than be reduced by all the costs upstream in the gas chain that have to be allocated to supplying the respective sector to a point where differences in location and load structure can be neglected. This may be the point of production, the import point, or the point on the downstream side of the high-pressure pipeline before any branching off. These values are the netback values or *netback prices* at the respective points in the gas chain. The cost allocation for commonly used infrastructure is always to some extent arbitrary; nonetheless, netback prices may provide a good clue as to the most interesting sectors or applications to develop.

3

The Supply Side

The Reserve Basis

3.1 The reserve basis is not set in perpetuity but rather will develop over time as a function of exploration efforts.

3.2 For gas, the location of reserves with regard to the relevant markets plays an important role because of the transport economics. Likewise, the size of a find with regard to reserves and production capacity is decisive in determining whether the gas can be exported to distant (i.e., nondomestic) markets. If gas volumes are very large (starting at about 200 bcm), they may even justify an LNG export scheme.

3.3 Gas trade has a limited share of world gas consumption and is restricted to large-scale projects via large pipelines or as LNG to countries that use very high volumes of LNG. Options involving LNG especially costly, so they are not likely to make an imminent contribution to developing gas in small or emerging markets. The challenges LNG costs pose for an export project are well demonstrated in the example of Nigeria, which took more than two decades to realize LNG exports.

3.4 Projects such as using the gas for ammonia production or for ore reduction may be economic based on smaller volumes, as long as the specific gas production costs are low.

3.5 A way to improve the reserve situation would be to encourage contractors to undertake the additional exploration needed to bring proven reserves to a level at which development becomes an economic option. Part of that process may be to search systematically for a reliable development partner. For the development of already proven reserves, one might concentrate on those closest to a market, so that the transportation costs might be low enough to make smaller projects feasible.

3.6 Another possible way of enhancing the economic marketing of gas would be to look for additional reserves in the vicinity of gas reserves already proven but too small in themselves to justify a commercial gas project. Bringing these reserves into play might result in higher possible production rates, which then—because of the economies of scale of the transport of larger gas volumes—might economically justify a project with a longer distance to a market. That is, the additional production would justify a project that would not be feasible with a smaller rate of gas production. This assumes, of course, that that the paying demand of the markets is large enough to absorb the larger volumes of gas.

Production Costs

3.7 The important determinants of specific production costs are, first, the absolute costs to establish reserves and to install and maintain production capacity, and, second, the possible flow rate, which is a function of reservoir characteristics, size, and pressure. The quotient of both then determines the possible lowest specific costs.

Determining Absolute Costs

3.8 The absolute costs of production comprise mainly the investment costs for exploration and the installation of the production facilities at the start of the project. Also included are maintenance, insurance, labor costs during the operation of the project, and the ultimate expense of dismantling the installations. Such costs are basically independent of the actual gas volumes produced but are linked to production capacity, whether used or not. A good first approach to deal with the absolute costs of the capacity installed is an *annuity approach.* This approach assumes that the capital invested is paid back over the project's lifetime, whereby the sum of amortization and interest payment is kept constant. It also assumes that annual costs such as maintenance, staff, and insurance, can be estimated as a percentage of investment. For capital-intensive investment, an annuity of about 20 percent seems to be a good first guess. For more sophisticated analysis one would apply some variant of a Net Present Value analysis. It has to be emphasized that the economics are especially vulnerable to long buildup phases, mostly driven by a slow buildup of the gas market.

3.9 When determining the absolute costs one has to deal with the following questions:

- *Exploration costs.* In principle, exploration costs should be included, as exploration is necessary to maintain the levels of proven reserves as they are consumed and possibly to enhance them. This usually includes not only the costs for the reserves proven but also the costs of the dry wells within the country. These considerations should be included in the design of production-sharing agreements, levies, and taxes. For a given gas find, these questions may be subject to individual consideration, and it may be reasonable to develop a project even if not all the costs of earlier exploration are fully covered. This approach might be a reasonable one for gas in areas whose market is not able to recover the (sunk) costs of exploration wells and might even be shared by the oil companies. However, it might diminish the attractiveness of the country for further exploration.
- *Associated versus nonassociated gas.* In the case of associated gas, the question arises of cost allocation between gas and oil. No standard method of allocating costs to oil and gas production exists. One approach might be to allocate the overall costs in proportion to the energy produced. A more sophisticated methodology would be to try to allocate individually the costs of single components that are gas- or oil-specific and to allocate the rest of the costs according to the energy produced. Still another approach might be to attribute all costs to the production of oil if the gas is considered a product that cannot be marketed. This is not as unusual as it might at first seem, as countries may impose penalties to prevent environmentally harmful flaring of gas, and cost of the gas under such circumstances could even be considered negative to the extent that its extraction and marketing saved the expense of penalties. Gas from fields in many developing countries (including most in SSA) are developed as a "troublesome" by-product of oil production, so it may well be reasonable to consider gas as a by-product that carries no costs of production.

- *Gas fields with high contents of gas liquids.* Many gas fields have a substantial content of gas liquids, mainly propane and butane. These components can be marketed separately (e.g., as bottled LPG, which earns a higher value per unit of energy compared with natural gas). One might therefore consider investing in the separation of those gas liquids, as that may improve the overall economics of the gas field.
- *Greenfield versus expansion.* All other things being equal, a greenfield development will be more costly than an expansion for which the main infrastructure is already in place. In the case of an expansion project, the question of cost allocation can become complex. From the point of view of a national economic evaluation, which disregards how the actors share the total benefit, it makes sense to allocate only the costs of bringing new production on line to the new project. But this will not make good commercial sense if the partners in the existing infrastructure and the new infrastructure are different. The new partners would benefit from the prior establishment of infrastructure and market, and the owners of the existing infrastructure would justifiably claim compensation for their earlier investment and the risk linked to it.

Apart from the questions of how to allocate the costs, which are subject to a degree of subjective judgment, the various costs (such as costs of drilling, platform, and treatment equipment) should be established with the degree of precision appropriate to the stage of the project and the budget.

3.10 Developing offshore gas is obviously a more expensive proposition because a platform or a vessel is needed to support the wells, or costly underwater technology must be applied. The cost will increase, in addition, with the depth of water at which the gas is located and the distance from shore. Moreover, some parts of the reservoir might not be reachable from a single platform, possibly implying the expense of an additional platform if it is decided that the remote parts of the reservoir should be reached and drained. (Sophisticated horizontal drilling techniques now make this less of a problem than formerly.) Finally, one must consider the investment in the pipeline needed to land the gas. Obviously, no usable or marketable off-take is possible en route from offshore pipelines, and the physical installations are also more costly per unit of distance than an onshore pipeline.

Flow Rate Capacity

3.11 The flow rate capacity of a field is mainly a function of reservoir characteristics, size, and pressure. Because natural gas is so much less dense than liquid oil, it has the economic disadvantage of carrying much higher costs for handling, transportation, and storage per unit of energy, which makes the marketing of gas that much more difficult than that of oil. On the other hand, because of its gaseous state, gas has comparatively better flow properties in the reservoir than oil. Gas reservoirs with the same energy content as oil reservoirs therefore tend to have a higher energy flow, which may compensate for the disadvantage of gas' higher transportation costs. Apart from the characteristics of the reservoir, the overall flow capacity is itself a function of the investment. This depends on the number and diameter of wells drilled and the type of well (e.g., horizontal drilling improves the flow capacity of gas wells by tapping a wider gas-prone area and by preventing water infiltration and lower pressure differentials caused by vertical drilling into the reservoir). Again, the costs of the production capacity have to be assessed with the degree of precision appropriate to the stage of the project and the budget for it.

3.12 The annualized costs divided by the flow rate capacity give an estimate of the minimum specific production cost of the gas. The actual average production costs for the gas depend on the average flow rate, which depends on availability of the infrastructure and on the market-driven supply. These

specific production costs can be reduced if the flow rate can be increased, even if the reservoir is then depleted sooner. The increase in production capacity is usually larger than the increase in annuity stemming from the higher investment and shorter project lifetime.

4

The Demand Side

4.1 With gas, as with any other product, however well one manages the technical challenges of production, one must also have a paying demand for the product. The examples of Europe and North America show that demand for gas is well developed, as gas has a share in primary energy demand of 20 to 25 percent. The components of the demand for gas—the extent of demand and the price that can be expected in different sectors—are highlighted later in the chapter. In the meantime, keep in mind that for gas the transportation costs are often more than the price customers are prepared to pay—in many cases, much more. In this respect, gas is unlike many other goods, whose costs of transport to market are small compared with their own value. Thus, for gas, the transport costs are a critical element of an analysis of supply and demand. Because of the very high economies of scale of gas transportation in steel pipelines viable gas projects usually have a minimum size of several 100 million m^3/year. This rule of thumb may be modified in a special, often overlooked case that has shown some encouraging results: small-scale gas schemes, which may be applied locally (see also chapter 6).

4.2 Because the costs of transporting gas are so high, it makes a difference where the value of the gas is realized—the closer to the source the better. Realizing the value of the gas in the country of production keeps key benefits of gas—mainly the value of substitute energies but also savings on externalities of environmental and efficiency advantages—in the country of production. International investors producing and marketing gas that is consumed in the country of origin will ultimately want comfort that they can repatriate a substantial part of that value of the gas, even if their incentives to reinvest into the country may be high as well.

4.3 The situation is inverted in the case of an export scheme (direct export of the value of gas as LNG or via pipeline or indirect export of the value of gas by the export of gas-intensive products). Here, the value of the gas is realized on an international market, so repatriation of capital invested and profit earned is not a problem for the investor, provided the scheme is economic. The benefit for the producing country would then be the part of the rent captured by the host state (by production-sharing contracts, license fees, and taxes). It would also include the domestic economic development that might be triggered even by an export project, and the opportunity that a domestic gas industry might be developed by using part of the existing export infrastructure at marginal costs.

Realizing the Value of the Gas in the Country of Production

4.4 The following questions must be considered:

- Is there a high enough paying demand for gas? These would include assessing the volume, buildup of volume, and competitive price of the demand.
- Which sectors could be developed as sources of gas demand?
- In which sequence can they be reached?

4.5 One basic fact is that gas always competes on various terms with different energy carriers in all end uses, and other energy carriers can always substitute for gas at reasonable cost. When determining or projecting demand for gas, one must bear in mind that demand for gas is not highly inelastic, as is demand for electricity. Demand for gas is only realized when the use of gas is less expensive than the use of substituting energies or is priced at a similar level but otherwise considered advantageous. For each application of gas, the maximum of the market value that gas can reach is defined by the costs of using substitute fuels. Assuming that oil products can be made available everywhere and that domestic oil prices are not distorted by price setting by the government, an upper limit to the value of gas linked to world market prices is defined for gas. A lower limit to the value of gas could even exist when it has to compete with less expensive fuels such as coal. To that extent, gas, unlike electricity, has no captive customers. The demand potential that gas might realize for each application depends on gas being offered at a price at which it offers a clear advantage for the customer. If gas is offered at competitive prices, it has a good chance of realizing most of the potential demand, but this usually cannot happen without a good marketing effort that addresses the customers' concerns beyond price.

4.6 The best use of natural gas in developing countries is usually for electric power, which has the largest potential as a market for substantial volumes of gas. Apart from the environmental benefits, modern combined-cycle systems or even gas turbines have high efficiency and typically strong economic benefits. In fact, it was the power sector that played the role of locomotive for demand in industry and in the residential and commercial sectors in European gas markets. This was so even at a time when gas-based power generation was not yet as superior in electric efficiency and costs as it is today. The main focus of this chapter is therefore on the use of gas for power generation. Industrial use as boiler fuel or for process purposes is usually viable, if trunkline gas is close to the industrial market. Commercial and residential use of gas is so far usually not economic in Africa, because of low incomes and restricted need for heat and hot water (the exception may be South Africa).

Power Generation

4.7 The potential for using gas in power production is crucial in most cases to get a gas industry started, because even a single power plant can absorb high volumes of gas. Four principal types of gas-driven power plants are in operation today:

- *Gas-driven engines.* These range from 10 kW to 1 MW in size. Their electric efficiency is in the range of 30 percent (meaning that for the equivalent of 100 kWh fed into the process, 30 kWh of electricity are produced). The rest of the input energy is transformed into low-temperature heat, which can only be used for local heating purposes or would otherwise merely heat up the ambient air or some cooling water. (The economics of using gas for small-scale power generation are considered later in this chapter.)
- *Gas turbines.* Gas turbines may range from 1 MW to 250 MW and have an electric (nameplate) efficiency of between 30 and 40 percent). Nameplate efficiency relates to normal conditions (sea-level altitude, and ambient temperature of 0 degrees Celsius) and to the turbine running at the best point. Higher altitude and temperature lead to lower efficiency of gas turbines, which can be assessed. Also degradation effects between maintenance and not running at the best point all time due to load variations may result in a loss of efficiency of up to 2 percentage points. For economic evaluations these discounts on the manufacturers guaranteed nameplate efficiency should be discounted appropriately. Nowadays, gas turbines are available in predetermined sizes, as the manufacturers standardize and prefabricate the turbines to reduce costs. Gas turbines have several advantages. They are small, so they can be easily and swiftly installed, and they need little maintenance. Moreover, they are available at the lowest costs for the capacity installed (less than $400/kW installed). They also do not need an infrastructure linked to water for steam and cooling.
- *The classical steam condensing power plant fired by gas.* This consists of a boiler that generates steam that is expanded through a turbine and is then condensed. The electric efficiency is between 35 and 45 percent. Condensing power plants fired by gas are no longer common because their investment cost is much higher than that of a gas turbine, and they require much more maintenance. In addition, the advantage of steam condensing over gas turbines in efficiency is no longer very large. Finally, condensing plants in warmer climates tend to have significant problems with corrosion that can severely limit the availability of the plant.
- *Combined-cycle gas turbines (CCGT).* These combine a gas turbine with a steam turbine, in which the exhaust air of the gas turbine (still very hot, at about 500°C) is used to generate steam to drive a steam turbine. CCGTs now reach up to 58 percent of electric (nameplate) efficiency .The reasons given for de facto efficiency being lower than nameplate efficiency mentioned for the gas turbines apply also to CCGTs and should also be taken care of in economic analysis. The investment costs for CCGT are very attractive; at the end of the 1990s, these are as low as $400/kW installed, compared with $800 to 1,000/kW installed for coal-fired power plants with state-of-the-art exhaust air cleaning. Prices for CCGT have gone up recently to about $450 to $500/kW installed, however, because of high demand for gas turbines and CCGTs. Depending on the price of gas, it may be more economic to invest in gas turbines, as they require a lower

investment. It may in fact be sensible to invest first in the gas turbine part of a CCGT and then add a steam turbine later on, when gas becomes more expensive.

4.8 In view of the corrosion problems that seem to haunt steam schemes in tropical areas, gas turbines may often be the better solution, despite their lower efficiency. That lower efficiency would count for very little, in fact, if the plant used gas that otherwise would have been flared. Another point favoring gas turbines is that the specific investment for them is lower. When looking at the replacement value of gas in power generation later in this chapter, one should keep in mind that all of these power plants could also run on gas oil without significantly higher investment or loss of efficiency. Modern gas turbines can even switch between gas and gas oil while in operation.

Gas Volumes Consumed in Power Generation

4.9 To illustrate the volume of gas consumed in power generation, consider the following example. A gas turbine of 100 MW that runs at an average of 5,000 hours a year at full load generates 0.5 billion kWh. At an average electric efficiency of 35 percent, the turbine would need an annual energy input of 1.43 billion kWh, which amounts to about 140 million m^3 of gas, or 140,000 t of gas oil. Thus, a few gas turbines can consume a substantial amount of gas—a feature that makes them highly useful as a base for gas development. Power generation is useful in this regard not only because of the sheer volume of gas it takes but because it represents a highly concentrated source of demand—one that can be served directly from a high-pressure trunkline. It thus does not require the costs of gas distribution. Gas demand in power generation can achieve a reasonably high load factor, and even the competitive price that gas can earn may be attractive. Power generation is also an easy-to-handle source of demand for the gas seller because the gas seller has to deal with only one or a few entities.

Replacement Value of Gas in Power Generation

4.10 When looking at the replacement value of gas in power generation, one must distinguish the case of using gas for new power generation capacity and the case of using gas to replace existing power generation in existing plants. Because of the substantially low specific investment for power generation capacity based on gas compared with other fuels or with new hydro capacity, long-run marginal costs of gas-based power generation will be competitive in most cases. However, because of lower operating costs (including fuel costs) of coal-based power and even more of hydro, the short-run marginal costs of gas-based power generation may not be competitive.

4.11 New additional power generating capacity may be hydro (when available at reasonable costs) or thermal power plants based on fossil fuels. (Renewables and nuclear are not discussed, because the former can only contribute locally and only to very limited extent because of restrictions in the producing capacity for renewable electricity generation devices. The latter is omitted because of its very high investment costs, its technical complexity, and other important problems.) When comparing the economics of alternative new power generating capacity added to an existing power system, one should compare the economics of the overall power system resulting from the inclusion of the alternative power capacity under discussion. The main reason is that different power generation capacities may end up in a different place in the merit order of the power system, mainly because of a different ratio between capacity-related costs and fuel and operating costs. Also, the potential to phase the investment for additional capacity or to create new power capacity closer to main power consumption areas may have a significant impact on the optimal choice. These considerations are taken up in various computer-based optimization programs. However, in most of the cases under discussion here, a side-by-side comparison

of alternative additional power capacity, as described below, will give a good estimate of the competitive situation of new gas-based power generation.

4.12 For gas to be competitive for new power generation, it must at least fulfill all three of the following conditions, when applicable:

1. *Gas must (on an energy equivalent basis) not be more expensive than gas oil, because gas oil could be used in the same turbine or CCGT with no basic difference in efficiency or pollution.* The only difference would be in CO_2 emission, where gas oil emits 30 percent more per kilowatt hour than gas but 40percent less s than coal-based power production. All other elements being equal, the replacement value of gas in this case is defined by the energy price of gas oil. It should be kept in mind that the decision to build a gas infrastructure entails high up-front investment that is dedicated to specific projects on the consuming side, whereas the gas oil is fungible. That is, its supply can be curtailed or redirected if a specific project fails. Installing a gas infrastructure is a one-time decision that cannot effectively be modified later on.

2. *The determination of the replacement value of gas in new power generation compared with coal-based power generation is more complex.* Here it also matters whether the comparison is with a gas turbine or with a CCGT. The main differences are as follows:

   - The difference in pollution. This is a point in favor of gas, even with state-of-the-art flue-gas treatment at the coal-fired power plant.
   - The large difference in investment. Coal-fired power plants require $800 to $900/kW installed, compared with $300 to $350/kW installed for a gas turbine and $400 to $450/kW installed for a CCGT.
   - The difference in electric efficiency. This is 35 to 45 percent for coal-fired power plants compared with 30 to 40 percent for a gas turbine and 50 to 58 percent for a CCGT, where the latter figure stands for the most advanced technology.

   The replacement value of the gas is then determined as the value at which the costs of electricity generation based on gas equals the costs of electricity generation based on coal. Given the large differences in investment (which gets even larger when the much longer construction periods for coal-fired power plants are also taken into account), the replacement value of gas compared with coal is obviously a function of the full operating hours per year. (Although not common practice, this can be reflected in a two-tiered tariff for the gas, by which the difference in annually fixed costs would be translated into a capacity charge for the gas.) At low operation hours—that is, for peak and middle load—gas will be competitive already on the basis of the lower investment for gas-based power. Even if coal is for free, gas in gas turbines is still competitive with coal in peak and middle load at gas prices of about $3.00 to $3.50/MMBtu. At the present level for internationally traded steam coal of about $35/t cif, gas in CCGTs is even competitive with coal for base load at a gas price of $3.00 to $3.50/MMBtu. (The above comparisons are based on power plants with a capacity of 600+ MW.)

   In contrast to gas, coal-fired power has large economies of scale, especially if the coal-fired plant is equipped, as it should be, with state-of-the-art exhaust gas cleaning. Because coal-fired power is most economic at large scale, the balance tips in favor of gas

in the many developing countries that are generally better served by a smaller-scale power production (this would include most of SSA). Gas or gas oil is competitive with coal for large capacities. But coal is not competitive with gas or gas oil for small capacities, because with lower capacity size the specific costs of power generation based on coal increase much more than for power generation based on gas or gas oil.

3. *Gas-generated power must be competitive with electricity from new hydro.* This is highly dependent on local factors. However, the likelihood is that hydro that is cheaper than gas has already been developed. A principal difficulty of hydro is that it may be dependent on precipitation, and the available power capacity may drop as water levels decrease. Hydro thus may need thermal backup systems, the costs of which have to be evaluated and allocated.

   When comparing with a hydropower project, the power transmission costs to the site of the gas-fired power plant have to be added.

4.13 Only if the gas price meets the above three alternatives is gas is the better solution for new power generation. The value that gas can achieve in new power is in any case the lesser of the value of gas oil and the price at which the costs of electricity production break even with a coal-fired power plant or the electricity price (competition with the grid) netted back to the gas.

Replacing Generation in Existing Power Plants by New Gas-Based Power Generation

4.14 When gas has to compete with other fuels or hydro in existing capacity, then the replacement value for the gas will hardly be attractive, as the marginal costs of other fuels as well as of additional hydropower generation tend to be smaller than the costs of gas (oil). A yardstick for comparison might also be the price of electricity traded in the grid, to the extent that such trade exists and its results are accessible. Gas in new turbines or CCGTs will hardly be attractive, as the marginal costs of other fuels as well as of additional electricity traded in the grid tend to be lower than the full costs of new gas-based power generation. However, for old power plants with electric efficiencies lower than 30 percent and high maintenance and staff costs and low availability, even the full costs of new gas-fired power may be competitive.

4.15 Gas has a potential premium in power generation for environmental reasons. The element of noxious emissions is largely taken care of, when comparing gas-fired plants with coal-fired plants with state-of-the-art environmental protection. However, even then, gas has advantages (e.g., absolutely no dust emission, as even state-of-the-art coal-fired power plants cannot outperform the low exhaust levels of CCGTs), advantages, which are not reflected in the above calculations and considerations.

Competition between Gas and Electricity for Transport and Distribution in Emerging Markets

4.16 When looking for gas for power generation, a first point is to compare the costs of a gas fired power plant a given place with the costs of alternative power generating or supply schemes.

4.17 In many cases, power generation based on gas will be integrated into an existing power system. This implies that a new power plant will usually be connected to the existing power grid so that the energy created is transported as electric power in an already existing grid with sufficient capacity or inexpensive to extend. However, especially in emergent markets, the infrastructure on the gas as well as on the electricity side may be up for development and therefor for considerations how to optimize the

overall system. This implies, that after the a.m. cost comparison a second one should be done: A comparison, whether the costs to supply electricity based on gas could be lowered by changing the point where the gas is transformed into power. With present technologies (based on AC transmission) the transport of gas will tend to be cheaper for large systems than the electricity transmission. This may not be true for smaller projects and depends in any case on the specific geography of the country such as the soil conditions, number of river crossings, and so on. So it may be worthwhile to investigate this point because this may improve the case for applying gas.

4.18 A similar question arises when it comes to distribution. To what extent should the gas distribution grid be build or extended in competition with the electric distribution grid? This, of course, creates competition in the transport/distribution of energy between gas and electricity. It implies, as well, that an expansion of gas grids, combined with smaller, more localized power generation units based on gas, will compete for markets with additional centrally located power generation and the implied enforcement of an expanded central electric grid. This is an issue of particular interest in developing countries in which expansion of the central electric grid may not happen in incremental steps and may necessitate large grid expansions that can be avoided by the development of localized power generation with semi-autonomous grids. Compared to the issue of alternative transmission as gas or as electricity, which is basically determined by the relation between the transport costs, in distribution also the economies of scale of large centralized power generation vs. decentralized power generation with loss of economies of scale have to be considered. Of course, expanding the gas grid with additional small gas-based power generating units also offers more opportunities to augment the total demand for gas as the gas reaches larger areas.

4.19 Coal fired power plants have high economies of scale, especially if they have state-of-the-art flue-gas cleaning. This favors power generation in centralized units. The economies of scale for gas-fired (and gas oil–fired) power generation are much less, meaning that power generation in smaller units is almost as favorable as in larger units, thereby favoring decentralized power generation. In any case, it may be possible to save on electricity distribution costs because of potentially lower gas distribution costs, less the loss of economies of scale.

4.20 In colder climates, decentralized power generation in smaller units makes it possible to make optimal use of cogeneration. In cogeneration, the relatively low-temperature exhaust heat of the electricity-generating process, which would otherwise be wasted into the ambient air or water, is used in thermal industrial processes or for heating purposes (heat sinks). The ratio between power output and heat output of cogeneration plants is between 0.5 and 1, and the plant uses 80 to 90 percent of total energy input. (At this rate, the energy waste is really confined to unavoidable technical losses.) Hot water or steam can be distributed economically only within a very limited radius—a few kilometers at most—so the demand for heating or steam must be local. Refineries need steam and heat in the order of 100 MWth and more. Practically all other heat sinks are on the order of 10 MWth or less. (This applies also for district heating, which loses efficiency if areas supplied require more than a few MWth, because the average supply distance then becomes too large) Using smaller decentralized cogeneration can therefore serve heat sinks in a tailor-made way. (Although a 100 MW plant can of course also coproduce the heat of 10 MWth, it would than waste a large part of the energy via a condenser, which would warm up the atmosphere or local rivers.)

4.21 A further element that should be taken into account in assessing the potential market for gas is the load factor of the demand for the gas. Low load factors of electricity demand caused by seasonal or economic variations in power use imply investment into high capacities all along the gas

chain. Only small gas volumes will be marketed, and therefore the specific costs for the gas will be high—possibly far beyond the prices for the substitute for gas, which define the limit the gas consumer is prepared to pay. When load factors are low, the existing investments in high capacity all along the gas chain will require high expenditures for operation, maintenance, and amortization of debt but with little income to compensate. That is, in an industry such as gas, with a relatively high proportion of the investment in fixed costs, those costs depend heavily on installed capacity, not on volume, so that lower volumes sold do not cause any substantial relief on the cost side. That may make the use of gas less economic. The dilemma is the overwhelming cost of the capacity to make the gas available, independent of whether and how much gas is delivered. That is, the costs differ little whether a gas field and pipeline are run at very low volumes or at maximum volume. The exceptions are the very long pipelines, such as the 5,000-km Russian gas lines, for which the additional fuel and operating costs become significant because of the need for a large number of compressor stations along the route.

4.22 Gas-fired power stations may have to absorb the load variation of power demand directly. The reasons for this may be seasonal variations caused by climatic factors or by patterns such as the length of the working day or society-specific holidays or rest days.

4.23 A gas-fired power plant may also have to take up the variation of availability of other power plants. For example, if thermal and hydro systems are linked, the thermal power plants must compensate for unavailability of hydro in periods during which precipitation is inadequate. Thus, the variability of demand for gas should be taken into account, because it creates higher specific costs.

4.24 Estimates of potential electricity demand would usually look at population and its increase, the development of per capita GDP, and some correlation of GDP development and electricity consumption. The rule of thumb is that each additional dollar of GNP corresponds to an additional kilowatt-hour of demand. This factor is somewhat reduced in warmer climates, where space heating is not a significant source of consumption. It is also reduced in mature economies, where demand tends to level off relative to growth in GNP or GDP because of the transition to a more service-oriented economy, use of more efficient devices, and saturation with basic electricity-consuming devices. This estimated development in electricity demand can be compared with the existing electricity generation, the difference being the potential for gas-based power generation, provided the gas price is competitive. This approach might give a good first approximation of potential gas demand for power generation. More sophisticated approaches would also look at the load distribution curve of the power generation and try to evaluate the effects of a new plants on the merit order of all plants. However, as the load distribution curve in warmer countries is not so peaky, the first approach, which neglects the effects on the merit order, should give good estimates.

Industry

4.25 Gas may also be used economically in industry outside power production, especially if the industrial market is near the gas-based power generation or on the pipeline route to it, which can enable the industry to take gas off the trunkline, thereby creating only incremental transportation expenses. Gas is used in industry for different purposes, which require different volumes and different replacement values:

- *Steam raising.* The gas is burned in a boiler, where the heat of the burning gas is transferred to vaporize water and heat up the steam (e.g., in the chemical industry and in refineries). In such cases it is often economic to also produce power by a process of *cogeneration*

- *Power generation.* If an industry is interested in producing its own power for reasons of independence or lower costs, gas may be an appropriate solution. The replacement value of gas is then determined in a way similar to power generation—that is, by comparing the cost with that of the fuel that otherwise would have been used (e.g., heavy fuel oil).
- *Chemical plants and refineries.* Chemical plants and refineries use gas mostly for steam raising and power generation. They are particularly noteworthy because of the large volumes of gas they may consume annually: a chemical plant may consume several hundred million cubic meters and refinery about a hundred million cubic meters.
- *As a raw material or feedstock.* The main uses of gas as a raw material or feedstock are to produce urea and ammonia. Assuming here that the production of ammonia is not intended as a means to export the value of the gas, the required volume of gas will be a function of the domestic need for fertilizers. As a rule of thumb, 1,000 MMCF of gas are needed for 1 t of ammonia. When calculating the value of the gas for ammonia production, one would have to take the world market price of ammonia and deduct the production costs apart from the gas. The result of such a calculation is given in Table 4.1 at a value of 0.9$/MMbtu. If that does not cover the cost—at least the marginal costs of producing and transporting the additional volumes of gas to the ammonia plant—then it is better to import the ammonia. (The exception to this rule would be if building and operating the ammonia plant would trigger a gas development with a substantial upside potential for later developments.) The other applications of gas listed in table 4.1 should also be considered, although the values given in table 4.1 should be used with some caution, as there might not always be demand for additional capacity in the respective areas.
- *As direct process heat.* Here the heat developed by the burning gas is applied directly to the material to be treated. Gas has the advantage over other energies that the flames of gas burners can be very precisely directed and applied in precisely measured doses. This is of great advantage in glass smelters, for example, where the heat must be very evenly applied to avoid later cracks in the glass. It is also useful in brewing, where precise temperature should be kept. Other applications would be drying processes (e.g., for all kind of food production). The next-best alternative fuel for such processes is LPG or gas oil. That implies that the replacement value of natural gas in such applications is high. The volumes typically consumed, however, are not so high. They range between a million and several tens of millions of cubic meters per year.

4.26 Once a gas development seems economic (e.g., it has demand from power plants as a base market), it may be a good idea to try to attract some of the industries mentioned above. This assumes that these industries are in the neighborhood of the power plant a gas pipeline and are thus able to make use of the nearby gas and to realize the upside potential for the country to enhance profit by creating more value than costs. (This is a purely economic evaluation, so the details of the sharing of this extra revenue are then subject to the commercial terms on which the project is arranged.)

Table 4.1 Gas Values of Various Processes

(Localization Factor 1.3 Relative to the U.S. Gulf Coast)

Type of production	*Daily production (t)*	*Annual gas consumption (bcf)*	*Lifetime gas consumption (tcf)*	*Gas value ($/MMBtu)*
Iron reduction (new)	2,900	12	0.3	2.9
Carbon black	120	2.4	0.06	2.3
Dimethyl ether	4,300	65	1.6	2.2
Iron reduction, Midrex	2,900	11	0.3	1.9
Dimethyl ether	1,800	27	0.7	1.6
Methanol	2,500	27	0.7	1.4
Methanol offshore	1,500	16	0.4	1.0
Gas-to-olefins	2,400 ethylene	120	3.0	0.9
Ammonia	1,800	20	0.5	0.9
Methanol	1,500	16	0.4	0.7

Note: The *localization factor* is the factor by which the capex on the U.S. Gulf Coast must be multiplied to estimate the capex at the gas field. Midrex, a process of the Midrex Corporation, is the most commonly used DR method, using natural gas (and no coal or coke) as the only energy carrier and reducing medium. bcf = billion cubic feet; tcf = trillion cubic feet; t = metric tons.

Source: Reproduced from ESMAP 1997 (Report 201/97, "Commercialization of Marginal Gas Fields").

Residential and Commercial Sectors

4.27 Even in warm climates, gas can often be economically used in hotels, airports, hospitals, administrative buildings, and concentrations of restaurants and shops. This is particularly the case if the gas is used for the combined production of power, warm water, and air-conditioning. As the electric power needed would range from 100 kW to 1 MW, the gas used would be between 100,000 m^3/year and 1 million m^3/year. The replacement value is high, as the gas would replace LPG and electricity, unless the price for electricity from the grid is cheap. Such a development would presuppose that gas development is already taking place and that the distance to the nearest gas pipeline is not too great.

4.28 The economic use of gas in households depends strongly on climate. In warm climates, gas would only be used for cooking and water heating. Using gas for cooking may improve indoor and outdoor pollution substantially. It would then replace LPG as the next clean fuel. In a mostly tropical context, however, the expensive metering system used in the gas systems of industrial countries is not likely to be cost efficient because its costs would not be covered by the more restricted use of gas—that is, the lack of need for space heating. Similarly, any scheme to distribute gas at the household level will also have to mitigate the expense of individual distribution—perhaps by using inexpensive polyethylene pipelines. Again, this would presuppose that other, larger users are driving the gas development and that the distance of any local distribution network to a major gas transmission pipeline is not too large. As the figures in chapter 6 suggest, it may in fact be practical to connect some commercial entities and some households to gas if they are not too far from the main gas pipeline, once the industry as a whole has taken off.

Vehicle Fleets

4.29 Compressed natural gas (CNG) can be used in vehicles (particularly urban fleet vehicles) with some significant advantages. To begin with, using CNG vehicles can help reduce local emissions in highly polluted cities. In addition, they use national resources in preference to imported and presumably pricier petroleum products. From a practical standpoint, using CNG for vehicle fleets has the advantage of exploiting a well-known technology that is already in extensive use in Italy, the United States, Canada, and New Zealand. Moreover, although CNG runs well in specially designed vehicles, it can be used in existing units with the help of available retrofit kits.

4.30 On the minus side, because of the low energy content of CNG per volume, the reach of CNG-powered cars does not approach that that of gasoline-driven cars. The vehicles are also limited in range by the need for specialized filling stations. CNG cars thus make sense for fleets in well-defined geographical areas, assuming the affordability of the capital costs of distribution and extra costs for converting vehicles.

4.31 On the whole, the number of vehicles and the total volumes of gas consumed for vehicle fleets are likely to be small relative to other sources of gas consumption, and, as a marginal market with low volumes and a low netback, they are unlikely in themselves justify a gas project. A gas driven car would use about 1 m3/km. Nonetheless, they may contribute to the reduction of air pollution in cities with heavy traffic and represent a nice upside potential for a gas project that is economic for other reasons.

4.32 A final, more technical, point is worth noting. Planning for the use of CNG-powered vehicles requires attention to the *methane number* of the gas used. A methane number has implications for gas engines that are similar to those of an octane number for gasoline engines. The methane number reflects the content of methane in relation to higher hydrocarbons. It may vary from field to field and thus may affect the utility and economics of the CNG as a fuel for vehicles. Again, an ultimate problem with the use of gas for industrial/commercial production for the domestic market is the question of exchange rates and of convertibility for repatriation of profit to foreign investors.

Realizing the Value of the Gas in Export Schemes

4.33 Exporting gas realizes its value in the international market, outside the producing country. This is desirable for countries with high gas reserves for a given level of domestic demand and is thus an option frequently sought by gas-rich states with low populations, such as the Gulf States or Norway. Export of gas can be accomplished by selling the gas as such through an export pipeline or by marketing it as LNG. In both cases, this is costly because of the low energy density of gas. An LNG project is economically feasible, by rule of thumb, for reservoirs with at least 200 bcm of recoverable reserves.

4.34 A second option is to find exportable products that are able to absorb a large part of the value of the gas. The value of the gas might also be exported in the form of ammonia, methanol, carbon black, or by ore reduction (see ESMAP report 201/97). Whereas exports of fertilizers from abundant sources of cheap gas have proved economically viable, the economics of all other cases have proved to be difficult at least, and no outstanding economically successful examples have emerged so far. Although none of these has achieved the level of a real breakthrough, various other schemes are contemplated for building the value of gas into a more transportable product. For example, some companies are optimistic of developing the gas-to-liquid process within the next decade to a stage where they can produce clean

diesel from small and large gas fields at costs competitive with producing diesel in a traditional oil refinery. Such a clean diesel would have both the cleanness of gas and the easy handling of a liquid. Apart possibly from costs, the only disadvantage compared with gas would be the higher CO_2 emissions linked to the production and consumption process for clean diesel. Table 4.1 gives an overview of the volumes of exportable goods produced, the volumes of gas needed, and the gas value. These figures are merely indicative, however. Any serious project must investigate these options thoroughly to determine and whether a demand exists for the goods so produced at the prices assumed in the study on the world market.

4.35 Ammonia constitutes a special case of a good produced from gas, as it might also be used in the country. However, if other domestic or export markets are available for the gas, it may be more economic to direct the gas to these higher-value uses and import the ammonia.

5

Linking Production and Consumption

5.1 Linking the production and consumption of gas requires transport from the production sites in high-pressure pipelines and, possibly, distribution in lower-pressure pipelines to small industries, commercial establishments, and even households. In addition, devices or strategies may be necessary to adopt the possible or desirable production rate to the demand pattern of the consumers. These would include a capacity for gas storage, an ability to use LNG peak shavers as an alternative or supplementary gas source or arrangements with dual-fired or interruptible customers. Such customers can suspend their gas off-take because they can switch readily to fuel oil, for example, or because they are able to interrupt the processes for which they need the gas. An evaluation of size and costs of production, transport, and demand potential will show whether a basis exists for an economically viable gas project that could be commercialized. If not, one may rerun the exercise (looking for different gas supply sources and different gas markets) in an effort to find alternative schemes—or a fine-tuning of an existing scheme—that may improve the project's economic viability.

5.2 For gas, the investment in the transportation and distribution infrastructure is usually as large as the investment into the devices to use it. Thus, the gas pipeline to serve a power plant may cost as much as the power plant itself. In contrast, oil, which can be transported more flexibly, involves a much smaller specific investment in transport and distribution. Thus, compared with the loose and flexible oil chain, the gas chain is both technically and economically rigid. Given equality on a pure cost-comparing basis, the rigidness of the gas scheme may tilt the considerations in favor of the substitution fuels.

Transport

5.3 Transport capacity and the costs of the pipeline are mainly a function of pipeline diameter, inlet and outlet pressure, and pipelaying conditions (flat or hilly, soft vs. rocky or swampy soil, the need to cross rivers or canals, etc.). As a rule of thumb, capacity is proportionate to the square (more exactly the power of 2.5) of the diameter of the pipe. Capacity is also proportionate to the square root of the difference of the squares of the inlet and the outlet pressure. (For higher inlet pressures, this boils down to the maxim that capacity is roughly proportionate to the inlet pressure.) A good overview on the economics of gas transportation by pipelines, including cost estimates, is given in the OECD publication, *Natural Gas Transportation, Organization and Regulation* (1994).

5.4 Costs are proportionate to the diameter and to the wall thickness of the pipeline, which in turn is proportionate to the pressure for which the pipeline is built. Increasing the inlet pressure leads basically to a proportionate increase of cost and capacity. But increasing the diameter leads to

proportionately higher costs but comparatively greater increases in capacity. Thus, a pipeline diameter larger than needed for the actual market (e.g., building a 22" pipeline instead of a 20" pipeline) adds about 10 percent to the costs but about 25 percent to capacity. Adding the same capacity increase of 25 percent later on would cost at least 25 percent of the original costs. This implies the question of how much of a chance one is willing to take on the expansion of the gas market beyond the presently visible market potential. In any case, the transportation capacity build must satisfy at least the minimum of demand and possible production. The consequence of the foregoing is that in the planning stage, incremental transport capacity costs are cheaper than average transport costs. Once the pipeline is in the ground, transport capacity may be increased by installing additional compression or by "looping" the pipeline (i.e., laying a parallel pipeline along another pipeline for part or all of the distance of the first pipeline). That, however, leads in tendency to incremental costs higher than the average costs. The most important question when conceiving a gas pipeline system is the question of setting the pipeline diameter in a way appropriate for present and future market potential.

5.5 Unfortunately, gas pipelines are expensive, and because of the relatively low energy density of gas—even of highly compressed natural gas—the specific costs of transporting gas by pipeline are much higher than those of liquid fuels. When the costs of the transportation run as high as the costs of the fuels gas would displace, it is clearly not economic to build the project, even if the gas is free. The only case in which one might build the project then would be to realize some other benefit. That could include, for example, a later upside potential of the gas development, or the environmental benefit in using gas that would otherwise be flared, or the possibility of using domestic labor compared with the costs or opportunity costs of oil, which are always in dollars.

Load Management

5.6 Demand for gas is not even over time but is influenced by social patterns such as daily and weekly working schedules as well as by natural patterns such as temperature changes or seasonal variations in precipitation. Those influences result in short-term or seasonal or even multi-annual variations of demand for gas or its substitutes. A common yardstick for these variations (used for gas and electricity) is the *annual load factor,* which is expressed as the ratio of the capacity used on an annual average to the peak capacity used (in percentage terms) or as the number of annual hours of full load (in hours per year).

5.7 When assessing the need for transportation stemming from the gas demand (e.g., for power generation), attention must be paid to the question of load factor for the gas off-take. The transport capacity for the gas must be sufficient to cover the peak demand (e.g., by a power plant). Otherwise, some storage for the gas should be provided close to the consumer of the gas, or the gas customer must be able to satisfy its peak energy demand by fuel switching. The pipeline itself, when not used at full capacity, provides some short-term storage. That is, the difference in volume given by the full use of the pipeline and actual use of the pipeline constitutes a buffer—albeit one that probably should be calculated in terms of hours rather than days. This may cover short peaks, at a repetitive pattern, such as variations between day and night consumption. The peak fuel demand of modern gas turbines (also as part of a CCGT) may also be bridged by fuel switching to gas oil, which may be cheaper because the costs of storing a limited amount of gas oil may be less than those of a higher transport capacity.

5.8 However, when the thermal power plant system is linked to a system of hydro power plants, even in warm climates the gas demand of thermal power plants will show seasonal demand patterns. This is because the thermal power plants will have to compensate for variations in hydropower

generation caused by variations in precipitation—including not only the usual seasonal variations in rainfall but also the secular irregularities exemplified by the drought of the last few years on the West Coast of Africa. In such cases, the amount of fuel to hold in reserve for fuel switching may become very large, and a larger-dimension pipeline may be the better alternative.

5.9 An alternative to constructing a larger pipeline may be using substantial gas storage close to the market. This, however, depends on the presence of certain geological features, such as salt domes, or on the existence of old gas or oil fields that can be refilled under pressure, and is in any case costly.

5.10 Summing up, the fundamental techno-economics of gas chain require large up-front capital investments, and, as discussed above, increasing returns to scale can be achieved in the planning stage but not after the pipeline is laid. Key factors that define these characteristics of the gas chain are as follows:

- *It is subject to "lumpy," indivisible capacity expansions.* For example, pipelines come in diameters that increase by 2-inch increments; likewise, capacity increases achieved by adding compressor stations represent lumpy investments.
- *Equipment and infrastructure are to a large extent "dedicated."* A pipeline laid to supply a customer at point A cannot be used later on to supply a customer at point B if demand at point A stops for whatever reason. The same holds for a pipeline exporting gas from a specific gas reservoir. If the reservoir is exhausted, the connecting pipeline no longer has economic value.
- *Specific transportation costs are high compared with those of competing fuels.* This implies long amortization times to reduce the specific costs to a range where gas can compete.

The consequence is that in an economic sense, gas chains are rather inflexible when it comes to changing their use—be it with regard to timing or localization.

Practicalities and Priorities

5.11 As long as the development of a gas project is not economic, it cannot be forced by the best incentive schemes. The first problem for most developing countries is to provide commercial energy to their population, to give people a greater range of energy choice. Traditional kerosene—and even more so LPG—may lead to an improvement of air quality that is comparable to that provided by natural gas. Even with regard to CO_2 emissions (seldom the most urgent concern in developing countries) the use of kerosene and LPG is a large improvement over biomass fuels. Gas oil might also be a good choice for clean, decentralized, and efficient power generation. Some key points bearing on the development of gas projects may be summarized as follows:

- *Most likely, a gas project will in the beginning be triggered by use of gas for power generation, possibly together with fertilizer production.*
- *Demand for gas may develop only over time.* That is, a demand for gas may gain dominance only after a progression through several substitute fuels builds into a "critical mass" to trigger development of the domestic gas sources. That might occur, for example, through switching to natural gas from fuel oil in power generation. Or, it might come from a switch from LPG in household use, which is possible without great technical difficulties or large investment once the gas pipeline is there. Another reason

for pushing ahead with gas development is that demand for energy is considered as a function of the average national income, whose development is often hindered by insufficient supply of reliable energy and electricity. Bridging the time by using substitutes for gas that can later be switched to gas when national income and thereby demand for natural gas are high enough might also have merits against this background.

- *If a gas project is economically viable for a certain volume, it probably pays to build the pipeline 2 or 4 inches larger if the gas reserve basis is large enough.* This is because the incremental costs are not very large, but the incremental capacity thereby gained is substantial, and, if reserves and consumption are there, more consumption will follow.
- *Where countries have domestic natural gas resources, development of them in a first step aimed at export could pave the way for domestic use of natural gas.* This is the case because the relatively small additional domestic gas consumption would cause only marginal cost increases.
- *When a country is judging whether a developing a gas industry is economic, it must not only look at the total replacement value versus the cost of the whole gas chain.* The country must also consider that it faces the effects of a currency exchange guarantee for the lifetime of the project and in case of imports a long-term minimum pay obligation (which is translated into a long-term power purchase contract with a currency convertibility guarantee by the state). A currency guarantee is not an argument against a gas development by itself, as alternatives to using gas may result in a similar effect on the country's foreign exchange. However, gas schemes other than the use of fuel oils tend to obligate the state for the long term. Moreover, they leave the state with little means of reducing foreign capital spending by reducing consumption because the foreign currency is spent in a lumpy, up-front-biased project, resulting in long-term obligations. In contrast, the use of substitute fuels could be curbed in a cash crisis.

5.12 Determining that a gas project is economically feasible—that is, having sufficient production at reasonably low costs, a large enough paying gas demand, and a distance that can be bridged economically—does not automatically set a project in motion. Apart from the construction and operation of all elements of the project, the financing remains—typically through private investment. The experience of the last two decades has demonstrated that these functions are most effectively and efficiently handled by private investment. The state generally no longer plays the role of the operator of such projects, as in most cases this has proved inefficient. But the state may play a role in creating enough interest in a project (assuming that private investors are not already convinced of its commercial viability) by assessing whether a project is economic. Furthermore, the state must define the benefits for all participants—benefits that are attractive and clear to all players. These include not only the gas consumers but also the citizens of the state with regard to safety and environment, and not least the producers, transporters, and consumers and the state with regard to economic benefit. This will require a framework in which private investors in the different parts of the gas chain can operate under commercial principles. These issues are considered in chapter 7 and following chapters.

6

Small-Scale Gas Schemes

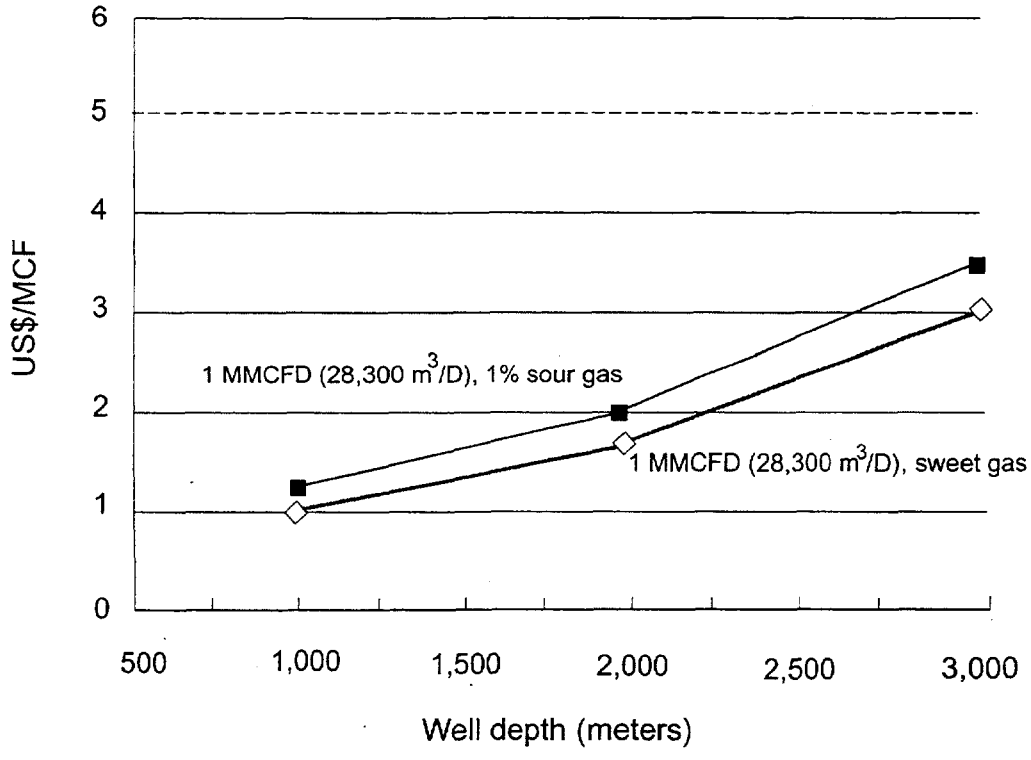
6.1 Developing a small-scale gas project requires some change in all actors' mode of thinking—for example, in widening consideration to small projects, which have specifically higher transaction costs. Those costs are often the reason that credit institutions are not very keen on financing such projects. Another element is the high cost of fuels distribution using conventional technologies and perhaps sometimes the rather conventional thinking of engineers, which may not favor unusual cost saving solutions. Also in many cases LPG or kerosene may be more economic than small-scale gas development; any of the three would be a large step forward compared with the inefficient mining and burning of biomass. Nonetheless, small-scale gas projects might still go forward through local entrepreneurs, employing local capital. Small-scale projects in developing countries also take advantage of the low labor costs for the laying of the pipelines, so that this may not be as much of a problem as it is in the industrial countries.

6.2 The issues of small-scale gas field production; transportation of small volumes by plastic pipelines; and small, gas-based electricity generation schemes are described below. The respective cost estimates are given in Figures 6.1, 6.2, and 6.3. They are based on 1995 values; since then, these values have most likely come down further. Main examples of small gas schemes are the Alberta Rural Gas Program for the supply of gas from main trunk lines to farmers' cooperatives in Canada, and the supply of gas from a well in the Pande gas find in Mozambique for small power generation schemes in Vilankulo and Inhassoro. The Pande case is described in more detail in Annex B.

Production / Source of Supply

6.3 In some cases, it may be economic to drill a development well with a low production rate to satisfy a small demand that can be reached by plastic pipelines. When is it economic to develop a gas field to supply a small project? Two principal considerations may be taken as a guide: First, the gas demand should high enough to support a production of about 1 MMCFD (10 million m^3/year). Second, the gas supply should be both reliable and inexpensive—preferably from proven reserves of sweet gas in shallow formation. Figure 6.1 shows the costs in U.S. dollars per thousand cubic feet for a well with a production capacity of 10 million m^3/year, depending on the well depth and the quality of the gas. In most cases, however, gas supplies for small projects will come mainly from transmission pipeline systems already in place. In such a case, an even smaller consumption may be economically viable.

Figure 6.1: Development Costs for a Small Gas Field, Sweet Gas versus Sour Gas

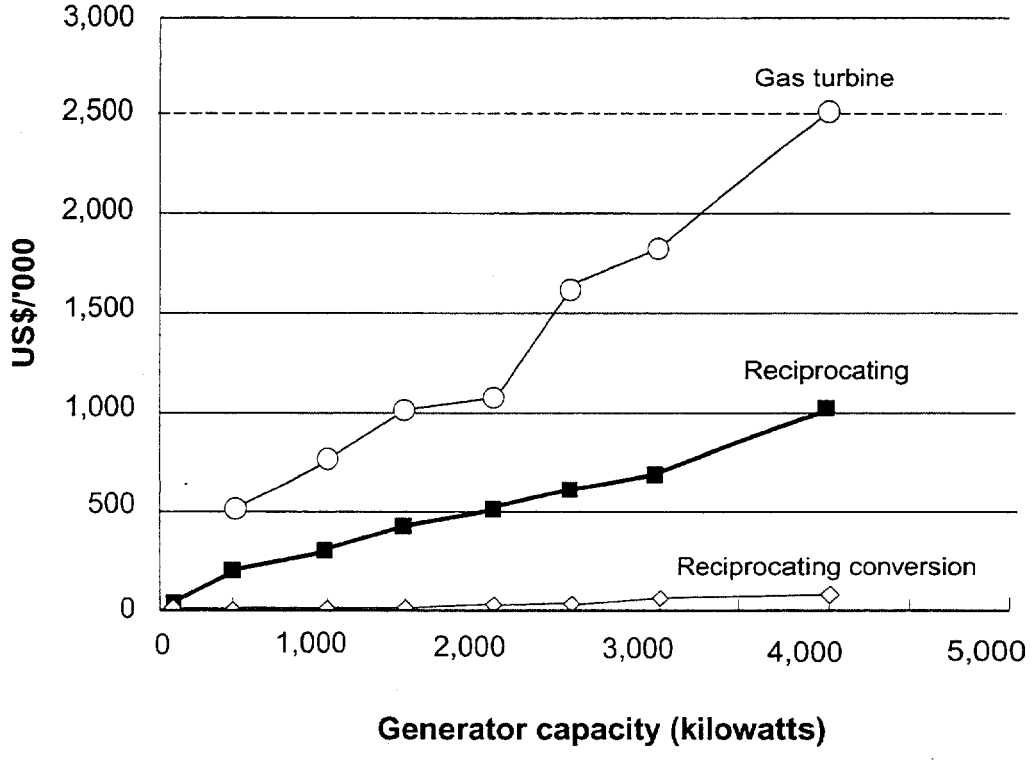


Consumption

6.4 Small industrial and commercial centers, hospitals, and airports may use enough gas to justify a project. The principal use of small-scale gas production, however, will be for generation of electricity. Such applications have often been neglected. Based, however, on deposits of gas of adequate scale or access to an existing pipeline and geographic proximity to a market, they could be efficient and environmentally beneficial ("small is beautiful"). That is particularly true if they are supplying gas as a substitute for biomass, or fossil fuels. In addition, small-scale use of gas could serve as a wedge for further gas market development and would have "demonstration effects" by the publicizing the advantages of gas.

6.5 In addition, using gas in power generation on a small scale seems now feasible (see Figure 6.2).

Figure 6.2 Typical Capital Costs for Electricity Production



6.6 Rules of thumb for assessing their suitability are as follows:

- *Economics*. Small-scale electricity production from natural gas will be economic when the ratio of the price of gas to electricity is less than 0.2 on an energy-equivalent basis and the load factor is higher than 0.6.
- *Converting diesel systems*. Converting diesel generators to gas is likely to be viable when the gas price, on an energy-equivalent basis, is 70 to 80 percent of the diesel price.
- *Using off-the-shelf components*. Generating power on a small scale from natural gas is well understood; many reputable suppliers can provide installations suitable for developing countries.

6.7 As noted earlier, the economics of distributing gas to households that typically use it only for cooking and perhaps hot water are clearly negative when traditional metering schemes are used. It appears possible, however, to develop more affordable, if perhaps less precise, metering devices preferable with prepaid cards. Another approach would be to install collective meters—for example, for an entire village—and then have the community handle cost allocation and monitor consumption.

Transport

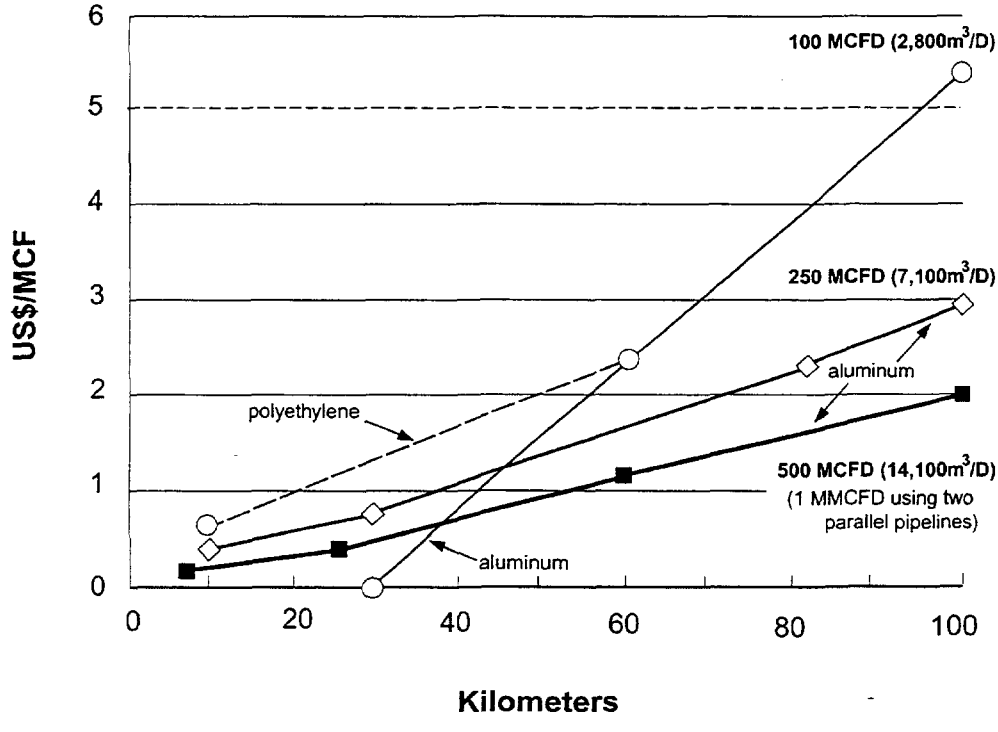
6.8 Pipelines with high transportation capacities require high pressures and large diameters, and both of these characteristics are achieved by using of steel as the material for the pipes. Such pipes are relatively high in cost, which increases roughly in proportion to the pipes' diameter. The laying of steel pipelines is expensive, too, as steel pipes are heavy and therefore costly to handle, and the

individual pipes must be welded in situ. In contrast, plastic pipe can be unwound from large spools easily and in substantial lengths—up to 1,900 m—and their basic material is much less expensive. Finally, joining techniques for plastic pipe are reliable and do not require expensive operator training. These advantages suggest that installation of plastic or aluminum pipelines can be undertaken easily in developing countries, without foreign assistance. On the other hand, plastic is limited in comparison with steel with regard to the diameters in which pipes can be made and the pressures they can handle. In fact, plastic pipelines have a much lower carrying capacity than steel pipelines because of the limited pressure even for pipes of the same diameter. However, this is often compensated by the much lower costs.

6.9 The same strengths and weaknesses in comparison with steel are basically true for aluminum pipelines as well as plastic. That is, the distinctive features of plastic and aluminum pipelines materials—notably their low cost and limited capacity—suggest that in combination with inexpensive gas production, both materials can serve as a way of commercializing small finds or hooking up additional small demand to existing high-pressure pipelines. Pipelines that can serve smaller volumes of consumption at still relatively low specific costs might help bring the advantages of gas as a clean commercial fuel to less densely populated areas—particularly suburbs or smaller towns that are not too far from larger gas-consumption points.

6.10 Figure 6.3 shows the pipeline transportation costs as a function of distance using plastic or aluminum pipelines. The capacity of the pipelines is between 1 million m^3/year and 5 million m^3/year—large enough to serve commercial centers, small industries, or both. For a distance of 20 km, costs of transportation by such pipelines are below $/1MMBtu, and for 50 km, costs are below $2/MMBtu. Built as an adjunct to an existing gas scheme, such a small-volume plan might be attractive.

Figure 6.3: Pipeline Transportation Cost, 50 Percent Load



Note: 10-year project life, 10 percent discount factor.

6.11 Plastic pipelines have been used successfully in areas in Europe with wet soils, where their safety record is as good as that of steel pipelines. It appears that with pressure intensifying to look for increasingly cost-efficient solutions in the gas sector, plastic pipelines may well get more attention even in traditional gas regions.

7

Commercializing Gas Projects

7.1 It is worthwhile to study the historical record of global experience in gas projects and recent developments in the gas sector. These suggest that a successful gas development in a developing country will have prerequisites such as the following:

- Attracting sound and strong commercial actors
- Instituting appropriate pricing and taxation
- Creating an adequate institutional and regulatory framework.

7.2 The challenge for any sort of gas development and marketing will always be how to set up commercially sound gas chains all the way from the production point to the end consumer.

7.3 Before addressing these issues, countries must define a realistic gas policy that is backed by a consensus of major parts of society. This requires a sober analysis of the situation to avoid wasteful decisions based on excessively high hopes.

Elements of Commercialization

7.4 In seeking to commercialize an economically viable gas project, a country must optimize the benefit of the project for the country while providing sufficiently strong incentives for the project to attract private investment. In contrast to oil, gas is typically marketed domestically, which usually implies that a market for the gas must be developed. That requires establishing an appropriate regulatory system for the downstream sector to protect the consumer interest. Even more important in the start-up of a gas project, the country must define a reliable framework for the investors. They should not be confronted later with unexpected requirements that result from ad hoc or opportunistic domestic political considerations that may change the original risk and reward pattern unilaterally to the detriment of the investor. To give the investors a clear indication of the framework of the domestic gas market, a regulatory regime needs to be designed in advance in reasonable detail.

7.5 A clear policy on gas with a reliable framework and corresponding competent institutions makes it possible for investors to assess risk in any part of the gas chain. The policy and the regulatory framework should be appropriate for the developmental stage of the natural gas industry. Thus, in countries such as those in SSA, the regulatory framework need not be too elaborate in the early stages. It would certainly be counterproductive to replicate the regulatory models of mature gas industries such as those of the United States and United Kingdom, with their large gas markets and multitude of

suppliers. Instead, a developing country with a single producing gas field and perhaps two large consumers—say, a power plant and a chemical plant—can probably rely to a large extent on contracts to govern relations in the sector. This, of course, is provided that a reasonable contract law is in place or is substituted by some recourse to international conflict resolution mechanisms. Regulation as such can concentrate in the beginning on technical issues such as safety, environment, quality, and metering standards. However, the country should keep in mind the potential next step in regulation. That step would be to ensure (in granting the license for the developing the gas field or for building the pipeline) that smaller gas customers, such as breweries or hotels, also have fair access to the gas.

7.6 In effect, the principal challenge in the structuring and regulating a gas industry at the early stages is more in attracting investors than in restricting them. The state not only has to define the rules for the sector but must also define how many players, and which ones, can participate. After the state has established that the overall development of the industry is likely to be profitable, the state should define the rules for the sector. The state should do this in a way that facilitates access for as many participants as possible and that assures the participants that they can expect to profit or at least see the opportunity to profit as a sufficient incentive to participate.

7.7 The private entities likely to become involved in developing a gas sector in countries such as those in SSA will probably be oil companies, distribution and public service companies, and power companies/IPPs. These companies know or should know how to organize themselves and their business and how to handle risks and do the work best. The state thus should generally refrain from active involvement as an operator in the sector. Instead, the state should concentrate on its role in defining the policy, setting the framework, and defining the regulations and supervising them. The state can acquire the know-how necessary to supervise the industry without financial or operational involvement of its own in the industry by drawing on international expertise from similar cases and by establishing reporting and publication duties for the private companies. A clear distinction of the state as strictly a policymaker and supervisor is the best basis for efficiently organizing the sector; this helps the state retain the arm's-length relationship that is necessary for fair regulation. The state also may wish to restrict its own financing in the sector when enough private sector investors are involved who are prepared to risk their own money.

7.8 Nonetheless, the state might have reasons to involve itself at least partially in the building up of a gas industry. One reason may be that private entities do not feel knowledgeable enough or confident enough about the country. They may hesitate simply because they do not want to spend so much money in just one country. Similarly, the private entities might have projects elsewhere in which they have more confidence, or they might harbor expectations that are simply too high on the return side because of a perception of certain risks (such as marketing and currency conversion risks). The typical example for an involvement of the state would be a national electricity company, which in the last instance takes the marketing and currency conversion risk for the IPPs. In general, countries wishing to develop a gas industry should take a pragmatic approach: *Encourage as much private sector involvement (including the domestic private sector) as possible, and reduce the state involvement to the level that is absolutely necessary. And in case of any commercial involvement by the state, the commercial function and the policy functions should be strictly separate.*

Gas Sector Policy

7.9 Once it has been determined that a national gas industry (or the substantial enlargement of a national gas industry) appears profitable, the national authorities should try to discuss and define or

reconsider a national gas policy. That policy should aim at creating as much benefit for the country as possible while giving the private sector as much benefit as is needed to interest them in the project. The broader the consensus in the country on the gas policy the better, as this will give all potential entrants into the market more comfort—particularly that change in the constellations of internal political power will not substantially alter the institutional and regulatory features of the sector. Thus, gas sector policy should address, on a long-term basis, the evaluation of reserves, supply, markets, and possibly exports for natural gas. It should also specify the role gas is expected to play in national energy supply and the nation's environmental protection policy (e.g., measures to reduce pollution in power production, industry, households, and commercial establishments). The state should outline which legal instruments are brought to bear in particular cases: laws, ordinances and regulations, and licenses and contracts. And the state should indicate what institutions should be created and maintained, along with the selection mechanism that it will apply to chose among several applicants for particular opportunities.

7.10 For example, once such a framework is defined for an environmental policy that aims at favoring the use of gas, this framework should be translated into legal instruments defining technical limits or introducing economic mechanisms to implement that policy. These could be ordinances defining technical standards such as the acceptable emission or pollution levels from certain plants (e.g., that exhaust gases must not have more than X mg/m^3 of a specific substance such as SO_2, or the pollution in a specified area should not exceed a defined concentration). Such clear-cut technical limits would favor the use of gas. Because of its clean-burning properties, gas will have economic advantages—mostly because of the lower investment required to comply with the established emission standards. However, where clear technical limits cannot easily be defined, or when it is better to install an overall limit on emissions for economic reasons, legal instruments giving strict technical limits may be replaced or complemented by economic mechanisms. Examples of economic instruments are a trading mechanism for emission rights or a penalty mechanism such as an emission-based tax whereby the negative externalities (e.g., of particulate or SO_2 emissions) are internalized. Also, these economic mechanisms would result in an economic advantage for gas, which usually does not contain particulates or SO_2. The environmental policy should outline what areas are to be technically regulated and what are to be economically regulated, when or in what sequence, and according to what principal rules. It should define the role of the state, of private companies, and of consumers.

7.11 It is important to note that countries need not expect to create such policies from scratch. Rather, they should plan to obtain expert advice to create the suitable framework.

Advertising the Opportunities

7.12 Once a country has clearly defined its policy for gas and hydrocarbons, it should seek to make that policy known to all potentially interested market entrants. That can be done in many ways:

7.13 A promotional campaign can give the interested parties general information illustrating the potential opportunities in gas development (e.g., facts on the geology, production circumstances, and market potential) as well as an outline of the policies envisaged for the sector.

7.14 Promotion mechanisms can also include more specific communications:

- Publications to make the policy and its operational details known worldwide
- Advertisements in specialized trade publications

- A home page on the Internet with relevant information, including a query function or contact information to ensure that questions can be answered expediently
- Public presentations
- More selective conferences and exhibitions
- Approaches to individual companies
- Invitations to interested companies to visit sites

7.15 It will be a good investment to involve professionals in such campaigns; this can be done through consultation or by actually delegating large parts of a campaign to professional organizations.

8

The Role of the State

8.1 The task of the state in a project involving private capital is to look after the interests of citizens and civil society as a whole while attracting enough capital for the project. It does this by creating the right incentives and guarantees to make the project work—that is, creating a stable framework for private capital and ascertain the protection of the interests of its citizens.

Looking After the Interest of Citizens

8.2 The state's effort to look after the interest of citizens should address four basic categories. The first involves issues of national control, including jurisdiction over the industry, control of decisions at important points, assessment of the impact of developing a gas industry on the country, and resource management. The second relates to protection of the environment and basic safety of the citizenry. The third involves ensuring the political voice of the citizenry in important decisions that affect their well being. The fourth is promoting the economic participation of citizens and national companies in terms of creating income for the state, of employment and other benefits created by a gas project such as ability to take advantage of clean fuels. These are addressed in turn below.

National Control

8.3 Ownership of resources is a crucial national issue not only for gas or oil but also for all mineral resources. Usually the state defines itself as the owner of all subsoil resources (however, in the United States, the owner of the surface land owns of all resources found directly under the property).

8.4 In establishing the mineral rights of a country one must define it vis-à-vis other countries and within the country concerned to distinguish it from other land-related property rights. The following principles are in force concerning international delineation of mineral resources:

- *Onshore.* The rights to minerals usually belong to the country owning the overlying surface. An exception is the United States, where these rights belong to the landowners. Subsurface rights may be subject to border disputes, however.
- *Offshore.* If no recognized international border exists, countries will follow the Fourth Geneva Convention of April 29, 1958. This implies:
    - Delineation of the continental shelf to a depth of 200 m or beyond that limit, if exploitation of resources is possible.

- Use of the median line principle (the dividing line between the sectors of two countries is defined by the point having equal distance to the nearest onshore point of either county) unless another boundary is justified.

This Geneva Convention has been amended by the UN Convention on the Law of the Sea of October 12, 1982, as follows:

- Redefined continental shelf as a minimum of 200 nautical miles from base line, maximum 350 nautical miles, maximum 100 nautical miles from 2,500 m isobath.
- Exclusive economic zones are defined.
- Border disputes relating to ownership of resources are to be resolved by the International Court of Justice in The Hague.

8.5 A method to overcome border disputes, especially onshore, is the establishment of a JDA, a Joint Development Area. In this model, no borderline is drawn, but a joint development entity is installed, and rules are established regarding how to share costs and benefits from the hydrocarbons exploited from the JDA.

8.6 Within a country, ownership of mineral resources is usually vested in the state. Companies exploiting mineral resources thus do so based on legal instruments concluded with the state. Usually this is organized as a service to state —that is, the company exploiting the resources is not acquiring the property of the resources while there are still in the ground. The service includes the risk-taking with regard to the exploitation of the reserves, and the company providing such a service is often paid in kind.

Resource Management

8.7 As the owner of national resources, the state is responsible for optimizing their use and for determining the extent to which they should be exploited or left for future generations. This implies also that the government aims at making the best use of the existing / proven resources with regard to mapping them and developing them efficiently. As a practical measure, the state should maintain a resource inventory system as a basis for licensing, development planning, production planning, and forecasting. This will usually involve creating a resource data management system for reporting to government / administration. As an additional benefit, these data should be made available to interested investors as well.

8.8 Part of the state's role is in managing the allocation of development rights to the private sector. Many examples and much literature speak to the question of how to organize licensing rounds for hydrocarbons. Most of the expertise concentrates on oil resources, however. Often gas is subsumed under the discussion of oil, and the specific challenges in dealing with gas are not addressed. This may have only minor implications for areas where a large and established gas market—such as Europe or North America—can be reached economically by the gas. But it may be a major factor in other areas and should be explicitly addressed.

8.9 For pure, nonassociated gas fields the question is this: Can a market for the gas be found that is large enough to support the development and the transport of the gas at the given distance to that market? Or, alternatively, are the volumes large enough to support the export of the value of the gas? If

neither of these questions can be answered affirmatively, then unfortunately development will have to wait until a suitable market has developed or until new technologies to export the value of the gas have developed, such as the gas-to-liquid technology.

8.10 If gas is found associated with oil or liquids, another intriguing question arises: What should be done with the associated gas when the oil / liquids are developed?

8.11 The strongest case for developing associated gas is that such gas is essentially supplied at zero or even negative cost when the state imposes a penalty on gas flared. (Flaring is less detrimental than venting of the gas because of the much higher greenhouse effect of methane compared with CO_2.) Some might even argue that given the potential to use gas later in the development of a country, a hydrocarbon find including associated gas should not be developed until a solution for the associated gas has been found. Such a postponement of oil revenues might even be economic for the country, depending on expectations on the development of the oil price. However, private oil companies involved in exploration will usually seek swift development of an oil find in order to get a rapid return on their expenses. Countries that impose requirements not to develop or to delay development of oil found with associated gas, if the gas would have to be flared, will be less attractive to international oil companies. In addition, traditionally cash-poor developing countries are likely to be under considerable pressure themselves to earn revenue from an oil field discovery, even if the associated gas has to be flared. In any case, maximum use of associated gas should be made before any flaring, such as using the gas for field operations (e.g., gas lift, power generation) and stripping the natural gas liquids off the gas, and the marketing of gas should meet as few contractual barriers as possible (e.g., allowing every partner to market the gas separately).

8.12 Another question stems from the claim by the state on natural resources. Often enough, this idea leads to giving the ownership of the gas ex wellhead to the state—and thereby also conveying the problem to the state of how to market the gas. In a case in which development of the gas is economic (i.e., a large-enough market exists), this may not be much of a problem. Developing the gas would replace oil products that would have to be imported or that can additionally be exported. Investing in the gas project will ultimately even improve the balance of payment situation of the state concerned, because the state's share of oil from a production-sharing agreement may serve as collateral for the currency transfer guarantee stemming from a gas scheme. The state can provide the price and currency guarantees the private investor may wish to obtain, or even finance the project. However, this case is rather the exception and in most cases the challenge remains to find an economic use for the gas.

Jurisdiction

8.13 Jurisdiction has also to be established and defined for offshore pipelines and in cross-border pipeline deals. In addition, the legal instruments with regard to installations on the territory of the state have to be defined, and the respective institutions have to be created. Again, many examples of oil and gas legislation dealing with all aspects of the oil and gas industry exist, as well as expertise about how to introduce them, so that countries with an emerging gas industry can find examples to be adopted to their specific situation.

Other National Control Issues

8.14 Given the importance that hydrocarbon projects have for a national economy, especially in developing countries, the macroeconomic impacts as well as the social impacts of such projects should be investigated. That will require the state to consider how to deal with the additional revenue without

creating distortions such as inflation. The state will likely also be dealing with the impacts of what might be a large foreign work force that may bring with it different cultural values, problems of language, and so on.

Environment and Safety

8.15 Detailed, internationally tested standards exist for protection of the environment and for safety of human life and equipment. Such standards are elaborated for the production aspects of hydrocarbon projects as well as for gas transport, storage, distribution, and consumption. There is no need to invent new standards; the existing ones should be selected and used for pragmatic considerations to the largest extent possible.

8.16 Models are available and tested on allocating control and responsibility for the environment between the industry and the state authorities. That is, the targets should be given by the country, along with the control mechanisms to supervise implementation. However, the means and instruments to achieve the targets should be left to the industry. It may be better to focus on the industry's internal control duties so that the industry is responsible for its own activities. The industry would thereby be required to take systematic action within its own organization so that the industry itself can ascertain compliance with the acts and regulations. The compliance should be audited by an internal organization, whose freedom is not restricted. The industry may be required to perform a risk analysis and take responsibility for compliance with its own safety and environmental goals. The state authorities concentrate on system audits and verifications and on coordination with other authorities involved.

8.17 With regard to technical rules and standards, it is best for countries to adopt an existing standard: ISO, API. The state may consider standards from a country with which it has a traditional relationship (e.g., from earlier decisions or from a colonial past) or from the companies that are investing.

Participation of the Population in Decisionmaking

8.18 Some issues of the participation of the population affected can be covered by legislation on the protection of the environment and by legislation and rules on safety standards. That should include the participation of the people affected in the implementation of a project and in the application of such legislation.

8.19 An important point is the question of how to deal with indigenous peoples who may have little or no contact with society beyond their own area of living. These people are most vulnerable to diseases imported by the activities introduced by a large hydrocarbon project that impinges on their territory. Their cultural heritage and traditional way of living may be similarly threatened. At the same time, their isolation makes these populations poorly equipped to assert their interests and autonomy, and they will need adequate support from government and other sources to exert and express their interests in such cases. Even if these issues are not specific for gas projects, they must be taken care of, whether in the more generic legislation on hydrocarbons or specifically for gas whenever this is more suitable. Provisions for protection of indigenous peoples should also be understood as supporting the reputation and stability of the project and thus as in the interest of the international investors as well as the country in question.

Economic Participation

8.20 The overall economic benefit of a project can be estimated in advance, as indicated in chapter 2. Beyond this, however, the state must decide how much of the benefit will go to the nation and how much will represent incentive and remuneration for private foreign capital. Although a profitable scenario is of course an important basis for attracting foreign investment, it may be equally important to create a realistic expectation of the benefits for the population. This can help "sell" the population on the project as well, but it may also be helpful to have a clear notion of the state's potential gain in order to prevent spending by the state that is not covered by revenue. This may be a particular issue for gas, where a common public misconception is that as much revenue can result from gas as from oil, which neglects the much higher transportation, distribution, and marketing costs of gas compared with oil.

8.21 The country will gain revenues from taxes and levies on the gas but it can also benefit broadly from the involvement of domestic enterprises and individuals in the project. Such involvement could include domestic banks financing parts of the project. It could also include local entrepreneurs developing small gas distribution and employment generated by construction. The gas might also come into use in smaller industry (because of its handling advantages, even if it might on a per energy basis not be cheaper than substitutes). Yet another benefit comes from training of a work force in skills relating to gas applications. Clearly, a good gas policy can define a framework that maximizes the positive effects for the country beyond the pure revenue.

8.22 Finally, an important positive effect of the introduction of natural gas is the reduction of pollution from burning of biomass, coal, and other fuels. The gas policy should maximize the benefits of pollution reduction by suitable legislation.

Creating an Attractive Framework for Private Participation

8.23 In view of the positive revenue contribution and because of the positive impact on pollution, the state / country should see if it can get gas projects going, having due regard to the protection of the citizens. The investors and operators will be most concerned to have a stable framework and environment, especially predictable rules on taxation and other government revenue. In the end, a participant should be free to realize a profit and to repatriate capital, which implies that the investor can always transfer revenues into hard currency.

8.24 In defining and setting up the sector structure and administering it, and possibly even participating, the state should distinguish clearly between its different functions. That is, the state must clearly separate its operational from its administrative responsibilities not only to prevent conflicts of interest but also to avoid bureaucratic delays in regulatory decisions and assessment of investment proposals.

8.25 Note that special considerations may apply for the development of small gas schemes in the sense that these may be left largely or entirely to local entrepreneurs. The lack of involvement of foreign capital eliminates foreign exchange issues. To some extent for small gas schemes the role of the state is much more clearly defined as the supervisor of the system, although small gas projects also need good governance to keep their operation in line with reasonable technical and economic standards.

Prices

8.26 In some cases, the state has not only determined the prices for the gas but has also allocated volumes to different consumers. Although the motivation for volume allocation seems understandable, it is extremely unwise and a vestige of poor central planning. One of the primary benefits of introducing gas is in providing choice to consumers. If consumers are not attracted to gas by its price and quality, it is of no use to force them to use it. If the demand is higher than the volumes available (which would be the exception in Africa), then the choice should be left to those who are able to offer the best price or otherwise the best conditions.

8.27 Also gas prices are best left to agreement between the market participants. In view of the natural monopoly character that gas transportation very often has and gas distribution practically always has, some form of regulation of the transportation and distribution tariffs will be adequate. The same applies for the tariffs to small end-consumers, who need protection against abuse of dominant market positions. Such economic regulation is best provided by an independent regulatory agency that can assure all market participants of fair treatment.

8.28 Subsidies for the poor are better given directly and only to them. Such subsidies are typically provided for gas in temperate-zone countries so that no one freezes in winter. In tropical developing countries, consumer subsidies are better applied to purchase of appliances to use gas, as the up-front costs can be a deterrent to choice of gas. Subsidies can be provided explicitly via the distribution company billing system, particularly if the concern is that direct cash subsidies will be misused. The same applies to subsidies to certain industries. A most common example is subsidizing agriculture by state-administered gas prices to the fertilizer industry. It is of course legitimate for a state to give incentives and subsidies to industries or to parts of the population. However, doing this via state-administered prices will always lead to economic distortions.

8.29 The market effects of gas prices depend heavily on the prices of the substitution fuels. If these are distorted, then gas prices will also be affected either by a distorted level or by a distorted relationship to the substitute fuels. In general it is not up to the state to set prices either for gas or for its substitutes.

Taxation

8.30 Energy taxes are widely used to raise income for the state. One argument is that taxation of energy gives an incentive for its efficient use. If the consumption of energy is to be taxed, then the taxation should ensure that gas is not disfavored by a higher tax compared with the competing fuels. Policymakers might consider the environmental effects of various fuels by applying different taxation levels in line with the fuels' environmental impacts (thereby internalizing externalities).

8.31 When it comes to taxes and levies on the companies, the best strategy is to tax the profit of companies, in line with their commercial success (e.g., by a tax on profit). A flat tax or royalty on the output or throughput may risk projects' commercial viability—especially that of marginal projects—and may thus prevent their realization. A taxation system for an emerging gas industry should be designed to give incentives to reinvest into the country. This implies that establishing a ring fence (i.e., a practice of not allowing the setting off of the losses of one project against the profit of another) around a given project should be avoided.

8.32 In any case tax and incentive schemes for gas should be carefully thought out. If poorly designed, they can prove a stumbling block for otherwise economic gas projects.

The Legal Instruments

8.33 As noted, the government should keep its different roles distinct to foster better decisions, higher efficiency, better coordination, higher transparency, reduced bureaucracy, and reduced uncertainty. The legal and regulatory system should form an incentive system to reduce differences in objectives between industry and society. Toward that end, it should draw on existing legal and regulatory experience from other countries. Central to this process is creating an adequate hierarchy of legal instruments.

8.34 The *law* is intrinsically relatively inflexible. If key sector issues are regulated in legal enactments, the negotiable elements can thereby be reduced, resulting in higher efficiency and guaranteeing nondiscrimination. The law may thus be considered appropriate to the following functions:

- Creating long-term stability in the basic framework for the sector
- Covering main terms, conditions, and requirements
- Authorizing the administration to issue regulations and creating the necessary regulatory institutions.

8.35 *Regulations* are appropriate for the following functions:

- Controlling depletion and, taxation
- Minimizing flaring of associated gas
- Ensuring compliance with internationally accepted standards for pipelines, safety, and environment
- Ensuring protection against dominant market positions.

8.36 There is little doubt of the necessity of technical regulation (to ensure the observance of safety, environment, and other technical standards) upstream and downstream in the gas and oil industry. There is also a widespread consensus on the issues and the range of methods of technical regulation. The debate on the necessity and the extent of regulation is more about economic regulation. The main issues here are access by third parties to infrastructure and exercise of control over tariffs and prices in areas not subject to sufficient competition. The term *regulation,* thus, unless otherwise indicated, is used in the sense of economic regulation. A question best addressed by regulation is how to minimize flaring of associated gas.

8.37 *Contractual agreements* take as their proper sphere the definition of the terms of production sharing, joint ventures, licenses, and service contracts. Countries may wish to use model agreements to standardize the terms. Most of these agreements (such as production sharing agreements) were originally developed to deal with exploration for and production of crude oil. Many of them would merely contain a clause to deal with the case in which gas (associated or nonassociated) is found, or a clause by which associated gas is made available free of charge to the national oil company. In order to develop the benefits of gas for a country, such agreements should contain a gas clause. The clause should deal with both associated gas and nonassociated gas. Although the rules to minimize gas flaring or impose a penalty on flaring are probably best dealt with by general regulation, production-sharing agreements should deal with the rules and incentives to make the marketing of found gas economic. The

main incentives would be to reduce the government take for gas compared with oil (e.g. by lower royalty rates, a lower share of profit gas, smaller shares of carried interest, or a higher depreciation rate on gas-specific investment). For crude oil, world market prices can serve as a benchmark for arm's-length transaction prices, which are needed as a basis for determining the government take. Unless gas is sold according to prices set by the state, gas prices agreed under contracts with arm's-length partners might serve as a benchmark for the purpose of defining the government take.

8.38 *Guidelines* are nonbinding but well suited to establish good practice in the industry. They do the following:

- Reference international standards, which is more cost-efficient than establishing notional standards.
- Govern the terms under which licenses, permits, consents, and approvals are issued.
- Indicate the strategies for safety and environmental protection. Hence, guidelines will focus on industries' internal control duties, based on system audits and verifications. The licensee will usually perform its own risk analysis and set own safety and environmental operational goals, complying with the environmental legislation in force.

8.39 The main guiding principles of the gas policy should be continuity and predictability. The economic result, the division of risks, should be stable over time, and necessary changes, such as changing technical, safety, and environmental standards, should follow rules set in advance. These changes might involve, for example, following the state of the art for technical, safety, and environmental standards.

Ensuring the Stability of the Gas Chain

8.40 The gas chain includes a series of crucial links to the final paying end consumer: production—transport—distribution—power generation—transport of power—distribution of power—final use of power. The main challenge is to ensure the stability of the chain from the production point to the end user. In this context, *stability* means not only technical stability from the wellhead to the final consumer but also the stability of the cash flow and the commercial conditions. That is, investors must have enough incentives to invest and to stay satisfied with their investment over the project's lifetime; at the same time, the commercial arrangements must keep the consumers happy, or they will not use or pay for the service. The following are two essential conditions for a stable gas chain:

- *Contract law, pacta sunt servanda.* This is necessary to enforce contracts and defining the consequences of nonfulfillment of contracts (e.g., to stop service after warning, as soon as a certain amount of arrears have accumulated). This is of special importance for gas downstream, given the long chains of transactions, which must not be interrupted, if the whole system is to work. Unlike oil, gas is traded in a domestic context, which means that the deals are subject to domestic law, which must address these issues.
- *Rules of conflict resolution.* These are crucial, especially between private companies and the government or state-owned enterprises. As gas is sold in the domestic market, most disputes may in a first instance become subject to national jurisdiction. Given the size of gas projects within the economy of developing countries, the resolution of major conflicts requires an independent body with reasonable experience in handling such large

disputes. Investors will tend to request that disputes will finally be settled by international arbitration.

9

Structure and Regulation of the Gas Industry

9.1 In a fully competitive business, the state does not need to intervene. The market participants themselves are best positioned to set prices and standards through competition and selection. In some cases, even technical standards may be left to the discretion of the market participants. In industries such as the oil and gas industries, whose production and distribution instruments as well as products have potential large impacts on health, safety, and environment, the need for technical rules and their implementation seems obvious. Usually these rules are best set and implemented by the state, as the legitimized representative of the interests of its citizens. Also, when it comes to the economics of oil and gas projects, the state may need to set rules for the players. One of the important issues concerns who is allowed to participate in what part of the industry. In any case, the participant must be technically and commercially qualified to undertake its business.

9.2 However, considerations beyond qualification may come into play, and these may lead to restrictions on certain participants from engaging in certain parts of the gas chain. These restrictions may well independent of the company in question. For example, several parts of the gas chain may be restricted to a limited number of players, as when exclusivity is granted for the exploration and exploitation of a defined area. Such exclusive concessions may be granted to build pipelines or a gas grid, and exclusivity may even be granted to market gas in a defined area or sector. Also, rules may apply by which the same company may not participate in different parts of the chain simultaneously or by which shareholding in another part of the gas chain is restricted. The arrangements (apart from qualification) by which companies can participate in the different parts of the gas chain and by which they are permitted to deal with other participants in the gas chain in effect determine the structure of the gas industry.

9.3 Again, optimal results are achieved if the participants in a market can act freely, according to their own assessment of their commercial benefit. The exception to the rule is an abuse of a dominant market position, which may be acquired de facto or linked to a natural monopoly. Such a case may require the intervention of a regulatory agency. Regulation may also be needed where the state is granting exclusive rights, which is necessarily the case for exploration and production rights from a defined area. This grant is a deliberate decision by the state with regard to concessions to use public land to build pipelines or gas grids or to enforce a right of way for a pipeline against a private landowner. These issues are dealt with under regulation that defines the conditions under which exceptions are made to the rule of free commercial activity of the companies involved in the gas chain. (This chapter deals mainly with regulation; the structure of the industry is described in the next chapter.)

Regulation Upstream

9.4 Regulation is necessary in the upstream sector because gas projects are large, complex, and take place over long time spans. They may have significant social and economic impacts. Also important, they involve many governmental bodies as well as strong, highly capitalized international oil companies, which may have varying incentives that must be reconciled if projects are to succeed.

9.5 Continuous activity in exploration is most effective, countries should carefully consider developing a licensing system for gas exploration and development, including licensing rounds at regular intervals. The licensees should be encouraged to define their work commitment by themselves, within a given framework.

9.6 Several types of licenses may be issued, depending on the status of development. A *reconnaissance license* conveys nonexclusive rights for surveys. An *exploration license* gives a company an exclusive right for 6 to 10 years to carry out a specified work program to explore for hydrocarbons. A *production license* usually grants the rights of development, production, and removal for 30 to 50 years.

9.7 The issues to be covered by upstream regulations for oil will also have to be covered for gas. However, as gas cannot be marketed easily on a world market, gas may need some extra regulations dealing with disposing of or marketing the gas. These regulations may be similar to those for oil when the gas or its value can easily be marketed. For example, when the gas can be exported or when the value of the main volume of the gas is captured by goods that are exportable to a world market, the issues would be similar to those for oil, because volumes can always be sold (if the price is right), and the value of the gas is realized in international currency. Once the gas has to be marketed domestically, upstream regulation has to be complemented by the issues of allowing for the marketing of the gas and the issue of realizing the value of the gas in international currency.

9.8 Two models come to mind. In the first, the producer would develop the gas field and a gas infrastructure and in the end would be remunerated in international currency. The remuneration would be based on a tariff structure that would allow the producer to recover the costs incurred, where the tariff would be guaranteed in last instance by the state. Without taking any marketing risk or price risk related to prices of competitive energies or end products, the practitioner of this model would provide the country with the development of a gas infrastructure in exchange for covering the costs including a reasonable profit on equity. The arrangements may be very sophisticated in detail. The arrangement may be a contract chain, by which the gas is sold to power plants under a minimum-pay contract with a fixed gas price (in international currency). The power plants could be IPPs, which sell the power to a state electricity company under contracts that provide for minimum off-take guarantees for the electricity and thereby ensure cash flow. Together with a currency transfer guarantee by the state, this arrangement would mitigate the marketing and currency risk of the project for the gas producer. It would result in a guaranteed profit from the project, which, beyond technical and reservoir risks, depends on the political country risk but not on marketing risks.

9.9 In the second model, the structure of the gas industry allows for free marketing of the gas and ensures that the competing energies are priced in line with world market prices. Given a sufficiently large energy demand in the country and free currency transfer, the gas producer would have a similar risk pattern to that of the marketing of oil. The gas producer would have a marketing risk against a large enough demand, which the producer can cover by competitive pricing. The producer also has to deal with oil price movements, which are translated via the exchange rate into prices in national currency. As long

as the national currency is freely convertible and transferable, the producer can transfer back the earnings from selling the gas in competition with oil priced at world market prices.

9.10 Model 1 might be dealt with mainly in terms of upstream regulation, possibly leaving the gas downstream business to a command and control approach. The second model needs clear downstream structure and regulation.

Regulation Downstream

9.11 There are no principal differences between oil and gas with regard to technical regulation. Also upstream, the needs and principles for economic regulation are much the same for oil as for gas. The main difference is downstream, where crude oil and oil products can by their nature be traded on a market while gas is bound to a fixed infrastructure, with large economies of scale. Furthermore unlike for oil, for gas the transportation and distribution costs are a substantial part of the value of the gas, making the access to the economies of scale for transportation and distribution a decisive point to get access to the market. Therefor regulation of the downstream part is an important issue for gas for which no rules from the oil exist to draw from.

9.12 The following sections discuss the nature of natural monopolies and the resulting needs for economic regulation, which has to address the questions what to regulate, how to deal with access and tariffs and the main methods and examples. The question of pro active vs. a supervising regulatory agency is then discussed and finally the issue what size of regulation is adequate to the development stage of an emergent gas industry is raised.

Economic Regulation

9.13 Although technical standards and regulation apply to most industries, economic regulation applies only to industries that are either a natural monopoly or a monopoly based on exclusive rights or concessions given by the state. Why or when is economic regulation necessary in the downstream part of the gas industry? As suggested, the economics of gas transportation and gas distribution grids make them near-natural monopolies or outright natural monopolies respectively. The decisive criterion for a natural monopoly is *subadditivity*, meaning that for any demand size in a given market, the costs to serve that demand size are less than the sum of the costs to serve two parts of demand that add up to the same size of demand. This means that the economies of scale of one production device stretch over the whole range of possible demand in a given market. Under this condition, a newcomer can hardly economically attack an existing provider of a service, as the incumbent provider can always extend production at additional costs that are lower than the costs of a newcomer. The danger of a natural monopoly is like that for all monopolies in that monopolistic pricing tends to suboptimal allocation of resources and to hinder development.

9.14 In some cases, transport pipelines do not fulfill the criterion of subadditivity. For example, the issue may be irrelevant because the producing fields or the markets may be located in different areas. Similarly, the question might be irrelevant, if the pipeline travels such a short distance that economies of scale are not that important. The criterion would not be fulfilled in large gas markets where transportation capacity of an optimal size is small compared with the market size. For distribution grids, in contrast, the criterion of subadditivity will usually hold, because in a given area an existing grid can always be expanded to serve new customers at a cost lower than that of constructing a new infrastructure. That conclusion is similar to that of electricity distribution. Still, in comparing the

economies of gas grids with electricity grids, it must also be considered that—contrary to the case for electricity—gas has easily available substitutes for its applications that give a market-defined upper limit to the price at which gas can be sold

9.15 Moreover the state or a municipality can in effect constitute a national transportation or a distribution company even as a legal (absolute) monopoly if it gives it an exclusive concession to operate pipelines in the country or a grid in a specified area. However, the possibility of physical substitution is always given for gas unless even that is excluded by the state enforcing the use of gas in certain areas or applications.

9.16 Regulation can mitigate the potential dangers of monopolies by, for example, ensuring that the front runner in the market is always contestable. This can be achieved either by affordable substitute products or by other companies building pipelines—that is, no economic restrictions on the building of additional pipelines, grid extensions, or a line from one customer to the next. In the case of outright natural monopolies (or monopolies defined by an exclusive concession given by the state), more explicit rules are required to ensure a "competitive" outcome. More explicit rules are also required where the possibilities of contesting the incumbent company are limited for other reasons. These rules will involve dealing with market structure, pricing, and consumer protection or more concrete the question of access and tariffication for the gas pipelines and the gas grid and possibly the pricing too the end consumer. The supervision of the rules and their enforcement will require establishing a regulator or an antitrust authority

Obligation to Allow for Access

9.17 The obligation to allow for third-party access could be an obligation on the owner of the *system to negotiate* a fair deal for access to the system by the third party. The process would be subject to supervision by a regulator or an antitrust authority to ensure that the third party is not discriminated against other parties with regard to access to the system or to the tariff it has to pay. Perhaps a more difficult question, is what constitutes discrimination against the *owner* of the system? This is because the owner of the system, as the one who has taken the initial risks to invest into the system, is obviously in a different situation than the companies looking to use the system, which did not and do not have to bear similar development risks. The owner thus can rightly claim different treatment. The commercial result would in case of a negotiated access primarily remain under the control of the pipeline owner or at least the parties involved.

9.18 Mandatory third-party access would mean that access has to be granted by the owner under rules defined by a state body. That agency first has to define standard conditions for access and use of the system and in addition a standard tariff or a standardized procedure (such as public bidding or auction) to determine the tariffs. In this case, the system owner no longer has influence on the economic result. The owner will therefore want to know the rules of the regulation before making an investment decision and will be very anxious that the regulations stipulated in the beginning are not changed later on.

9.19 The following text deals with aspects stemming from a regime of mandatory third-party access. Some of the considerations may also be used to judge whether a negotiated third-party access is a misuse of monopoly power.

Access Rules to Pipelines

9.20 Third-party access is often clearly in the interest of the country to optimize resource management. The typical case on the production side is that of smaller satellite fields to a larger field for which the basic transport infrastructure is initially built. Third-party access to a pipeline might be helpful in phasing the production profiles of the satellite fields into the production profile of the main field, which allows for making best use of the transport infrastructure and for developing at all the satellite fields, which may be too small to pay for a pipeline of their own.

9.21 Overdimensioning of the diameter of a pipeline by 2" or 4" may be in the interest of the country, as it increases the transport capacity of the pipeline overproportionately, whereas costs are roughly proportionate to diameter. This may give room for supplying additional medium-sized customers, such as commercial centers or industrial parks. These customers would be not supplied from the main high-pressure grid but rather from a gas grid with lower pressure.

9.22 The demand by industrial parks; commercial centers; or administrative centers, such as airports or harbors, may well be a crystallization point for the development of a local gas distribution grid—perhaps even to the extent of supplying households with gas.

9.23 It must be decided if and to what extent and at what stage of an emerging gas industry access rules are necessary. It also must be decided which tariffs and rules to determine tariffs are adequate to in view of the risk pattern involved for the investors and the benefits for the country, including the protection of the customers.

9.24 Below, some of the issues to be decided in establishing mandatory third-party access are listed and briefly highlighted. It should be kept in mind, however, that in the developing stage of a gas industry it is more important to find pragmatic solutions to the questions that lead to a dynamic development of a gas industry then to have optimal models for all those questions. As gas industries vary largely from case to case, models of other countries can hardly be considered a precise blueprint. Rather, they should be screened for elements useful for the own country.

What Part of the System Should Be Subject to Third-Party Access?

9.25 It is commonly held that only the parts of the system that constitute a natural or national monopoly should be subject to third-party access. This would usually include gas distribution and in most cases the gas transportation system. Compression is a tricky issue. Compression along the pipeline is certainly part of the transportation system and thereby part of third-party access. Compression at the front end of a pipeline, however, may not be seen as part of the transportation system, as any party could provide compression—perhaps even by using the initial pressure of a producing field. Devices for load management such as peak-shaving plants or storage vessels are not necessarily considered natural monopolies. That is, as a variety of instruments for load management exist that do not fulfill the criterion of a natural monopoly, no reason exists for introducing third-party access. Providing metering is clearly an activity not linked to a natural monopoly.

9.26 Thus, for the introduction of third-party access, it is important to define clearly the parts of the gas system that are subject to third-party access and those that are not. For the parts of the system that are subject to third-party access, the capacity of the system and the capacity available must be defined. The total capacity of a system seems to be a technical issue that can easily and unambiguously be defined. This is true, if the system is a pipeline from A to B, and the access is also from A to B. It becomes more complicated, however, if access is only sought for part of the distance between A and B,

because the access may block capacity upstream or downstream. It becomes even more complicated if the transportation system is not just linear, but interlinked with other pipelines, where all kind of pressure restrictions may apply that are difficult to assess. This is particularly true once the system has a gridlike character, like distribution systems (and many electricity systems), and the single instance of access or transit is relative small compared with the overall capacity handled by the grid.

9.27 It is also very important to define the conditions for access. The most important are the specifications the gas of the third party. The gas should be in compliance with the quality spec on the pipeline, and it should comply with the pressure required by the pipeline at the inlet point.

9.28 Usually a part of the capacity of the system would be booked, being defined as a certain absolute transportation capacity or as a share in the capacity of the system. The question of curtailment in case of capacity constraints should be defined.

Timing for Third-Party Access

9.29 It makes a large difference whether access to a pipeline for third parties is confined to the planning stage of the pipeline or not. The case of third-party access during the planning stage (usually called *open-season pipeline*) is relatively straightforward. All interested parties may book firm capacity on the pipeline to be built, so that all partners profit from the economies of scale and share the risks of the project. The allocation procedures of costs and risks are defined by the free will of all parties involved or are at least equally shared in case of intervention by the state. An open-access regime that allows access once the pipeline is laid (i.e., all risks have been taken) will always raise difficult questions: What capacity is to be made available for newcomers? If accidentally or on purpose the pipeline company has overdimensioned the pipeline so that the pipeline company took a risk, shouldn't the pipeline then have the right to make use of this capacity at its own discretion? If others should have access to the pipeline after it is built, what tariff is appropriate to compensate the builder for the preinvestment and the risk taken? Adding capacity later on may pose even more difficult questions, when the access of newcomers results in an investment obligation of the incumbent company to increase the capacity of the pipeline (e.g., by adding compression or by partially looping the pipeline). It also might result in a need to define rules to determine whose transport capacity is affected and in what way reduced availability of the

9.30 Usually third-party access would refer to cases where an interested party would get access to an already existing gas pipeline or grid. The question would then be for which duration the applicant has to book capacity, what are the announcement periods, and what is the commitment on both sides. These questions are closely interrelated with the access rules and with the setting of tariffs. Booking capacity would usually be at least for a year or several years, especially in developing gas industries. Getting access to a gas transportation or distribution system for shorter periods as a rule is rather typical for very mature gas industries.

Rules in Case of Inadequate Free Capacity

9.31 The sum of transportation capacity requested by third parties may exceed the free capacity, which would raise the question of allocation. One approach would be that tariffs are given, so that there is no preference on commercial grounds. Access then could be on a first-come, first-served basis or companies wanting access for a longer time span get priority over companies wanting access for a shorter time. A sharing of the free capacity according to some objective criterion might also be an

approach. This would be linked to the requested capacity, which opens the door for some tactical behavior.

9.32 A special question is how the request for capacity by the pipeline owner should be treated. Another difficulty is how to treat contractual delivery obligations, which need corresponding transport and are not defined by a certain capacity but by the obligation to supply all emerging demand (e.g., depending on temperature or market development).

9.33 When tariffs are not defined, then bidding for free capacity or using a similar mechanism such as an auction is possible. Both do not raise questions of allocation and may also be applied independent of shortage of spare capacity. The incumbent pipeline does not know what earnings it forgoes if it wants to hinder a third party by participating itself in the bidding, which limits its room for tactical behavior. In both cases it is very important that the procedure is public, to guarantee fair chances to the participants.

Tariffication for Infrastructure

9.34 For generally applicable tariffication, which might be offered by a system owner (to be checked for fairness by a supervising authority) or imposed by a regulator, the following main questions have to be answered:

- *How are costs and risks defined?* Gas infrastructures are characterized by high fixed costs depending on investment and relatively low annual operating costs (to maintain the operability of the system, which is usually also a percentage of the investment) as well as low costs that depend on throughput. The main parameters influencing the level of the tariff therefore are the investment basis, the depreciation time, and the assumptions on interest rates and financing. On the risk side, once the investment is made, the main costs are fixed, and there is practically no room to reduce costs to adopt to new situations (e.g., a lower-than-expected throughput). Increasing capacity to a growing throughput is possible within limits by adding compression. So the pipeline owner inevitably has to take a long-term commercial risk with regard to the development of throughput that may be jeopardized by reduced availability of the gas supply source as well as by a market development for the gas that does not meet expectations.

  A well-maintained gas pipeline can well be run for 30 years and more. However, the depreciation time (also with regard to profit taxation) is usually about 20 years and most pipelines are amortized after that period. This difference between assumed economic lifetime and technical lifetime could be justified to cover some of the commercial risk of the pipeline described above. Under that interpretation, the accelerated depreciation would be a part of a risk compensation, which can be realized by the pipeline owner once the system is written off and amortized but still fully functional. Should a third party profit from such a situation, for which it has not contributed? Another way to compensate the owner of the pipeline for the risks taken would be to add a risk premium on the interest rates of the financing instead of an amortization time that is shorter than the technical lifetime of the pipeline.

  Also with regard to the investment basis, should a third party be affected by price moves for the construction for a pipeline system? If the prices for new pipelines rise, why should the third party profit from the lucky decision of the incumbent pipeline, which the

third party did not share? On the other hand, why should the third party suffer from high cost for a pipeline that stems from the owner's having chosen an unfavorable moment to construct the pipeline or lack of cost efficiency? One approach is not to look at the book values of the pipeline or the grid but instead to base the tariff calculation on the actual replacement costs and prorate them in line with the capacity booked. This would place the acceding party into the situation as if it were building a pipeline itself, in line with the actual costs of the pipeline building market, but would allow the third party to realize the economies of scale of the pipeline that is already built.

- *How is the utilization risk dealt with?* One approach for dealing with utilization risk is to split the costs for an infrastructure between those using it (or booking capacity on it) during a certain time period (cost of service). The result of such a mechanism would be that the owner of the infrastructure would always cover the costs of the infrastructure whether or not is it is fully used and that the price for a service offered from an underutilized facility would go up instead of going down, as everybody would expect. This may end up in a "death spiral," where lower usage of the pipeline results in higher tariffs, which in turn result in lower usage, and so on. This scheme gives hardly any incentive for efficient use of the infrastructure.

One way to introduce more risk taking for the owner of the infrastructure would be to set ceilings in advance for what the owner of an infrastructure may charge. This value might be arrived at based on the replacement cost principle or on basis of book values with some mark up to compensate for the risk of under utilization and based on a usage below 100 percent. The values could be up for regular review (at intervals of between 3 to 5 years) which would not lead to retroactive corrections, but apply to the time after the review only. Having fixed tariffs or ceilings for a number of years gives incentives for cost saving and more efficient use of the pipeline. A review at regular intervals makes sure that the gains in efficiency are shared.

A ceiling gives more commercial freedom to the owner of the system compared with a straight tariff. However, it offers more risks of discrimination. In situations with only one infrastructure, the objective of preventing any discrimination between third-party users might prevail.

Discrimination supposes that starting conditions are equal. It might be argued that there is always a difference between the owner of the system, as he bears the marketing risk for all the lifetime of the project and any third party user, who comes in later.

By the same argument, it seems to be fair to provide for different tariffs dependent on the duration of booking capacity on the system.

- *How should costs be allocated?* There are still many examples in which the tariff for transportation is charged by volume instead of by capacity. This would favor gas at lower load factors over gas with higher load factors because they require less capacity per volume. In cases where all gas is transported at a similar load factor, such a system might have the advantage of simplicity and that every shipper could automatically—according to given priority rules—use free capacity left by the other shippers.

Systems where the shippers have to book a certain capacity and have to pay for it, regardless of utilization seem to better reflect the costs caused by the shipper in the system. It seems also to be easier to trade on rights to transportation capacity.

Another question is, whether a tariff should be tailor-made to a specific section of the infrastructure used or whether a tariff should be calculated based on generally applicable yardsticks, which are independent of the individual section used. Specifics to be reflected in a tariff of the transportation section to be used could be pressure drop, diameter, pipelaying conditions on that specific part of the system, implications and restrictions caused by the use by a third party upstream and downstream of the part in question. Such an approach—although justifiable—seems not very practical, as it would probably lead to very long discussions and high insecurity about the costs to be expected for a specific project and force any third party wanting access to the system to lay open most critical details of their project.

More universally applicable approaches would relate to capacity used, and distance or location assuming standard pipeline diameter and standard costs or starting from the overall costs of the system. Such an approach gives third parties that want to use the system a good estimate of the costs to be expected without having to reveal their case to the incumbent system owner.

9.35 An issue concerning the shape of the tariff is to the extent to which distance and location are reflected in the tariff structure. The two simple extremes are a *distance-dependent tariff,* which is defined per capacity per distance (e.g., as $/m3/h/km/year) or a tariff that is completely independent of the distance used by the third party, often called a *stamp tariff.* Justification for the first system stemming from the cost side, might be in cases where the flow of the gas can be allocated to a third-party transport request, so that the opportunity costs for the use of the system are distance related. This will mostly be the case for the transport of gas in the beginning of a gas industry, when the transport system is not yet interlinked. With a high degree of interlinkage, average transport distances are reduced. Similarly, with distribution grids that are highly interlinked, the change in gas flow caused by additional use of the system will not coincide with the linkage between the additional input and output. In these cases, a stamp tariff seems to be appropriate.

9.36 There are a lot of systems in between these extremes. Included are zone tariffs, where the area is divided into several zones, and each zone used triggers an extra stamp. Another interesting, although rather sophisticated, tariff system is one of inlet and outlet tariffs, which reflect the supply and demand situation in the various regions of a country, a system that can also value bottlenecks.

9.37 There is no straightforward choice for tariffication, and it will be fruitless to look for any method that "automatically" produces fair results. It is more important to look at the dynamic triggered by a given system and to judge whether that dynamic is in the interest of the project or the country or the parties involved.

Gas Prices to the End Consumer

9.38 As far as smaller gas consumers are concerned, their main interest may be first to get access to the gas at a fair price. Regulation for these customers would deal with two key questions: (1) Who has a right to be supplied with gas and who has the corresponding obligation? and (2) What are the prices or the price limits for customers that do not have enough negotiation power of their own?

9.39 Point 1 touches on the question of public service, which may be disputed for gas, to the extent it can be substituted. As mentioned, it makes sense for a country to make sure the use of gas as a domestic and clean source of energy is not blocked for reasons of convenience of large players, who may concentrate on large schemes due to their low transaction costs.

9.40 Point 2 involves the fact that emerging gas industries may start with monopolistic price discrimination, at least in the beginning, as this may be necessary to make a project viable. Consumers would pay according to their willingness to pay (which is objectively limited by the substitution possibilities), and all consumers who are willing to pay at least the marginal costs of supply are served. It is an approach that would still lead to an economic optimum. The entire consumer rent goes to the producers, which may be necessary at least in the beginning to get a project going. When this leads to profits beyond a normal rate of return, this could be shared by (progressive) profit taxation by the state. Given a tax system with the right incentives such profit could be put toward to developing other projects in the interest of the country. Also, it may be legitimate that in the early development stage the consumer rent goes to the state before it goes to select consumers. Later, when the gas industry and the country are more developed, the price may be determined by gas-to-gas competition, where part of the consumer rent goes to the consumer or by setting consumer tariffs based on the cost of production plus the allocated costs of the infrastructure. Again it seems to be more a question of the dynamics aimed at, than a question of fairness.

Proactive System (Regulator) vs. Supervising System (Antitrust Authority)

9.41 In the more mature gas industries in free market societies, two directions toward regulation can be observed: one in which the regulator takes a more proactive role, defining and enforcing rather detailed commercial rules for the players (e.g., U.S. and U.K. and Argentina). This may be compared with the regulator who takes a more passive role, leaving commercial decisions to the market players but enforcing nondiscrimination and preventing misuse of dominant market positions (e.g., The Netherlands and Germany). These are of course the extremes, and many countries have systems that fall between regulatory activism and regulatory passivity (e.g., Canada, Australia,).

9.42 To design a model most suitable for a particular developing or transition country, the policymaker must carefully weigh the givens of gas supply and demand. These include the geographical factors of a country, the stage of development of its gas industry, the size and distribution of its gas reserves and the stage of its openness to free markets and private investments. In designing the most appropriate regulation model for a country, policymakers should not expect or plan to leapfrog over decades of development experienced by long-established gas industries, even though many of the practical issues in building up a regulatory system are similar. Much as it is worth exploiting the knowledge gained through the latecomer's advantage, little can be gained simply by copying the current regulation models of states with large and well-developed gas industries, which may be far too elaborate for a developing country. Moreover, the number and location of gas resources relative to the market sites may be quite different in developing countries compared with developed economies. Also, the legal traditions should be observed, which may or may not tend toward more proactive or more passive regulation.

Regulation and State Involvement Adequate to the Development Stage of the Gas Industry

9.43 The regulatory framework should meet the needs of the emergent gas industry. It should not be over dimensioned and overregulated, but it should look toward the future.

9.44 Often, in countries like those in SSA a gas industry will start with a relatively uncomplicated arrangement—by supplying gas from one field via gas pipeline to a single power plant. Purely contractual relations might cover this. However, as the power plants as well as the other elements

in the chain are mainly in need of investment goods that must be paid for in foreign currency, soon the issues of currency exchange will come up, requiring the involvement of the state.

9.45 Except when the final value of the gas is realized in an export scheme, the likelihood is that some national company will be the last part of the chain that has to collect the money in local currency. The long-term minimum pay guarantee, in hard currency, that the gas-producing companies wants will be borne by that company and most likely be backed up by the government. To that extent, the government should have some idea of what kind of long-term gas contract it is prepared to accept and back.

9.46 These issues do not require regulation but very often require the involvement of the government, which will have to guarantee for the cash flow of the project, linking the cash flow of the project to international prices for energy goods. Thereby, the government will become an explicit or tacit partner of the deal, which will give the government some justification, to make sure, the contracts are in line with its own interests as a guarantor.

9.47 The government may have a vested interest in commercial gas deals, because the commercial agreements between large contract partners in the gas chain may have an influence on the government take. The best way to avoid this is to conceive the tax system so that the total government take is as neutral as possible to the commercial agreements in the gas chain—for example, by raising the government take mainly by a profit tax on all companies in the gas chain.

9.48 Another issue that arises at the contract level, is the question of conflict resolution. There are examples in which the national law (or the government) requires final settlement of disputes by the national judicial system. International investors will usually not accept this, due to a lack of handling with large disputes in a young national legislation and due also to an alleged bias of national jurisdiction.

9.49 An issue requiring economic regulation will arise if several producers want to use the same pipeline or pipeline route to supply plants at the same location. This raises the question of establishing access rules and tariffication for a pipeline. One way appropriate to emerging gas industries to deal with such access questions is to limit open access to the construction phase (e.g., by establishing a so-called open-season pipeline). In this model it is possible to participate as owner or through firm transport commitments in a pipeline project, which is open to all interested for a defined period or "season." In that period, everybody can decide to join the project on an equal basis sharing risks and chances. Later on access would be on a negotiated basis.

9.50 Investors in an initial gas and pipeline scheme may demand a period of exclusivity to use the infrastructure to make sure that their investment pays out. Countries may provide this by granting exclusive concessions for the operation of a pipeline for a set period to amortize a major part of the investment. But countries should examine such demands carefully to ensure that they are justified by the risks taken by the investor.

9.51 In view of the likelihood that gas producers will add consumers later on, the state should envisage possible extensions of the regulatory scheme right from the beginning.

9.52 Given the situation in countries such as those in SSA, it seems unlikely that a regulatory system will have to deal extensively with issues involving provision of gas to households. Moreover, small gas schemes, which are essentially limited and domestic in nature, might best be left to the entrepreneurial spirit in single cases. The more typical cases are the following:

- The case of a country that experiences a large growth of electricity demand and is involved in offshore gas production suggests that it is important to open the access to a pipeline from a first gas-producing field (offshore) to other adjacent fields to make as much gas available as possible. This applies especially to smaller satellite fields, the development of which on their own would not justify a pipeline.
- In rather typical cases in SSA, gas production is potentially larger than the market potential. As one or several large consumers would start the scheme, it might be important to open access to the gas to some smaller consumers. The larger producer may not be particularly inclined toward dealing with these smaller-scale consumers, because serving them may require involvement in a new type of business (e.g., low-pressure pipelines). They also may resist because the transaction costs may appear large and because the gas-producing company and the electricity company believe they can invest their resources more profitably elsewhere. In such circumstances, it is important that smaller consumers or any other entity with an interest in starting a gas development project cannot be blocked by the indifference of large producers or customers to smaller markets.

9.53 In an evolving gas industry, the sequence of development for larger fields will either be driven by demand from a power plant or from a producer of gas-intensive exportable goods (e.g., ammonia). These demand sources may then be followed in the marketplace by smaller industrial (e.g., cement, glass, food, and breweries) and commercial users (e.g., hotels, hospitals, and airports). By the time the market has such an array of gas consumers, some rules for their access to gas and protection from abuse of exclusivity should be in place. These protections may indeed be necessary—especially for the access question. The argument of the possible substitution by fuel oils for gas gives a protection on the price of the gas. However, the potential customers may be driven toward gas in first place not so much by the price, even if gas is sold at a price that is energy equivalent to a substitute fuel such as fuel oil. Rather customers may still show a strong preference for gas because of its easier handling and continuous flow, which give it advantages over fuel oil. The regulatory framework must make sure, that such demand cannot be blocked by misuse of monopolistic power.

9.54 In essence, first of all it is necessary to establish a stable and secure framework for investors who are supplying gas to mid- and large-scale consumers, and for ensuring that the framework is immune to major changes stemming from changes of governments. The regulatory framework should make sure that economic new projects—to open up further production and to supply additional consumers of gas at lower costs—have a chance to be realized. Main instruments are granting the right to build pipelines and, if necessary or helpful, defining access rules (inclusive of capacity enlargement) for existing pipelines.

Organization, Institution Building, and Staffing of the Regulatory Agency

9.55 The regulation of the gas sector requires different entities to play important roles. These entities include the government ministries, Parliament, and the regulatory agency itself. These roles must first be organized and assigned. Then, the institutional capacity building of the regulatory agency, which may be an entirely new operation in a developing country, requires particular care. Staffing is also crucial, and the capabilities of individuals such as chief regulators and members of boards of directors will have a significant impact on the power and influence of the agency itself.

Organization of Roles

9.56 To begin with, the division of labor must be clear between parliament, government, and administration and the regulatory agency Usually the different roles for each in the gas sector are allocated as follows:

- *Political role.* The government ministry responsible for gas and the Parliament play the key political roles, with the government bureau taking political initiatives in Parliament by drafting and proposing a gas policy.
- *Administrative role.* The government gas ministry has the primary administrative role of developing and maintaining legal/regulatory activities, managing information, and monitoring sector activity.
- *Regulatory role.* The actual execution of the regulatory framework (issuance of licenses, approvals, permits, and detailed regulation or supervision of a sector) is done by the regulatory body, which may also do some of the supporting work for the ministry (e.g., data collection and organization).

Institution Building of the Regulatory Agency

9.57 Corruption and inefficiencies lead to delays and higher costs and ultimately deter investors. The building of competent and efficient institutions is of high importance for the success of a gas project. Thus, when a regulatory agency is set up, the scope and the function of the regulatory agency has to be defined, and several issues must be addressed:

- *Separate upstream and downstream regulation.* Combining technical and economic regulation? With regard to technical regulation there may be many synergies between upstream and downstream because a lot of the technical issues are the same, except for the reservoir issues. On the economic side upstream and downstream are very different and the only argument to have both under one roof is of a practical nature. Combining technical and economic regulation may make sense, as the technical standards may have impacts on the economic regulation. A more practical argument would be that the regulated industry deals with a one-shop stop.
- *Multisector versus sector-specific agencies.* A sector-specific agency may develop more specialized knowledge. If only one or very few companies are to be regulated within a very small sector, then the regulating agency, risks being captured by the incumbent companies. In contrast, a multisector agency escapes that danger, because it may draw on the experience from at least two sectors. In addition, it may better coordinate the intersection between gas and electricity.
- *Independence of the regulatory body, independent source of funds.* In order not to come under political pressure over budgeting questions, the regulatory agency should not be funded in a way that is subject to political influence and change. Rather, law should define the agency's funding, so that it cannot be altered radically according to the political motives of incumbent parties or officials. This can be accomplished by deriving the necessary funding from a levy of the industry regulated.

- *Agency's functions clearly defined.* For example, elements needing clear definition are regulation of tariffs and access, for what part of the gas industry, settlement of disputes over those questions, and rights of access to information.
- *Dispute settlement procedures.* The settlement procedures in place for disputes with the regulatory agency should be clear. The appeal procedures should likewise be clear; an ultimate appeal should be possible *outside* the agency (e.g., through the court system).

Staffing

9.58 The efficiency of the agency depends very much of the staffing with highly qualified personnel and of the right internal organizations of the processes in the agency: These questions include

- *Board of directors or single director?* The first option may give a more balanced view, but the second may lend the agency more clout, especially if the regulator is a strong personality. On the other hand, an incumbent company may more easily capture a weak single regulator. Given the role a director or directors play in implementing the gas policy of a country, the individual or group should be drawn from the pool of public servants elected or appointed by Parliament/government.
- *Term of the director(s).* This should be beyond or at least not synchronous with elections. If an agency has more than one director, the terms should be staggered to provide long-term continuity and institutional memory.
- *Professional staff.* The staff for technical, legal, economic issues should be hired from the market, if possible. This implies paying the market rate for such staff.

Publicity

9.59 The regulatory agency should keep the public informed about the main issues. This should imply open procedures, as well as public hearings on the issues, which are to be decided by the regulatory agency. Resolutions should be made public. The agency should also advertise its own work in an adequate positive way.

10

Structuring the Industry

10.1 When an economic project is identified, it is up to the state to define the rules of the sector and the entities that will be permitted to participate—that is, how many and which participants should be allowed to enter the different parts of the gas chain. Also to be decided is whether a single company should be permitted to involve itself in different parts of the gas chain. The state must also decide whether and to what extent it or its local organizations, such as municipalities, should be involved in the operating companies in the sector.

10.2 In determining which roles should be assigned in the sector, and how the economic gains (opportunities and risks) should be distributed, the state must solve several partly interwoven issues: How many separate elements should the gas chain have? How many companies should participate in each element of the gas chain? Is cross-ownership possible (i.e., one company of the chain holding shares in another company of the chain, or even two companies engaged in different stages of the chain mutually holding shares of each other)?

10.3 The state may make its decisionmaking simpler if it allows a single company or group of companies to cover production, pipeline transport, and supply of the large gas customer. This may be justifiable if there is no chance that other participants will enter any stage of the gas chain. That would imply, for example, that contractual interfaces between the stages of the gas chain are not necessary and might even be artificial (e.g., a gas field, a pipeline to shore to be used in an ammonia project with no gas market anywhere in sight). However, in anticipation of a later more sophisticated stage of the gas industry that may require more regulation, it may be wise to install separate companies or at least separate accounting for each stage of the gas industry right from the beginning.

10.4 The general situation, however, will be to have different companies involved, resulting at least in one real interface. It might still make sense to integrate production and pipeline (e.g., a single offshore field together with the offshore pipeline to land the gas on one side and a large market directly near the landing point on the other side). In general, allowing for separate companies for the different stages is the best solution, with or without cross-ownership, once real alternatives exist at the interfaces between the different stages.

10.5 Whether or not the state allows a significant degree of concentration in the market, it may well be worthwhile to undertake a professional search for development partners for a new gas project. This would help ensure that the potential participants have been informed and that the "market" for partners has been appropriately exploited. Professional advice should also help to choose companies (e.g., by organizing licensing rounds and bidding procedures).

10.6 Together with the structuring of participation, some additional rules for allocating risks and opportunities should be decided. Apart from the pattern for the upstream company, which is set by the production license or production-sharing agreements, a main point for setting up a gas industry is to deal with the risks and opportunities of the gas pipeline. If a separate pipeline company is set up, government policy might be guided by channeling the price risks and opportunities of marketing the gas back to the producing fields where the risks are, and correspondingly by having the transportation system organized as a low-risk, low-profit entity (if backed up by throughput contracts).

10.7 If the operation of the pipeline is combined with the marketing of the gas (merchant pipeline), this merchant pipeline might take all chances and risks in the marketing of the gas and not be subject to mandatory third-party access to its pipeline infrastructure for a definite time. This would be intended to compensate for risks undertaken. This time range could be defined as a span of perhaps 10 to 15 years, which is straightforward, or in terms of recovering or amortizing the capital spent or even by looking at the cash flow reinvested. The interface between the merchant gas pipeline and the gas producer as well as the interface between the merchant gas pipeline its customers would usually be the subject of negotiations between partners of about equal negotiation power. The interfaces would therefore be unlikely to prompt state intervention, apart from abuse of dominant market position.

10.8 Very important are the final gas consumers—in the beginning, power plants or fertilizer plants. Fertilizer plants are, or should be, subject to international competition. Power plants, however, will be subject to the regulation of the electricity industry for their output. This regulation and the role of the power plants (state company, IPP with a contract with the state company, or free-merchant IPP) will have a strong bearing on the whole gas chain. Gas utilities themselves also may be subject to national or municipal regulation, which would influence the whole gas chain. These rules should be transparent to the partners who want to enter a gas project.

10.9 Load management requirements for gas supply differ greatly depending on climate. Areas where heating has a high share of consumption may experience a very large seasonal swing. Such seasonal swings may also occur because of the link between gas supply for power generation and hydro-based power generation, which depends on seasonal variations of precipitation. However, countries such as those in SSA are more likely to have swings in demand caused by social patterns, such as working hours, weekends, or cooking and eating habits. These short-time variations in load may be managed by peak-shaving facilities; given the lack of suitable storage sites in SSA (so far neither emptied fields nor salt domes are known near potential consumption centers). In this case, it is primarily the pipeline company and the producer who must manage larger variations in demand; however part of the load management can also be taken care of by fuel switching. The precise arrangements are best left to the market participants.

10.10 As mentioned earlier, to the extent possible, the state should leave the commercial and operational issues to the industry, which better responds to these tasks. However, there might be cases in which the state should participate as an investor (e.g., if otherwise not enough investors are involved to make an economic project, despite reasonable commercial conditions). This might be necessary or reasonable if the state has to take certain risks that private companies do not want to take or if the companies have much more attractive projects, in their terms, in other countries. However, if a state company is created that participates in any part of the gas chain, that company should concentrate on the commercial role. The state should restrict itself to the role of a shareholder, ensuring that regulation is performed by a separate entity that is politically and economically insulated from the operational side of the sector. The state's commercial entity should be treated like any other private company with regard to

taxes, regulations, and so on. The question should also be kept in mind of how long a state-owned company is useful or necessary, or when it is best privatized.

10.11 On the municipal level, an argument for a participation by the municipality in a utility might be that a gas infrastructure is just one of several grids and infrastructures whose development should be part of a holistic approach to urban development. That approach might justify participation by a municipality in companies whose roles are crucial for the city's development.

10.12 Developing a gas industry also provides some important opportunities. Countries may well want to use their participation in the sector to create or bolster national competencies and labor markets—for example by creating a national industry for the production of gas appliances, meters, and gas-related services. Although these companies are not direct links in the gas chain, they may play an important role in fostering a gas industry as well as in realizing the environmental benefits of gas. As no principal barriers prevent entry into such activities, the state should constrain its role to defining and implementing reasonable safety and environmental standards.

The Gas Chain

10.13 Unlike oil development, where the different participants are linked only very loosely, gas operations link the participants in the gas chain rather tightly. In oil, all those involved may chose their role, shape that role as they like, and test it out. In the gas chain, in contrast, the roles of the participants should be coordinated, at least in an emerging gas industry. It makes some sense for the state to sketch some ideas on how the different roles should fit together. This is outlined in the subsection Roles of the Participants in the Gas Chain.

10.14 Unlike oil, where sales are single acts by nature, gas is characterized by long-term cooperation. Although gas sales will be negotiated individually between the members of the gas chain, the state may have reasons to have knowledge of the basic provisions of the sales contracts. This holds true especially when the state in the last instance is guaranteeing the income in hard currency. Some elements of the main type of contracts are explained in the paragraph on contracts. Also, some points on joint-venture contracts are discussed that are necessary if several companies work together on one stage of the gas chain.

Contracts to Link the Elements of the Chain

10.15 The gas chain is held together by contracts that are freely negotiated between the large participants. Which specific contracts must be concluded along the different parts of the gas chain? Unless two parts of the chain belong to the same owner, a contract is needed to define the relationship between those parts of the chain. And even if two parts of the chain are under the same ownership, it may be advisable to have contracts between the subsidiaries or—in case the activity is handled by the same entity—to have different accounts to facilitate clear accounting for possible sale or "unbundling" of one of the parts of the chain later on.

10.16 Remember that in the "tight" gas chain, the product and the delivery risks are tight from one participant to the next; and in the other direction, the payment and the payment risks are tight. The failure of one link in such a chain has implications for all elements of the chain, as neither the upstream nor the downstream participants can easily find new partners. Therefore, risk mitigation along the chain is much more important than in the daisy-chain arrangement typical of an oil chain.

10.17 Contracts may also be concluded between the state and the companies (e.g., for licenses for production, transport, or distribution). Between the companies on one level of the gas chain, if they are sharing the same entity (e.g., several owners of the transportation company or of the power plant), joint-venture agreements are necessary. If parts of the gas chain are strictly regulated, then contracts will be concluded according to the regulatory blueprint, leaving little to be negotiated; often the names of the contracting parties merely have to be inserted.

10.18 Often contracts are sufficient in the beginning—instead of a regulation—when only a few participants are in the market. In any case, the initial large-scale participants rarely need a regulator for relations among themselves. The regulator's role is primarily to protect the small-scale participants, who might come into the market only in a second phase, in which a gas industry expands beyond the initial large customers. To promote the development of that second phase, however, some basic concepts for later regulations should be fixed at the outset.

Sales Contracts between Producers and Buyers

10.19 Typically, the producer of the gas will look for a long-term contract with a minimum-pay obligation, where the price is linked to some internationally traded energy denominated in dollars, with a conversion guarantee if not directly paid in dollars. The contract should include an international mechanism for settlement of disputes. The buyer will look for a contract that defines clearly the obligation to make available the gas or at least to give the buyer a priority on the available gas. The price should allow the buyer to sell the gas or to generate electricity profitably from it.

10.20 Given the long term of such contracts, it has proved useful to include some clauses that allow for renegotiation periodically (three years is usual) or under substantially changed circumstances. At the heart of successful long-term contracts is creating trust between the parties involved. The aspects of long-term gas contracts are described in detail in ESMAP report 152/93 ("Long-Term Gas Contracts: Principles and Applications").

Agreements Entered into by the Participants in the Gas Chain Other than Gas Sales Agreements

The Producer

10.21 The usual necessary agreements are production-sharing agreements or license agreements between the producers and the state, joint-venture agreements between producers participating in the same project, and operator agreement between the joint venture and a chosen company performing the operations on behalf of the joint venture. These are well known as part of the oil industry, although in most oil agreements, gas-specific issues are not dealt with, which leaves some uncertainty about how to deal with gas. This is of course more difficult than for oil, as the market for gas is not immediate. However, a few issues should be addressed explicitly. These include how to keep flaring or venting to a minimum; how to find and develop a domestic market; and whether the ownership of the gas should be automatically that of the government.

The Pipeline Company

10.22 The pipeline company can be the same as the producer, or it can be composed of several companies, including the producer. If more than one partner is involved in such a venture, an owners'

agreement is needed as well as transportation agreements between the owners and eventually between third parties and the joint venture. These agreements should define whether it is possible for third (or additional outside) parties to have access to the pipeline, unless that access is in any case regulated by a state authority.

10.23 The transporter will build and operate the pipeline or several pipelines either for its owners plus shippers who have made agreements with the pipeline company or as an open-access pipeline. When the pipeline operates as an open-access pipeline, then the pipeline is deliberately or by regulation prepared to transport for third parties according to published tariffs and conditions that may differ from the owners' tariff, because of the different assumption of risk by the parties. The basis for the commercial consideration for a pipeline in developing gas industries is defined by the volumes determined by the original scheme—meaning the original field development or the original market. Any access of other parties can only be taken into account as upside potential, which may justify building the pipeline to a bit larger diameter (e.g., 2 inches larger). Cases in which a pipeline has been built anticipating enough transport demand by third parties to make the pipeline profitable are hardly known. That is, the building of pipelines has been driven and promoted by gas producers themselves, who needed the pipeline to sell their production, or by gas marketers, who needed the pipeline to get access to supplies. Companies involving themselves solely in the business of building pipelines—without having a stake in supply or demand or at least being backed up by a throughput agreement—are rare exceptions in developing markets.

10.24 For offshore provinces or inland gas provinces, it is common that the companies that have prospective fields will join the pipeline company, which develops the province, provided they see opportunities to market the gas.

10.25 Usually a large part of the financing of the pipeline is backed by ship-or-pay agreements of the gas producers, which make the pipelines from the field to the delivery point to the customer into a commercial appendix to the field. That is, the task of the transporter in such cases is to construct, finance, and operate the pipeline. If the pipeline takes more risks, it should be free to optimize its commercial advantage. It might try to acquire as much transportation as possible (which seems difficult when the gas market is the bottleneck). Or, it might seek to buy and resell gas on its own account and risk as a merchant pipeline.

10.26 The transport owners' agreement will be similar to other joint-venture agreements and will cover the following points:

- Objectives
- Description of the transportation system
- Formation of the joint venture
- The management committee
- The operator
- Financing
- Purchase of goods
- Work program and budgets
- Rules to increase capacity and allocate it.

- Insurance
- Transport obligation (for the owners)
- Tariff and payments
- Accounts and auditing
- Legal issues.

The Customers

10.27 The gas purchase agreement is only one—albeit a highly important—element of the economic activity of a gas-buying company. Other contracts will shape its economic activity, which will be closely linked to the gas sales agreement, either because the gas purchase agreement is an important basis for the economic activity or because the gas purchase contract refers to the contracts of the company (e.g., for volumes and prices). The following subsections touch briefly on some important aspects of contracts that have a feedback on gas sales agreements for different types of customers.

Export Projects

10.28 A gas industry may be started by an export project. The investor should then be familiar with the marketing side of the product on a world market—for example, ammonia. The price paid to the gas supplier will usually be a netback from the ammonia price minus the costs of the ammonia production. The gas buyer (the ammonia plant) may thereby want to turn over the price risk of the ammonia market price development to the gas seller, whereby the gas seller would become commercially dependent on the ammonia market. At least this would refer the gas producer to a world-market price in hard currency. Volumes would be basically constant, with a high load factor.

Chemical Industry / Refinery

10.29 Pricing to chemical industries or refineries would be against fuel oils and should be relatively straightforward, as a chemical plant or a refinery would be the end of the value chain, where a comparison with an internationally priced product may take place. Volumes would be basically constant, with a high load factor.

Power Company/IPP

10.30 The difficulty with sale of gas for power production is that the tight value chain does not end with the sale of the gas to the power plant. Rather, the final value of the gas is only realized after the sale of electricity produced—for example, the sale of power by an IPP to a state-owned power distribution company and then to the consumer, who pays in local currency.

10.31 In considering how to maximize the value of gas sold for power production, the developers may wish to consider what kind and what size of gas power plant should be built. Gas power plants come in standard designs and certain standard sizes (e.g., either a gas turbine of 100 MW or the next largest size, about 250 MW). Should a CCGT be built or a gas turbine? It is possible to build a gas turbine first, amending it to a CCGT later. That would improve efficiency and thereby electric output, but it would not increase gas consumption. In some cases, one might even use an existing steam condensing plant and add a gas turbine in front to make it a CCGT.

10.32 On the volume side, the operator of the power plant will be interested in flexible but long-term, reliable supplies. Volumes needed may not only depend on variation of demand for electricity, but on the rank of the power plant in the merit order (i.e., on the marginal costs of electricity production). That makes it rather difficult for a power plant operator to handle the high minimum pay volumes, usually requested by the gas supplier, unless he is paid for the electric power (capacity) made available or has a sales contract for the electricity produced with a minimum off-take.

10.33 IPPs have become common these days. The IPP would take construction and operating risks and would provide the financing of the power plant. To the extent that the IPP is selling directly to customers, the IPP also takes commercial risks. But usually it is the customer of the IPP who takes the commercial risks. Often, it is the national grid company that guarantees a minimum off-take, a price in dollars, or a price in national currency corresponding to an international price in dollars with currency convertibility guaranteed by the state. In that case, the IPP will make sure that the power sales agreement reflects the conditions of the gas-purchase agreement and vice versa, in order to avoid any risk gap.

10.34 Even if the national electricity company takes the main marketing and currency risks, an IPP project must be well managed and needs careful contract design as well as careful mitigation of risks.

10.35 The following are the necessary activities/contracts to be concluded for the building of a new power plant independent of whether it is by an IPP or a traditional national electricity company:

- Contracting the gas
- License application for the construction/operation of the power plant
- Environmental impact study
- Financing
- Lend lease agreement
- Procurement of power plant
- External relations (e.g., with nongovernmental organizations).

10.36 An IPP would have to arrange, in addition, for the following:

- Joint venture agreement if more than one company is involved
- Selling the electricity
- Arranging transportation of the electricity (may not be necessary if the electricity is sold directly into the grid)
- License application for the construction/operation of the power plant when the power plant is run as an IPP.

Distribution Company / Utility

10.37 Local entrepreneurs that want to use gas that is already close to larger consumers may be the most proactive in trying to create the distribution of gas (usually at a lower pressure) beyond the large consumers, which are supplied from the high-pressure grid. They may have more individual contracts or rather standard contracts with their customers. Very often, the contract may just concentrate on the notion that they deliver gas as long as they get paid for it.

10.38 In case of a more developed distribution company, the question of generally applicable tariffs and of their regulation comes up. However, the likelihood of developing gas grids of the kind typical of Europe or North America is slim in countries such as those in SSA, because of the climate and the lack of general need for space heating.

11

Risk Mitigation and Financing

Risk Mitigation

11.1 In addition to the normal risks of any project, such as construction risks and risks of underperformance, projects in developing countries have particular risks that need to be mitigated. These risks may stem from unclear policy, deficiencies in the institutional framework, the lack of clear and transparent legislative and regulatory systems, or economic and political insecurity. These aspects apply especially to gas projects, as their value chain is firmly linked to the country.

11.2 As a general rule, risks are best—and most cheaply—borne by the parties influencing this risk. For a gas project, these risks and their most appropriate bearers are as follows:

- *Construction risk*—by the construction company
- *Operating risk*—by the operator
- *Financial cost risk*—by banks
- *Reserve risk*—by the oil/gas producers
- *Revenue risk*—borne either by customers to whom costs are passed or by the producers (netting back the market price for gas to the producers).

11.3 These risks are common to gas projects worldwide; they should not need special consideration in developing countries. However, the following risks are typical for developing or transition countries:

- Political / country risks
- Regulatory and transfer-of-profit risk influenced by government
- Risk of shortfall in revenue or margins because of market risk—especially nonpayment and nonlinkage to international energy prices and uncertainty about convertibility.

11.4 These risks are specific for developing countries and for gas and need careful consideration and mitigation. Otherwise, the members of the gas chain will ask for a higher return on investment than elsewhere, contributing to making the project noncommercial. The risks must be kept as

low as possible to reduce the risk spread for the financing, which might turn an economic project noncommercial.

11.5 The most important risk to an international investor seems to be the risk linked to failing to realize the income from the project in line with international energy prices in hard currency. The main way of mitigating such a risk for an international investor is for the government to declare irrevocably (e.g., by law) that the final tariff for the gas or the electricity will automatically reflect either the costs incurred or the price of the competing fuels at international levels. This adjustment would have to be accomplished without delay, and the resulting income would have to be capable of being transferred into hard currency.

11.6 Additional steps to mitigate those risks would be to mobilize as much as possible national private capital to keep hard-currency financing low. In addition, risks may be mitigated by government involvement, either as a shareholder with equity or as a provider of back-up guarantees. Also, some of the international financial institutions may become involved by providing finance or equity in projects that may be backed by government guarantees, thereby mitigating the risks.

Financing

11.7 Project finance depends on identification of project risks, analysis of mitigation strategies, and allocation of risks. Good risk mitigation may reduce costs of financing and contribute to the commercial viability of a project. Ultimately, this amounts to financial engineering (the practice of combining various instruments for guarantees, borrowing, and mobilization of equity), which is the heart of project finance. The details of financing will not generally be important before one has identified a project that is economic and financially viable. But once a project is viable, one ignores the intricacies of financing at one's own peril. Some basic terms and concepts are as follows:

- *Full-recourse financing.* As loan security, lenders have recourse to the assets/revenues of the entire company.
- *Limited-recourse financing.* Until the project passes final completion test this is like full recourse; after that, it is like nonrecourse.
- *Nonrecourse financing.* This is essentially off-balance-sheet financing. That is, the debts do not affect the balance sheet of the borrowing company. Instead, the project risk is borne by the lender, whose collateral is from the project itself, usually either reducing the percentage of overall costs so financed or increasing the interest rate to reflect the extra risk.

11.8 In the financing of a project, the sponsors contribute equity (typically 20 to 40 percent of project costs). Sources of equity are usually as follows:

- Sponsors' own capital and subordinated loans
- Multilateral institutions
- International equity market
- International Finance Corporation
- Local capital market

- Certain investment funds
- Governments.

11.9 Project debt (typically 60 to 80 percent of project costs) is secured through assets and through income from the project. Sources of debt are usually as follows:

- Institutional investors
- International commercial banks and local banks
- IBRD and regional development banks
- Government-guaranteed, official loans from multilateral institutions, regional banks
- International and local bond market
- Suppliers' credit, loans by export agencies
- Specialized energy funds.

11.10 Financing schemes have developed remarkably from the 1970s to the 1990s. The schemes for financing gas projects in the 1970s and 1980s typically involved financing through international oil companies on the basis of their internal cash flow. Little borrowing thus was necessary, although governments did begin to become active in financing their own national hydrocarbon companies.

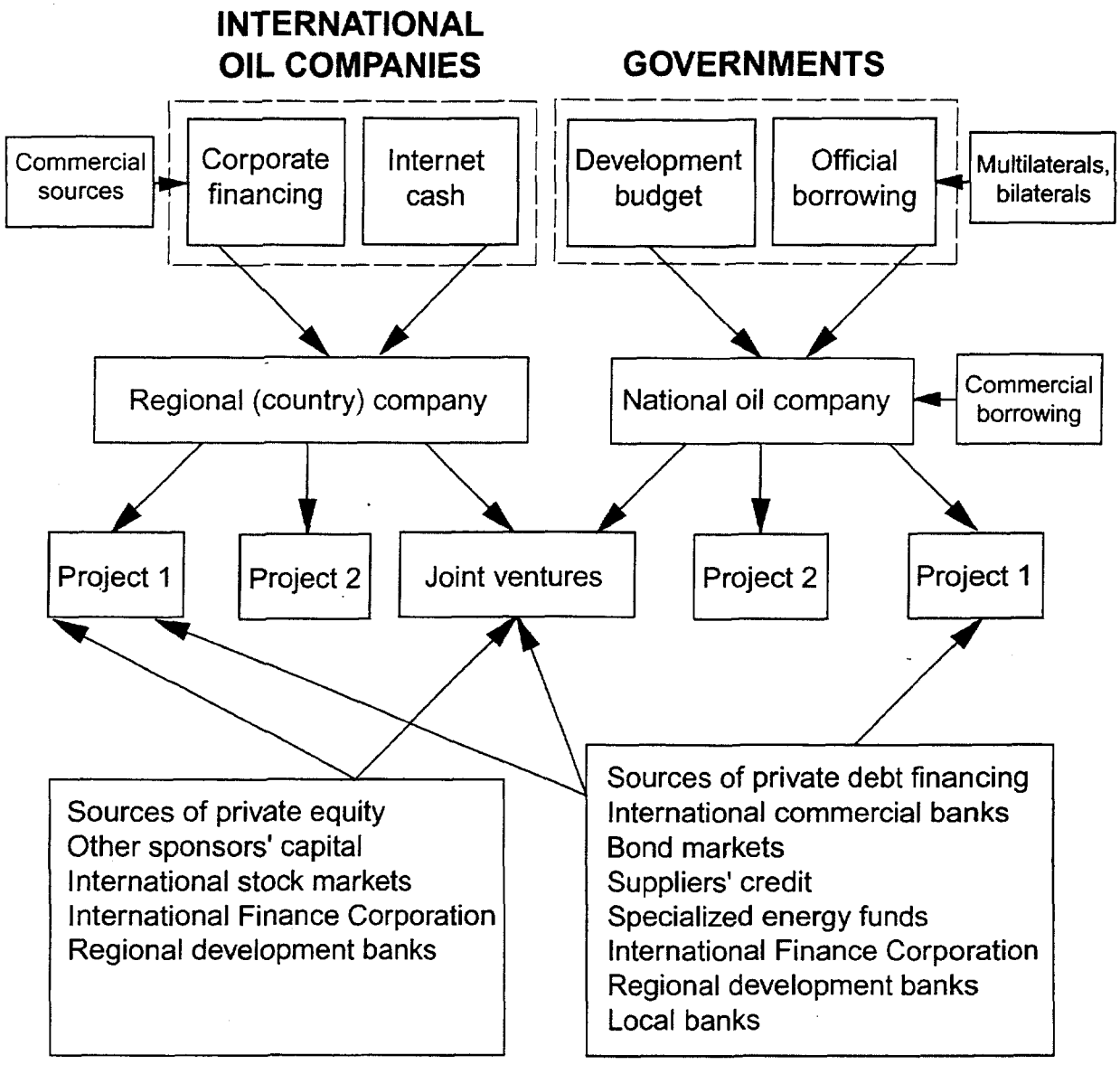
11.11 During the late 1980s, after the collapse of oil prices in 1985–86, the sector saw a number of changes. To begin with, the international oil companies began to establish tougher profitability requirements. For their part, the oil-exporting countries were less willing or able to finance development in the hydrocarbon sector. In addition, governments worldwide had less money on hand, and the role of the state in economic activities underwent a general paradigm shift. On the other hand, more private capital was available, and private investment in emergent markets boomed.

11.12 The 1990s present a more complicated picture (Figure 11.1) for financing, characterized by the following features:

- Likely structures are joint private/public ownership
- Increased complexity, new sources of funds
- New actors—IPPs and smaller international oil companies
- Use of nonrecourse financing
- Major oil companies may accept local partners to spread risks and prefer internally generated funds, except for large projects or internal country limits.

11.13 The budgetary situation of most SSA countries remains precarious. The trend toward private financing of infrastructure has intensified. However, all partners involved are becoming more pragmatic, provided that the project is good and the framework is right.

Figure 11.1: The Complicated 1990s



12

Conclusion

12.1 A main issue for most developing countries is to provide clean, commercial energy to their population, to give people a greater range of energy choice, and to reduce pollution. Driven by environmental concerns, gas has become the premier energy source in the Western countries. However, in developing countries, traditional kerosene and even more so LPG also may lead to a substantial improvement of air quality that is comparable to that provided by natural gas. Even with regard to CO_2 emissions, the use of kerosene and LPG is a large improvement over biomass fuels. Gas oil might also be a good choice for clean, decentralized, and efficient power generation. As long as the development of a gas project is not economic compared with equivalent alternatives, it cannot be forced by the best incentive schemes, and it should not. However, when gas is available as a national resource, then all efforts should be made to establish its commercial utilization for the benefit of the country and its population—even more so if the gas would otherwise merely be flared.

12.2 This issue—the appropriate and effective development of natural gas resources, industry, and uses—was the subject of a workshop organized for participants from Sub-Saharan African countries by ESMAP in cooperation with Petrad in Nairobi from 23 to 26 June 1997. The subjects of generic nature from the seminar are discussed in the main body of this publication; the SSA-specific subjects are treated in Annex A.

12.3 The main conclusion on the subject is that commercializing of gas is a two-stage process, where the first stage requires identifying economic projects (by a cost/benefit analysis). If that can be done successfully, the second stage requires defining a gas policy and regulatory framework that can attract long-term investors while retaining—to the extent possible—the benefits for the country and its population. The two stages are elaborated below; they are listed in the recommended order and can also serve as a basic checklist.

Stage 1: Identifying Economic Gas Projects

12.4 Several factors must be observed in identifying economic gas projects:

- A gas source having a large enough supply potential is the obvious precondition.
- However, gas projects are driven by demand rather than by production. Gas without a paying demand does not have a value per se. Proving gas reserves is just the beginning.
- Environmental externalities should be part of the economic analysis.

- Gas is characterized by "lumpy" up-front investment; the dominant parts of the costs are independent of actual throughput. To be economic, gas off-take should have a steep build-up of gas volumes sold in the beginning, such as to supply power generation plus perhaps fertilizer production. A steep build-up of gas demand may also be prepared by building up customers that could switch to gas, once it is available.
- Gas transportation has large economies of scale (depending on pipeline diameter) in the planning stage. If a certain pipeline diameter is economic based on established demand, one should consider building a larger pipeline for the potential extra demand, using the economies of scale provided enough reserve potential exists. Once a basic gas scheme has been established, gas demand tends to take off. Also, once the economic supply to an area is established by large gas consumers, smaller gas consumers can be tied in economically.
- Transport of gas in classic steel pipeline needs large volumes to become economic—on the order of 100 million m^3/year. However, the use of a plastic (polyethylene) pipeline does offer good economics for volumes of about 1 million m^3/year for a distance of about 100 km. Although large demand volumes are usually needed to make gas projects economic, the potential of small projects should be explored.
- The investment is dedicated to specific sources and markets and can hardly be used otherwise. The economy of gas projects depends on distance—that is, country-specific geography—unlike oil, which can find markets everywhere, or electricity, which can be produced everywhere. For gas, one must look at the possible combinations of supply and demand to find out if economic projects exist.

Stage 2: Commercializing an Economic Gas Project

Once an economic gas project is identified, the challenge in commercializing that project is to define a policy and a resulting regulatory framework that is attractive to the investors and that benefits the citizens of the country. The key factors follow:

- As a first step, countries should define a realistic gas policy that is backed by a consensus of major parts of society. The macroeconomic impacts must be carefully assessed and managed. This requires a sober analysis of the situation to avoid wasteful decisions based on excessively high hopes.
- The gas policy should be made known to all potential investors and all stakeholders. However, one should avoid creating excessively high expectations about the economic rent created by a gas project and gas distribution.
- The state generally no longer plays the role of the operator of such projects, as this has proved inefficient in most cases. Private investors are best suited to handle these roles. The state should play a role in creating interest in a project by potential investors and in defining the rules for the participants. If the state exceptionally participates as an investor, it should clearly separate its functions as an investor and it policy and regulatory functions.
- The state should define rules for all participants by adequate legal and contractual instruments, attractive and clear to all players. This includes the interest of the state's

citizens with regard to safety and environment. It requires transparent and open process for all stakeholders to participate in the decision making process. A special issue is to make sure that the environmental benefits of gas are realized, be it by regulation or by incentive schemes.

- The state should create a reliable framework for investors to feel comfortable with the long-term investment in gas. This should include taxation and other government revenues, technical rules and standards, and economic regulation.
- Economic regulation should be adequate to the shape and stage of the gas industry. Avoid overregulation; avoid trying to leapfrog developed gas industries; and avoid copying complicated or excessively sophisticated regulation models. However, keep in mind the further expansion of the gas industry.
- "Musts" include legislation on contracts (consequences if contracts are not kept), conflict resolution in last instance by an independent third party having experience and international acceptance in handling large international disputes, and security of repatriation of profit and capital for investors.
- Gas schemes in countries with an emerging gas industry tend to start with relatively few large participants that may deal between themselves by means of contracts without regulation. Regulation should, however, make sure from the beginning to provide for access to gas transport or gas supplies for smaller gas consumers to avoid blockage of economic gas applications by large participants.
- The right financial engineering may be decisive to improve the project's economics and to create trust in the project.

12.6 A crucial point to attract international investors will be to assure them of their ability to realize the income from the project in line with international energy prices in hard currency, especially with regard small customers, who are typically subject to regulation. The main way of mitigating such a risk for an international investor is for the government to declare irrevocably (e.g., by law) that the final tariff for the gas or the electricity will automatically reflect either the costs incurred or the price of the competing fuels at international levels. This adjustment would have to be accomplished without delay, and the resulting income would have to be capable of being transferred into hard currency.

***

12.7 Gas will bring the benefits of a clean fuel to a country. The build-up of a gas industry should be sponsored by the state, but the implementation is best left to private investors.

12.8 Gas is a long-term business, requiring long term commitments—often lasting more than 20 years—for all parties involved. The main challenge for the state is to win the trust of the investors that the state will guarantee the long-term attractiveness of commercial conditions while realizing a fair share of the revenue and benefits of the project for the population of the country.

12.9 At the same time, the investors have a challenge as well, if they hope to remain a significant, enduring presence in the project: they must convince the country and its population that they are investing not for quick, cut-and-run profit-taking but for long-term development of the industry and the country.

12.10 Given the intrinsically long-term nature of gas developments and deliveries, it is crucial to have a clear but flexible framework governing the relationship between the country and the gas project investors and operators—one that includes a clear and effective mechanism for resolving conflict. However, above all, the parties involved should have not only the courage to invest in promising projects but also the courage to build mutual trust through sound practice, cooperation, and good will.

Annexes

A

Potentials for Gas and Status of Projects in Sub-Saharan Africa

A.1 Annex A briefly describes the situation of SSA with regard to the utilization and valorization of its gas reserves seen from the point in time of the workshop (i.e. the mid-1990s). The situation of the market for gas in South Africa as studied and presented by SADC is then described, and the status is given of three of the most important gas projects in the Southern part of Africa—the Pande project in Mozambique, the Kudu project in Namibia, and the Songo Songo project in Tanzania.

A.2 Even though some basic problems remain, some positive developments have recently transpired in SSA. The West African pipeline from Nigeria via Benin and Togo to Ghana has taken steps toward realization. In addition, hopes have risen with regard to finding more gas offshore the West Coast of Africa, which could justify an LNG export project.

A.3 A major challenge for establishing commercial gas projects in SSA is that the main demand for energy and electricity is concentrated on South Africa, where low-cost coal has a strong hold on the energy market. Moreover, only limited environmental penalties are applied to the use of coal, and the major energy companies are virtual monopolies. The result: opposition to large-scale introduction of gas.

Potentials for Gas in Sub-Saharan Africa

A.4 Gas resources and potentials present some distinctive opportunities and some special circumstances. Complicating the energy situation in SSA and the potential for large-scale gas projects is the fact that resources are unevenly divided and commercial energy consumption very unevenly distributed. South Africa, with a population of 40 million, consumed 94 mtoe in 1992, most of it—as just noted—from the burning of coal. The rest of SSA, with a population of 500 million, consumed a mere 44 mtoe

A.5 The total use of gas in SSA is currently about 5 bcm/year. The meagerness of this figure is evident when viewed against the amount of gas wastefully flared in conjunction with oil production by Nigeria alone—more than 25 bcm/year. (Nigeria and Russia, it must be said, lead the world in gas flaring.) For both developmental and environmental reasons, then, ample reasons exist for prudent development of clean-burning and efficient natural gas.

The Share of Gas in Primary Energy Consumption in Sub-Saharan Africa

A.6 A clue to the energy and gas situation of a developing country in particular is to look at the development of overall primary energy use and the proportion of commercial energy in it. In a next step one should look at the shares of the different sources of energy in the nation's balance of primary energy production and consumption. Commercial energy consumption in Sub-Saharan Africa grew by about 3 percent per year between 1975 and 1993 from about 70 million tons of oil equivalent (mtoe) to 105 mtoe. But the use of biomass has risen even more since 1975—from about 65 mtoe to about 115 mtoe. That rise has all the negative implications for a population suffering from indoor pollution caused by poor combustion and ventilation and from the deforestation and desertification that often accompany urbanization and poorly regulated and controlled biomass mining. Thus, the use of traditional energy sources such as dung, fuelwood, and charcoal has almost doubled and has risen to more than half of SSA's total energy consumption. This of course points to the strong need for affordable, clean fuels, even if natural gas may not be the solution in every case.

A.7 On a global scale, gas has come into increasing use; worldwide, gas reached a substantial 23 percent of commercial primary energy consumption in 1995. This growth was propelled both by the increasing appreciation of the comparatively benign environmental effects of gas use as well as the confidence engendered by ever-increasing proven world gas reserves. In Sub-Saharan Africa, gas consumption also multiplied several times in the period 1977–93, although it must be acknowledged that it rose from a very modest starting level (in 1995, the share of gas in commercial primary energy consumption in SSA was still minor, just 5 percent of total energy consumption (including noncommercial fuels, it was just 2 percent).

The Gas Reserve Basis and Gas Production in Sub-Saharan Africa

A.8 Africa as a whole appears to have fairly substantial proven gas reserves, and significant portions of these reserves are in Sub-Saharan Africa. Exploration has augmented the confirmed gas reserves of Africa substantially over the last 20 years. By the mid-1990s, SSA had 3,700 bcm of proven reserves, of which 80 percent were in Nigeria. Usually an LNG project needs a gas reserve basis of about 200 bcm. At present, except in Nigeria, gas reserves in SSA are probably not close enough to that 200 bcm figure to justify an LNG project, but they are still large enough for gas projects to become economically viable in several countries, once a large enough gas demand is within reasonable transport range of the production points. In the mid-1990s, some 50 percent of the gas were nonassociated gas. In SSA, gas reserves are increasing along with, but faster than, oil reserves. Unfortunately, this could discourage further exploration for hydrocarbons, as long as the gas found cannot be commercially disposed of because of lack of marketing possibilities and absence of a clear and reliable framework.

A.9 Apart from the smallness of the potential markets for gas, which result in high specific costs, additional costs of developing and marketing gas reserves in SSA are caused by the fact that a considerable portion of reserves lie offshore. In West Africa, at least, these reserves are relatively close to shore and may be economic, as they are in Côte d'Ivoire, for example.

A.10 Today, exploration for hydrocarbons in SSA is still small on an international scale, involving only 20 of a total of 1,700 rigs operating outside North America. The lack of gas development in SSA is in a sense a chicken-and-egg situation. That is, because project economics may be uncertain, many gas fields have not been properly tested or delineated. On the other hand, economically viable projects may be within reach provided that the gas supply is large enough to reduce specific costs of gas supply. In addition, even if a gas project may be economic, private companies may not consider it

commercial because the country lacks a reliable institutional or regulatory framework or because the country's licensing rules or taxation scheme makes an otherwise economic project insufficiently attractive to the investor.

Gas Production

A.11 Gas production in SSA is small compared with the proven reserves. So far, the largest use is in oil-field operations—specifically, for power generation in the oil fields and for oil lifts from the reservoir itself.

A.12 Given the reserve basis in SSA, the question must be asked, Why is SSA lagging so far behind in gas production and use? It does not seem that SSA gas fields are on average more difficult in terms of the technical access to the reservoirs or more challenging to develop. (Some oil companies however do claim that in SSA gas is specifically difficult to reinject in oil fields with associated gas, which could avoid flaring) Also the factor costs to develop the gas fields should not be decisively higher. Obviously the difference must be on the marketing side and the institutional framework.

Gas Demand

A.13 Consequently, one must ask what can be done in SSA do to utilize and valorize its own resources? Looking at exports: Gas trade has a limited share of world gas consumption and is restricted to large-scale projects via large pipelines or as LNG to countries that use very high volumes of gas. LNG options are known to be especially costly, so their contribution to provide gas for SSA or to market gas from SSA is not imminent. The challenges of LNG projects are well demonstrated in the example of LNG exports from Nigeria, which took more than two decades to finally realize

A.14 Another way to valorize gas is to use it as raw material for fertilizer or methanol production or to produce black carbon ore for ore reduction. While fertilizers may be used domestically, the other products would be driven by export considerations. In any case the pricing would be subject to an international market.

A.15 Inland use of gas accounts for only 10 to 15 percent of the total gas production in SSA and is focused on five countries (Nigeria, Angola, South Africa, Gabon, and Côte d'Ivoire). Inland use of gas is mainly for power generation, though Mozambique and Senegal, in addition to the five main countries, make some use of gas in small-scale applications. In general, then, the building up or further development of national gas industry in SSA will most likely be driven by power generation.

A.16 Given the dominance of power generation for the marketing of gas, especially in Sub-Saharan Africa, one must first look at the overall demand for electricity in SSA. This demand increased considerably from 1971 to 1993. The largest share of the electricity demand in SSA is by far in South Africa, which has the largest share of coal in the mix of fuels.

A.17 Outside of South Africa, the annual per capita consumption of electricity is very low—less than 0.2 MWh compared with 4 MWh for South Africa and 8 MWh for the average in the states of the Organization for Economic Cooperation and Development (OECD). This low consumption rate is mainly a reflection of the low GDP per capita in SSA.

A.18 This is also a chicken and egg situation in the sense, that higher demand for electricity, which depends on per capita income, could make more gas projects economic viable, but on the other hand the economic development is hindered by the lag of reliable electric power.

A.19 The SADC study on the South African market for gas presented at the workshop came to the conclusion that a substantial potential for gas demand exists in South Africa in power generation but also in ore reduction and mineral benefication. A short summary of that presentation is given further down. Both the Pande field in Mozambique and the Kudu field in Namibia are potential candidates to supply the South African gas market. Summaries of the presentation follows.

A.20 Apart from South Africa further gas markets exist in SSA, among them the successful example of Côte d'Ivoire. Other countries are to follow. Apart from establishing sufficient demand, the regulatory framework must be right. An example, where this has been done in a convincing way, is the Songo Songo project in Tanzania, which is also shortly described further down.

SADC Study of the Economics of Natural Gas Utilization in Southern Africa

A.21 The study is the result of an effort initiated by SADC to support regional and national policy formulation for the development and utilization of natural and coal bed methane resources in Southern Africa. The available and relevant information was consolidated from the eight technical papers prepared by SADC.[1]

A.22 The study yields the following results:

- The potential gas market identified in South Africa appears to be substantial enough for development of a regional gas industry. The forecast demand indicates that a phased development of regional gas fields could be required.
- Supply from regional gas fields to markets in South Africa could be economically viable for a number of large-scale user applications, with mineral benefication, iron reduction and power generation proving to be the most interesting options. The success of gas in the general thermal energy market will depend on future economic growth, development in relative energy prices and government policy for gas utilization.
- The large difference in net economic benefits between a scenario of policy creativity and a policy vacuum scenario indicates that a supportive government and focus on regional cooperation, coordination, and harmonization might have considerable economic merit in the Southern African region.

The Pande Gas Development in Mozambique

A.23 With the end of the civil war in Mozambique in 1992 and the election of a democratic government in South Africa in 1994, a positive investment climate has developed in southern Africa.

A.24 The Pande Gas field is an onshore field that was discovered as early as 1961. Between 1961 and 1968 Gulf Oil drilled six productive wells in Mozambique. ENH (Empresa Nacional de

[1] "Southern African Gas Markets," "Southern African Gas Resources and Production Costs," "Gas Transmission," "Gas Supply Economics," "Gas Development Scenarios for Southern Africa," "Gas Requirements and Institutional Requirements for Gas Development in Southern Africa," "Environmental Aspects of Gas Utilization in Southern Africa," and "Regional Benefits from Increased Gas Utilization."

Hidrocarbonetos), the national oil company of Mozambique, drilled another nine productive wells between 1989 and 1996.

A.25 Proven gas reserves of Pande are estimated to be 2,200 bcf or 60 bcm. The total of proven and probable and possible reserves is estimated at 4,600 bcf or 125 bcm.

A.26 The established industrial and commercial markets in Mozambique are insufficient for the investment required to develop and transport Pande gas to these markets.

A.27 Opportunities for natural gas in Southern Africa exist in Power and Cogeneration, Process based gas consumers (mineral benefication/ ammonia, fertilizers, synfuel production) and in the commercial and domestic market. The South African market is attractive, but it already has a highly successful oil and chemical industry based on coal.

A.28 The market challenge for the marketing of Pande gas is to find a firm commitment of an anchor customer to ensure basic economic viability. Although LNG is a technical transport option for Pande gas, pipeline transport is cheaper for all relevant cases for Pande gas.

A.29 Agreements have been signed between Enron and ENH for a project, which foresees the development of Pande gas and its transport over 570 km to Maputo where it should be used to reduce iron ore in a steel plant with a projected steel output of 4 Million t / year. The total investment would be 1 Billion $ for the development and the transport of the gas plus another Billion Dollar for the steel plant.

A.30 The project has suffered delays in the time after the Nairobi seminar because of disputes over the interpretation of the agreements.

A.31 The small-scale gas project to use gas from the well Pande 7 to supply gas by a polyethylene pipeline for small power generation in Vilankulo and Inhassoro is described in Annex B.

Namibia's Kudu Gas Field

A.31 Namibia has a population of 1.5 million people scattered over an area of 824,000 square kilometers. Namibia is a democratic country that got its independence from South Africa in 1990. The people in general elections elect its government every five years. Windhoek is the capital city and the center of central government.

A.32 Namibia is a significant player in the international fishing industry and also in mining activities, which represents about 25 percent of GDP. Agriculture is the main economic activity and includes main crops such as maize, wheat, and millet. Beef production accounts for 85 percent of the nation's gross agricultural income.

A.33 Upstream exploration activities started in Namibia in 1973 and led to the discovery of the Kudu gas field in 1974. After Independence, the first license round was opened in 1991 and was followed by a second in 1994. Seven licenses, all offshore, were issued to seven international companies, two of which have withdrawn since. Six wells had been drilled by 1997.

A.34 The licenses are for international bidding. The duration of an exploration license is for 4 years and can be extended twice by 2 years each time. The license terms include training of nationals and an environmental impact assessment.

A.35 The government has created the Petroleum Exploration and Production and Petroleum Taxation Acts as well as a Model Petroleum Agreement as a basis for the negotiations with the oil companies. Petroleum regulations had been drafted at the time of the conference.

A.36 The Kudu gas field was discovered in 1974 by Chevron, which drilled a well (Kudu 1) 170 km west of the Orange River mouth in a water depth of 167 m at a distance of 130 km to the nearest landfall. The two gas-bearing zones of the Kudu field are in a depth of about 4,300 and 4,400 m.

A.37 Another 3 wells were drilled in 1987, 1988 and 1996 respectively. The testing of last one proved an estimated 5 tcf (130 bcm) and has drawn the attention of the international oil industry to Namibia.

A.38 Given the relatively small population of Namibia and the distance of the gas find to other potential markets (e.g. in South Africa), marketing of the Kudu gas is not an easy task. Shell, as the operator of the Kudu field, is evaluating the possibility of marketing the gas to a new 700 MW power plant to be constructed at Oranjemund at the Namibian/South African border as well the option of exporting the gas to South Africa to the power company ESKOM. Using the gas from Kudu for power generation in Namibia would forestall Namibia's need to import power from South Africa (so far, 50 percent of Namibia's power is derived from South Africa) and would make power production independent from rainfalls.

Tanzania's Songo Songo Field

A.39 The development of the Songo Songo field in Tanzania has been on hold for almost two decades. However , there seems to be some recent progress with regard to the approach to commercializing this gas project. To begin with, Tanzania provides considerable incentive for petroleum exploration in the country:

- Exploration period of four years with possible extensions of four and three years.
- Large exploration areas, each having 60 blocks of 5 x 5 minutes.
- Negotiable work program and economic term.
- Maximum participation of national oil company TPDC at 20 percent.
- TPDC has to pay income tax and royalty.
- Allowance for unrecovered exploration cost in Tanzania.
- No import taxes on equipment.
- No foreign exchange restrictions.
- International arbitration.

A.40 The Songo Songo field was discovered in 1974. It is located in the Tanzanian offshore coastal basin, about 25 km from the shoreline. Part of the structure can be drilled from Songo Songo Island. It has proven reserves of about 20 bcm and an overall potential of 31 bcm. After an initial project to market the gas to an ammonia and urea plant failed, the marketing of gas from Songo Songo seemed fairly advanced at the time of the seminar:

A.41 The different components envisaged for the project are as follows:

- The Songas Project aims to develop Songo Songo Island natural gas by pipeline offshore and onshore to Dar es Salaam for power generation to be built by Songas and for deliveries to a cement plant
- An additional PSC agreement to be concluded between TPDC (Tanzanian Petroleum Development Corporation) and Ocelot to explore for more gas to sell to third parties.
- A dual-fired power plant of 10 to 15 MW to be installed at Mtwara in the South and eventually supplied with gas from wells to be drilled at Mnazi Bay.
- Supply of water, gas, and electricity for residents of the Songo Songo Islands and electricity to 15 villages along the gas pipeline to Dar es Salaam.
- Strengthening of the Ministry of Energy and Minerals by technical and financial support for policy studies, capacity building, setting up a database, and so on.
- Strengthening of the power distribution system.

A.42 A structure for the main agreements has been set up consisting of the following agreements: Escrow Agreement, Hard Currency Agreement, Implementation Agreement, Power Purchase Agreement, Shareholders' Agreement, Ubungo (power plant) Complex Transfer Agreement, Songo Songo Facilities Transfer Agreement, Gas Agreement, Production Sharing Agreement, Gas Processing and transportation Agreement, Operatorship Agreement, Sinking Fund Agreement, Liquidity Facility Agreement, Declaration of Trust, Debenture, Loan Assumption Agreement.

1. Financing is being handled as follows:

   - The estimated capital costs of $332 million should be financed by 23 percent equity ($76 million), of which Ocelot Trans Canada (OTC) will provide $50 million; 5 DFI will provide $22 million, and TPDC and Tanesco will provide $4 million.
   - The remaining 77 percent comprises loans ($256 million), of which the World Bank will provide $194 million; EIB, $36 million; and SIDA, $26 million.
   - Terms of the loans are none to 5 years grace, 15 to 18 years repayment period (excluding grace period), and interest rate between 6.0 percent and 7.8 percent.

2. Risk mitigation is being handled as follows:

   - The government of Tanzania offered OTC a target internal rate of return of 22 percent on their investment in the Songas project. OTC will bear the implementation, operational, some reservoir risk, facility transfer risk, as well as the payment risk.
   - OTC will construct the project at a fixed cost and to a firm completion date. A target availability has been established, with penalties and bonuses for deviations.

- The Power Purchase Agreement includes a monthly capacity charge to cover the fixed costs of the power plant. An energy charge will cover variable costs, including the gas price.
- As the investors considered nonpayment to be a sovereign risk, the following measures were considered to be reasonably implemented by the government:
  - Implementation of the government's covenants under the Power Project Credit Agreement with regard to collection of electricity payment arrears.
  - Establishment of a funded liquidity facility to cover two to four monthly payments of the power generation capacity charge.
  - Songas may offset overdue payments from the power company TANESCO against payment to the government for the World Bank credit lent on to Songas.
  - Establishment of an Escrow Account in a local commercial bank to compensate OCT in the event, that non payments render the project inoperable.
  - Credit enhancement and currency convertibility mechanism to ensure that Songas will be paid for the electricity produced.
  - Terms for TPA to free gas processing and gas transport capacity have been established.

A.43 The Songo Songo project has suffered delays since 1997 arising from a dispute between the government and the Malaysian sponsors of another private power project. The latest news, however raises hope that the project will go ahead.

B

A Successful and Economic Small-Scale Gas Scheme: Supply of Pande Gas for Power Generation in Vilankulo and Inhassoro, Mozambique

B.1 The Vilankulo Project involved executing a small-scale project in the Pande-Vilankulo area of Mozambique to produce small quantities of gas from an existing exploration well, Pande-7, transporting the gas by polyethylene (PE) pipeline to Vilankulo, and constructing a natural gas power generation station to supply electricity to the village. It was the first gas scheme in SSA. The electricity from the project is supplied to the consumer at a price that is not subsidized. The availability of an electricity supply is quick to attract more local investments, especially in small industries and shops, and to improve living conditions.

History of the Vilankulo Project

B.2 As noted earlier, efforts to market Pande gas on a large scale to South Africa or to an iron reduction project in Maputo are continuing. Parallel to these efforts, ENH decided to investigate the possibilities of supplying natural gas to villages within reasonable distance from Pande in order to substitute for imported diesel used for electricity generation. As a result, ENH started in 1992 to supply gas, mainly for power generation, to the village of Inhassoro, which is close to the Pande field, and to the village of Vilankulo, which is at a distance of about 100 km. This is the Pande Gas Pilot Project. In a first step, the offices of ENH were supplied with gas. In a next step, gas from Pande was used to generate power for the electricity grid in Vilankulo and Inhassoro. Further expansions of the gas pipeline to the islands close to Vilankulo and Inhassoro and to potential gas customers in Vilankulo are under consideration.

B.3 For the supply of Vilankulo and Inhassoro, ENH selected the Pande 7 well because it was the closest well to Vilankulo and Inhassoro. The well was drilled in 1990, and after the installation of wellhead gas treatment facilities, well preparation was completed August 1992, with pipeline-quality gas available at about 90 bar.

B.5 The first part of the Pande 1 project consists of the following components:

- *Production.* Installation of a gas treatment facility at the Pande 7 well (X-mas tree, dehydration unit, pressure reduction and separator package, odorizer and metering

package, condensate accumulator). The facility has been in operation since 1992 with no major problems reported. The capacity of the treatment facilities is 6,000m^3/d.

- *Transportation*. Installation of a 100 km buried high-density polyethylene pipeline from Pande 7 to Vilankulo with a spur line to Inhassoro. This pipeline has an outer diameter of 75 mm and a wall thickness of 7mm and a design pressure of 10 barg. The pipeline is buried to a nominal depth of 1 meter except at the river crossing, where it is supported off the road bridge and contained in a steel carrier pipe. The pipeline was installed using the direct laying technique, which involves the use of bulldozer and plow for excavation of a trench of 1m to protect the pipeline from mechanical damage.

  The pipeline installation costs are reported to be approximately 3.5 million Rand (corresponding to about $1 million or about $10,000/km at 3.45 Rand per $ in 1994).

  Depending on pressure, capacity of the pipeline is calculated as follows:

  - About 1,000m^3/d at a pressure drop from 7 to 6.7 barg
  - About 5000m^3/d at a pressure drop from 10 to 6 barg
  - About 7000m^3/d at a pressure drop from 10 to 0.2 barg.

  A PE pipeline was chosen because of its advantages over a steel pipe of lower diameter but higher pressure for several reasons. The first is that with PE, direct laying and easy jointing, which does not require skilled welders, are possible. Pipelaying is thus a quick operation, and costs are low. No corrosion problems are posed by PE, and therefore no wrapping or cathodic protection is required. Further advantages are the low pressure drop and the possibility of visual inspection.

- *Demand side.* The main elements on the demand side were the following:

  - Three gas-fired generators of 135 kW at Vilankulo, together with transformers to feed into a limited electric power transmission system
  - Installation of a gas-fired generator set at the UN ONUMOZ camp (which was decommissioned and mothballed after the camp was demobilized)
  - Installation of a small amount of gas distribution piping at Vilankulo for domestic use (cooking and water heating).

The Electrification of Vilankulo and Inhassoro

B.5 The construction of electricity distribution network and installation of gas-fired generators was completed in April 1998 at a total cost of US$1.6 million. Service connections were initially made to about 200 consumers in Vilankulo and 40 in Inhassoro. The number of consumers increased by 56 percent, from 240 to 375 (144 industrial/commercial and 231 domestic), over the first five months of operation. During this period, the number of consumers in Inhassoro doubled. Electricity demand has been strong, approaching a monthly average of 160 MWh. The growth in demand exceeded the load forecast by 50 percent, with a monthly average growth rate of more than 10 percent. A ready-board was introduced for the first time in the country. Monthly domestic electricity consumption is now

more than 28,000 kWh. The average monthly consumption per household is about 137 kWh in Vilankulo and 145 kWh in Inhassoro, which translates to a monthly bill of about US$17. Although the primary domestic electricity use is for lighting, many households own radio/hi-fi systems and television sets.

B.6 The operation has been superb. The technical losses are estimated at less than 13 percent, and streetlights accounted for about 5 percent of electricity generated. The penetration rate is estimated at 7.5 percent. Connections cannot be increased in Vilankulo because of the insufficient generation capacity. The peak load has already reached capacity, and the government intends to replace one generator with a bigger set from the revenues from the operation. The current management contract does not require any private investments except for new connections and routine maintenance.

The First Project to Utilize the Country's Natural Gas on a Commercial Basis

B.7 A management contract for three years was adopted mainly to reduce risks for the private sector. Introduction of a concession arrangement for the two systems that required the concessionaire to make some investments was initially considered. However, it was believed that the timing was premature and that the perceived country and project risks were too high to mobilize private capital to invest in a rural electrification project. The major deterrent to increased private sector participation was the high risk of investing in Mozambique. The key was how to reduce the risk to the acceptable level for the potential private participants and to ensure a sufficient number of bidders. Therefore, the government was inclined to adopt the management contract to operate the system for three years, as an interim arrangement, which does not confer any ownership rights or obligation on the holder of the contract to invest in the fixed assets. Under the management contract, the ownership of the asset remains with the government, and the concessionaire will be responsible for operation and management of the systems and for collection of revenues on behalf of the grantor. The concessionaire is to be paid a management fee with bonuses and penalties related to specific performance criteria.

B.8 The government received several proposals from various companies, including foreign concerns, to respond the tender. A tender commission was formed to evaluate the proposals, and a joint venture company with foreign and local interests was awarded the contract. The company was expected to take over the operation responsibility as of November 1, 1999.

B.9 The government wanted the project to be financially viable. It introduced cost-recovery tariffs for this pilot isolated electrification. The average electricity tariff to consumers is estimated at US¢12.6/kWh, which would generate revenues adequate to cover all costs including the management fee, depreciation, and a return to the government of about 8 percent on its capital investment (the current national tariff averages US¢7.5/kWh).

B.10 No subsidies are given to consumers on electricity consumption, except for a small number of consumers who pay lifeline tariffs. The capital cost was borne by the government, and the ownership of the equipment remains with the government at least for the three years of the management contract. Households and other consumers have to pay the investment costs for internal wiring and connection fees (if beyond a 30 m threshold distance) through the monthly fixed charges. No commercial loans or credits are available for house wiring or grid connection. No credit or hire purchase schemes are available to purchase electrical appliances. If such financial assistance could be arranged, a substantially higher consumption and penetration rate would be expected. The billing/collection has been beyond expectation, exceeding 98 percent.

B.11 Electrification has clearly promoted economic activities and improved social welfare in the towns. More small street vendors are now seen operating at night under the streetlights or a light bulb on an extended cord. Almost all the diesel generator users switched to the grid connection. A number of small businesses, such as workshops and mills, have started up or expanded operations. Schools now provide a better learning environment. Clinics operate longer hours and provide safer services on the reliable electricity supply. Streetlights have extended the economic and social life of the towns.

Key Lessons Learned

B.12 Among the key lessons learned are the following. First, small-scale gas schemes can be economically viable based on the demand generated by a small town such as Vilankulo, even for distances of 100 km. Second, polyethylene pipelines seem to be a means to arrange for the supply of small gas volumes in a swift and inexpensive way. Third, consumers are willing to accept higher electricity tariffs than the national average for the improved electricity services. Fourth, the availability of an electricity supply is quick to attract more local investments, especially in small industries and shops, and to improve living conditions.

C

NAIROBI SEMINAR
Program and Participants

Monday, June 23, 1997

INTRODUCTORY SESSION

08.30 Registration

09.00 Welcoming Address
(From the authorities in the host country)

09.20 Opening Addresses

GAS IN A GLOBAL CONTEXT

09.45 The role of gas in the global energy picture
Speaker: Petter Nore, Saga

10.30 Coffee / tea

11.00 Gas potential in Africa
Speaker: Eric Daffern, the World Bank

12.00 Africa gas market characteristics
- Anchor customers

Speaker: Representative from Shell or Enron

13.00 Lunch

COMMERCIAL AND LEGAL ASPECTS

14.00 The role of the government
- Upstream legal and institutional framework — Concession System
- Permits and Approvals

- Safety and Environment

Speaker: Oystein Kristiansen, NPD

15.30 Coffee/tea

16.00 Establishing a gas chain
- Characteristics of gas
- The oil chain vs. the gas chain
- Three models for organization of the chain

Speaker: Otto Granli, Statoil

17.00 Organization of the commercial chain
- The contractual chain
  - The gas sales / purchase contract
  - The transportation system
  - The transportation contract
- Political risk

Speaker: Representative from Shell

18.00 Close

Evening work:
- The gas chain — What are the strong/weak links in Africa?

Moderator: Petter Nore, Saga

Tuesday, June 24, 1997

09.00 Presentation of the last evening's work
Moderator: Petter Nore, Saga

THE USE OF GAS

09.30 The use of gas in the industry
Speaker: Kjell Roland, ECON

11.00 Coffee/tea

11.30 The Pande gas development in Mozambique
Speakers: Representatives from Mozambique and Enron

12.15 The Kudu gas development project
Speakers: Representatives from Namibia and Shell

13.00 Lunch

14.00 Natural gas and associated gas in Angola
Speaker: Representative from Angola

14.45 Group work (including coffee/tea)

- Characteristics of the Pande type project
  - What makes it viable?
  - What are the critical elements?
- Characteristics of the Kudu type project.
  - What makes it viable?
  - What are the critical elements?

17.00 Presentation of the group work

18.0 Close

EVENING PRESENTATION

21.00 Presentation of a World Bank Study on innovative uses of gas
Speaker: Gjert Laading, Aker Maritime

Wednesday, June 25, 1997

ENERGY USE OF GAS

09.00 Households and commercial users, transport sector
Speaker: Kjell Roland, ECON

09.30 The use of gas in power plants
Speaker: Auke Lont, Naturkraft

11.30 Coffee/tea

12.00 The use of gas in power plants cont'd
Speaker: Auke Lont, Naturkraft

12.30 Small power plants
Speaker: Petter Nore, Saga

13.00 Lunch

14.00 The Songo Songo gas development project
Speaker: Representative from Tanzania

14.45 Development of a gas project - Vietnam
Speaker: Otto Granli, Statoil

15.15 Group Work (including coffee/tea)
- Developing a gas power project — The case of Vietnam
- Developing a gas power project — The case of Songo Songo

17.00 Discussion and presentation of group work

18.00 Close

Thursday, June 26, 1997

09.00 Environment
- Analysis and review of environmental impacts of gas used in various end use markets. Comparing environmental impacts of gas and competing fuels
- Regulatory issues and policy instruments.

Speaker: Kjell Roland, ECON

INVESTMENT AND PROMOTION

09.45 Expectations of the oil and gas companies
Speaker: Einar Bandlien, Fountain Oil

10.30 Coffee/tea

11.00 National actions to promote
- National gas policy
  - Regulatory framework
  - Investment incentives
  - Gas project promotion

Speaker: Einar Bandlien, Fountain Oil

12.15 Financing of gas projects
- Equity/debt ratios: financing large up-front infrastructures
- Contractual agreements needed to support the financing arrangements
- Long-term commitment and guarantees and sharing of project risks
- Limited recourse financing, insurance and possibly required internal and external guarantees
- Role of different financial institutions

Speaker: Petter Nore, Saga

13.00 Lunch

14.00 Conclusions of the seminar
Group work (including coffee/tea)
Moderator: Einar Bandlien, Fountain Oil

15.30 Conclusions and recommendations
Presentation of group work Panel discussions
Moderator: Einar Bandlien, Fountain Oil

17.00 Closing of the seminar

List of Participants

Mr. Antonio dos Santos Domingos
Head of Economics and Financial Analysis
Department of Direction of Negotiations, SONAGOL
Caixa Postal 1316
Ave. 1 Congesso AO MPLA 8-16
1316 - Luanda
Republica de Angola
Tel.: 244 2 332846/339509/392751
Fax: 244 2 394128/391782

Mr. Zacarias Mavungo
Head of Petroleum and Coal Department, SADC Energy Sector - TAU
P.O. 2876, Rua Gil Vicente No. 2
Luanda
Republica de Angola
Tel: 244 2 345288
Fax: 244 2 343003

Mr. Richard Seine-Abomo
Sub-Director in Charge of Promotion and Valorization of the Mining Domain
Societe Nationale des Hydrocarbures -SNH
BP 955
Yaounde
Republic of Cameroon
Tel: 237 209862
Fax: 237 204651

Mrs. Kouma Karidia
Deputy General Manager, Petroci
Zone Industrielle de Vridi
BPV 194 Abidjan
Côte d'Ivoire
Tel: 22 5 27 19 92
Fax: 22 5 27 58 14

Mr. Koua Jean-Bruce Rockfellers
Engineer, Project Distribution de Gaz Naturel aux Industries Petroci
BPV 194 Abidjan 01
14 Bd Coude Abidjan Plateau
Côte d'Ivoire
Tel: 22 5 27 19 92
Fax: 22 5 27 58 14/21 68 24

H.E. Shemsudin Ahmed
Vice-Minister
Ministry of Mines and Energy
P.O. Box 486, Addis Ababa
Ethiopia
Tel: 251 1 512 674
Fax: 251 1 515 788

Mr. Jihad Abakoyas
General Manager
Calub Gas Share Company
P.O. Box 402, Addis Ababa
Ethiopia
Tel: 251 1 51 88 11
Fax: 251 1 51 87 42
Email: calubgas@telecom.net.et

Mr. Abiy Hunegnaw
Head of Petroleum Operations Dept. Ministry of Mines and Energy
P.0. Box 486, Addis Ababa
Ethiopia
Tel: 251 1 61 45 23
Fax: 251 1 61 45 74/515788

Mr. Joe Klemesu
Advisor, Hydrocarbon Pro. Dev.
Ministry of Mines & Energy
P.O. Box T40, Accra
Ghana
Tel: 233 21 66 80 48
Fax: 233 21 66 82 62
Email: energyl@ncs.com.gh

Mr. Timothy Kwarne Oklu
Principal Marketing Officer
Ghana National Petroleum Corporation
Private Mailbag Tema,
Ghana
Tel: 233 21 71 29 30/22 46 54
Fax: 233 21 71 29 16/23 20 39
Email: gnpc@ncs.com.gh

Mr. Wilson Cheum
Petroleum Geochemist, National Oil Corporation of Kenya
P.O. Box 58567
Nairobi
Kenya
Tel: 254-2-340030/1-8
Fax: 254-2- 340039

Mr. Victor M. R. Julien
Project Manager
ENH-Empresa Nacional de Hidrocarbonetos de Mocambique
Av. Fernao de Magalhaes No. 54
P.O. Box 4787, Maputo
Republica de Mozambique
Tel: 258 1 43 04 82
Fax: 258 1 42 48 08
Email: pvictor@zebra.uem.mz

Mr. Carlos J. Zacarias
Petroleum Geologist
National Direct, for Coal & Hydrocarbons (DNCH)
Av. Sainora Machet 285, 5o Andar Flat 10
Maputo
Republica de Mozambique
Tel: 258-1 42 09 35
Fax: 258-1 43 08 50

Mr. Mburumba Appolus
Chief Energy Economist
Ministry of Mines and Energy
Private Bag 13297
Windhoek
Namibia
Tel: 264-61-28 48 223
Fax: 264-61-23 86 43

Mr. Martin Heita
Petroleum Inspector
Ministry of Mines and Energy
Private Bag 13297
Windhoek
Namibia
Tel.: 264-61-28 48 111
Fax: 264-61-23 86 43

Mr. Pierre Hameh
Technical Department Manager
Petrosen Societe des Petroles du Senegal
B. P. 2076
Dakar
Senegal
Tel: 221-32 18 98
Fax: 221-32 18 99

Mr. David Mahuma
Senior Energy Officer
Electrical Energy and Gas
Dept. of Mineral and Energy
Private Bag 59
Pretoria 0001,
Republic of South Africa
Tel: 27-12-317 9207
Fax: 27-12-322 5224
Email: david@mepta.pwv.gov.za

Dr. Kisten Rajoo M.P.
Deputy Chairman of Comm.
National Parliament
Cape Town
Republic of South Africa
Tel: 27-31-2668270
Fax: 27-31 863008

Mr. Salvator J. Ntomola
Petroleum Geologist
P.O. Box 71447
Dar-es-Salaam,
Tanzania
Tel: 255 51 76 15 13
Fax: 255 51 76 15 14

Mr. Yete S. Mwaiyego
Director of Exploration, Production & Technical Services
Tanzania Petrol Development Corp. (TPDC)
P.O. Box 5233
Dar-es-Salaam
Tanzania
Tel: 255-51-26452
Fax: 255-51-29663

Mr. Charles S. Omujuni
Executive Engineer (II)
Energy Department
Ministry of Energy and Minerals
P.O. Box 2000
Dar-es-Salaam,
Tanzania
Tel: 255-811-324338
Fax: 255-51-116719

Speakers and Organizers

Mr. Einar Bandlien
Executive Vice President
Fountain Oil Incorporated
Solvangvn 30
1370 Asker
Norway
Tel: 47-66 79 07 17
Fax. 47-66 79 04 66
Email: ehb@fountain.no

Mr. Eric Daffern
Group Leader, Oil and Gas Division
Industry and Energy Department
1818 H Street N.W.
Washington, DC 20433
U.S.A.
Tel: 1-202-473 4057
Fax: 1-202-522 0395

Mr. Otto Granli
President
Statoil Deutschland GmbH
Wallstrasse 17-22
10179 Berlin
Germany
Tel: 30 30 86 43 00
Fax: 30 27 96 10 3

Mr. Tore Horvei
Chief Executive
SAD-ELEC - Southern African Development through Electricity
P.O. Box 1049
Rivonia
Republic of South Africa
Tel: 27 11 803 1314
Fax: 27 11 803 7019

Mr. Oystein Kristiansen
Project Director
Norwegian Petroleum Directorate
P.O. Box 600
4001 Stavanger
Norway
Tel: 47-51 87 60 00
Fax: 47-51 55 15 71

Mr. Gjert Laading
Principal Engineer, Business Development
Aker Maritime
Aker Engineering AS, Tjuvholmen
N-0250 Oslo
Norway
Tel: 47-22 94 50 00
Fax: 47-22 94 53 57
Email: gjert.laading@ae.akermar.telemax.no

Mr. Auke Lont
Managing Director
Naturkraft AS
P.O. Box 358
1324 Lysaker
Norway
Tel: 47-67 10 37 00
Fax: 47-67 58 35 78

Prof. Mark J. Mwandosya
Managing Director
The Centre for Energy, Environment, Science and Technology (CEEST)
P.O. Box 5511
Dar es Salaam
Tanzania
Tel: 255-51-66 75 69
Fax: 255-51-66 60 79
Email: ceest@www.intafrica.com

Mr. Petter Nore
Vice President
External Affairs Department
Saga Petroleum ASA
P.O. Box 490
1301 Sandvika
Norway
Tel: 47-67 12 65 06
Fax: 47-67 12 66 66

Mrs. Ragnhild Oxfjell
Senior Executive Officer
PETRAD
c/o Norwegian Petroleum Directorate
P.O. Box 600
4001 Stavanger
Norway
Tel: 47-51 87 65 39
Fax: 47-51 87 64 28
Email: ragnhild.oxfjell@petrad.no

Mr. William Porter
World Bank
1818 H Street NW
Washington DC 20433
USA
Tel: 1-202 473 - 6978
Fax: 1-202 522 – 0395

Mr. Kjell Roland
Managing Director
ECON- Centre for Economic Analysis
P.O. Box 6823
N-0130 Oslo
Norway
Tel: 47-22 98 98-50
Fax: 47-22 11 00 80
Email: kjell.roland@econ.no

Mr. Rune Schwebs
Manager Organization and Development
PETRAD
C/o Norwegian Petroleum Directorate
P.O. Box 600
4001 Stavanger
Norway
Tel: 47-51 87 6211
Fax: 47-51 87 6428
Email: rune.schwebs@petrad.no

D

Presenters, Titles, and Key Words of the Papers at the Conference

1. Petter Nore: The Role of Gas in the Global Energy Picture

Part I: The situation today
- Role of gas in primary energy consumption worldwide, in Sub Saharan Africa
- Development of gas reserves and consumption
  - Role of gas for power production/ IPPs
  - International trade
  - Gas Flaring
  - Pricing international

Part II: Challenges for the international gas industry
- Which actors
- State vs. private industry

Part III: Possible future development for gas
- Energy efficiency as function of development
- International trends

2. Eric Daffern: Gas Potential in Africa

1. Recent trends in worldwide oil and gas industry
   - Willingness of private investors
   - Environmental issues
   - Development costs falling, new technology
2. Reserve potential of Africa
   - Proven reserves have grown
3. Gas production in Africa small
4. African gas projects take a long time
5. Best use for power, industry if pipeline close by, commercial and households usually unattractive
6. Large impediments to gas in Africa: Low exploration, no rules demand small, conflicts between neighboring countries, political risks high, repatriation, payment record
7. The way forward/the role of the World Bank

3. Oystein Kristiansen: The Role of Government

Focus on upstream policy
National control issues
National participation issues
Incentive systems
Upstream legal and institutional framework
Political, administrative and commercial role
Jurisdiction
International conventions
Bilateral treaties
Regulatory options: Law, regulations, Petroleum contracts, Guidelines, International standards
Resource assessment, promotion and licensing
Safety and environment
Petroleum data management

4. Otto Granli: Establishing a Gas Chain

Along the ESMAP paper on long term gas contracts

5. Otto Granli: Organization of the Commercial Gas Chain

Contracts = ESMAP paper on long term gas contracts
The owners agreement
Pipeline company
Tariff concepts
Transportation agreement

6. Kjell Roland: Use of Gas in the Industry

Supply and demand for western countries
Pricing approaches
Use in power, LNG, etc.
Costs of coal fired power plant vs. CCGT
Affordable price in gas for export schemes
Main conclusion: Too-small demand

7. Gjert Laading: Innovative Uses of Natural Gas
   ESMAP-Paper on commercialization of marginal gas fields
8. Auke Lont: The Use of Gas in Power Plants
   Comparison for key figures between the world and Africa
   Economics of power production
   Data of gas fired power station
   Organization of a power plant project: main relations, main agreements

9. Kjell Roland: Households and Commercial Users: Transport Sector

Netback for Western countries

Gas in vehicles only in fleets

10. Petter Nore: Financing of Gas Projects

Reference to Hossein Razavi: Financing Energy Prospects in Emerging Economies
Typical financing in the pre-1970 world, in the 1970s, 1980s, and 1990s.
Basic concepts recourse/nonrecourse/limited recourse financing
Sources of equity/sources of debt
Commercial risks and instruments for mitigation
Political risks and mitigation
Structuring the financial package

11. Petter Nore: Small Power Plants

Small scale gas projects
Costs of power generation for small volumes
Cost of pipeline transport for small volumes
Influence of labor costs

12. Otto Granli: Development of a Gas Project – Vietnam

Potential of Nam Con Son Basin
Market for gas: Power
How to make it happen

13. Kjell Roland: Environment – A Major Driver for the Gas Industry

Policy instruments
Environmental advantages of gas
Energy taxes

14. Einar Bandlien: Expectations of the Oil and Gas Companies

- National policy by host governments defined by: benefit to state and people, improve balance of payment, maintain national control, environmentally friendly development, improve national expertise.
- The oil companies offer: financing and risk capital, technical and market expertise, capacity.
- The oil companies wish to receive: prospective acreage, feasible projects, competitive return on investment, incentives for low energy prices and marginal fields, share in upside of larger discoveries, protection of investment.
- To attract international oil companies the following therefore is important: geological attractive area, legal and fiscal incentives, contract models, infrastructure, market, political risk.
- For gas developments, *market* is the critical issue: does a market for the gas exist, along with anchor customers, price regulation, payment security, government participation, and finance.

15. Einar Bandlien: National Actions to Promote Investment

- Host country must compete with other countries.
- Preparation of data
- Systematic resource assessment as a basis for the economic merits of possible discoveries and an exploration strategy. Define a licensing strategy.
- Prepare the energy policy and the institutional and administrative framework.

- Document solutions for commercial use of gas.
- Prepare and run a promotion campaign.
- Define license application procedures.
- Build up the relevant institutions. Regional cooperation to attract investment.

16. Tore Horvei: Presentation of SADC Study, South Africa

See summary in Annex A.

17. Victor Julien: The Pande Gas Development in Mozambique

See summary in Annex A.

18. Martin Heida/Mburumba Appolus: Namibia's Kudu Gas Field

See summary in Annex A.

19. Y.S. Mwalyego: Songo Songo Gas to Electricity Project

See summary in Annex A.

Joint UNDP/World Bank

ENERGY SECTOR MANAGEMENT ASSISTANCE PROGRAMME (ESMAP)

LIST OF REPORTS ON COMPLETED ACTIVITIES

Region/Country	*Activity/Report Title*	*Date*	*Number*
	SUB-SAHARAN AFRICA (AFR)		
Africa Regional	Anglophone Africa Household Energy Workshop (English)	07/88	085/88
	Regional Power Seminar on Reducing Electric Power System Losses in Africa (English)	08/88	087/88
	Institutional Evaluation of EGL (English)	02/89	098/89
	Biomass Mapping Regional Workshops (English)	05/89	--
	Francophone Household Energy Workshop (French)	08/89	--
	Interafrican Electrical Engineering College: Proposals for Short- and Long-Term Development (English)	03/90	112/90
	Biomass Assessment and Mapping (English)	03/90	--
	Symposium on Power Sector Reform and Efficiency Improvement in Sub-Saharan Africa (English)	06/96	182/96
	Commercialization of Marginal Gas Fields (English)	12/97	201/97
	Commercilizing Natural Gas: Lessons from the Seminar in Nairobi for Sub-Saharan Africa and Beyond	01/00	225/00
Angola	Energy Assessment (English and Portuguese)	05/89	4708-ANG
	Power Rehabilitation and Technical Assistance (English)	10/91	142/91
Benin	Energy Assessment (English and French)	06/85	5222-BEN
Botswana	Energy Assessment (English)	09/84	4998-BT
	Pump Electrification Prefeasibility Study (English)	01/86	047/86
	Review of Electricity Service Connection Policy (English)	07/87	071/87
	Tuli Block Farms Electrification Study (English)	07/87	072/87
	Household Energy Issues Study (English)	02/88	--
	Urban Household Energy Strategy Study (English)	05/91	132/91
Burkina Faso	Energy Assessment (English and French)	01/86	5730-BUR
	Technical Assistance Program (English)	03/86	052/86
	Urban Household Energy Strategy Study (English and French)	06/91	134/91
Burundi	Energy Assessment (English)	06/82	3778-BU
	Petroleum Supply Management (English)	01/84	012/84
	Status Report (English and French)	02/84	011/84
	Presentation of Energy Projects for the Fourth Five-Year Plan (1983-1987) (English and French)	05/85	036/85
	Improved Charcoal Cookstove Strategy (English and French)	09/85	042/85
	Peat Utilization Project (English)	11/85	046/85
	Energy Assessment (English and French)	01/92	9215-BU
Cape Verde	Energy Assessment (English and Portuguese)	08/84	5073-CV
	Household Energy Strategy Study (English)	02/90	110/90
Central African Republic	Energy Assessement (French)	08/92	9898-CAR
Chad	Elements of Strategy for Urban Household Energy The Case of N'djamena (French)	12/93	160/94
Comoros	Energy Assessment (English and French)	01/88	7104-COM
Congo	Energy Assessment (English)	01/88	6420-COB
	Power Development Plan (English and French)	03/90	106/90
Côte d'Ivoire	Energy Assessment (English and French)	04/85	5250-IVC
	Improved Biomass Utilization (English and French)	04/87	069/87
	Power System Efficiency Study (English)	12/87	--
	Power Sector Efficiency Study (French)	02/92	140/91

Region/Country	*Activity/Report Title*	*Date*	*Number*
Côte d'Ivoire	Project of Energy Efficiency in Buildings (English)	09/95	175/95
Ethiopia	Energy Assessment (English)	07/84	4741-ET
	Power System Efficiency Study (English)	10/85	045/85
	Agricultural Residue Briquetting Pilot Project (English)	12/86	062/86
	Bagasse Study (English)	12/86	063/86
	Cooking Efficiency Project (English)	12/87	--
	Energy Assessment (English)	02/96	179/96
Gabon	Energy Assessment (English)	07/88	6915-GA
The Gambia	Energy Assessment (English)	11/83	4743-GM
	Solar Water Heating Retrofit Project (English)	02/85	030/85
	Solar Photovoltaic Applications (English)	03/85	032/85
	Petroleum Supply Management Assistance (English)	04/85	035/85
Ghana	Energy Assessment (English)	11/86	6234-GH
	Energy Rationalization in the Industrial Sector (English)	06/88	084/88
	Sawmill Residues Utilization Study (English)	11/88	074/87
	Industrial Energy Efficiency (English)	11/92	148/92
Guinea	Energy Assessment (English)	11/86	6137-GUI
	Household Energy Strategy (English and French)	01/94	163/94
Guinea-Bissau	Energy Assessment (English and Portuguese)	08/84	5083-GUB
	Recommended Technical Assistance Projects (English & Portuguese)	04/85	033/85
	Management Options for the Electric Power and Water Supply Subsectors (English)	02/90	100/90
	Power and Water Institutional Restructuring (French)	04/91	118/91
Kenya	Energy Assessment (English)	05/82	3800-KE
	Power System Efficiency Study (English)	03/84	014/84
	Status Report (English)	05/84	016/84
	Coal Conversion Action Plan (English)	02/87	--
	Solar Water Heating Study (English)	02/87	066/87
	Peri-Urban Woodfuel Development (English)	10/87	076/87
	Power Master Plan (English)	11/87	--
	Power Loss Reduction Study (English)	09/96	186/96
Lesotho	Energy Assessment (English)	01/84	4676-LSO
Liberia	Energy Assessment (English)	12/84	5279-LBR
	Recommended Technical Assistance Projects (English)	06/85	038/85
	Power System Efficiency Study (English)	12/87	081/87
Madagascar	Energy Assessment (English)	01/87	5700-MAG
	Power System Efficiency Study (English and French)	12/87	075/87
	Environmental Impact of Woodfuels (French)	10/95	176/95
Malawi	Energy Assessment (English)	08/82	3903-MAL
	Technical Assistance to Improve the Efficiency of Fuelwood Use in the Tobacco Industry (English)	11/83	009/83
	Status Report (English)	01/84	013/84
Mali	Energy Assessment (English and French)	11/91	8423-MLI
	Household Energy Strategy (English and French)	03/92	147/92
Islamic Republic of Mauritania	Energy Assessment (English and French)	04/85	5224-MAU
	Household Energy Strategy Study (English and French)	07/90	123/90
Mauritius	Energy Assessment (English)	12/81	3510-MAS
	Status Report (English)	10/83	008/83
	Power System Efficiency Audit (English)	05/87	070/87
Mauritius	Bagasse Power Potential (English)	10/87	077/87

Region/Country	*Activity/Report Title*	*Date*	*Number*
Mauritius	Energy Sector Review (English)	12/94	3643-MAS
Mozambique	Energy Assessment (English)	01/87	6128-MOZ
	Household Electricity Utilization Study (English)	03/90	113/90
	Electricity Tariffs Study (English)	06/96	181/96
	Sample Survey of Low Voltage Electricity Customers	06/97	195/97
Namibia	Energy Assessment (English)	03/93	11320-NAM
Niger	Energy Assessment (French)	05/84	4642-NIR
	Status Report (English and French)	02/86	051/86
	Improved Stoves Project (English and French)	12/87	080/87
	Household Energy Conservation and Substitution (English and French)	01/88	082/88
Nigeria	Energy Assessment (English)	08/83	4440-UNI
	Energy Assessment (English)	07/93	11672-UNI
Rwanda	Energy Assessment (English)	06/82	3779-RW
	Status Report (English and French)	05/84	017/84
	Improved Charcoal Cookstove Strategy (English and French)	08/86	059/86
	Improved Charcoal Production Techniques (English and French)	02/87	065/87
	Energy Assessment (English and French)	07/91	8017-RW
	Commercialization of Improved Charcoal Stoves and Carbonization Techniques Mid-Term Progress Report (English and French)	12/91	141/91
SADC	SADC Regional Power Interconnection Study, Vols. I-IV (English)	12/93	--
SADCC	SADCC Regional Sector: Regional Capacity-Building Program for Energy Surveys and Policy Analysis (English)	11/91	--
Sao Tome and Principe	Energy Assessment (English)	10/85	5803-STP
Senegal	Energy Assessment (English)	07/83	4182-SE
	Status Report (English and French)	10/84	025/84
	Industrial Energy Conservation Study (English)	05/85	037/85
	Preparatory Assistance for Donor Meeting (English and French)	04/86	056/86
	Urban Household Energy Strategy (English)	02/89	096/89
	Industrial Energy Conservation Program (English)	05/94	165/94
Seychelles	Energy Assessment (English)	01/84	4693-SEY
	Electric Power System Efficiency Study (English)	08/84	021/84
Sierra Leone	Energy Assessment (English)	10/87	6597-SL
Somalia	Energy Assessment (English)	12/85	5796-SO
South Africa Republic of	Options for the Structure and Regulation of Natural Gas Industry (English)	05/95	172/95
Sudan	Management Assistance to the Ministry of Energy and Mining	05/83	003/83
	Energy Assessment (English)	07/83	4511-SU
	Power System Efficiency Study (English)	06/84	018/84
	Status Report (English)	11/84	026/84
	Wood Energy/Forestry Feasibility (English)	07/87	073/87
Swaziland	Energy Assessment (English)	02/87	6262-SW
	Household Energy Strategy Study	10/97	198/97
Tanzania	Energy Assessment (English)	11/84	4969-TA
	Peri-Urban Woodfuels Feasibility Study (English)	08/88	086/88
	Tobacco Curing Efficiency Study (English)	05/89	102/89
	Remote Sensing and Mapping of Woodlands (English)	06/90	--
	Industrial Energy Efficiency Technical Assistance (English)	08/90	122/90
Tanzania	Power Loss Reduction Volume 1: Transmission and Distribution SystemTechnical Loss Reduction and Network Development (English)	06/98	204A/98

Region/Country	*Activity/Report Title*	*Date*	*Number*
Tanzania	Power Loss Reduction Volume 2: Reduction of Non-Technical Losses (English)	06/98	204B/98
Togo	Energy Assessment (English)	06/85	5221-TO
	Wood Recovery in the Nangbeto Lake (English and French)	04/86	055/86
	Power Efficiency Improvement (English and French)	12/87	078/87
Uganda	Energy Assessment (English)	07/83	4453-UG
	Status Report (English)	08/84	020/84
	Institutional Review of the Energy Sector (English)	01/85	029/85
	Energy Efficiency in Tobacco Curing Industry (English)	02/86	049/86
	Fuelwood/Forestry Feasibility Study (English)	03/86	053/86
	Power System Efficiency Study (English)	12/88	092/88
	Energy Efficiency Improvement in the Brick and Tile Industry (English)	02/89	097/89
	Tobacco Curing Pilot Project (English)	03/89	UNDP Terminal Report
	Energy Assessment (English)	12/96	193/96
	Rural Electrification Strategy Study	09/99	221/99
Zaire	Energy Assessment (English)	05/86	5837-ZR
Zambia	Energy Assessment (English)	01/83	4110-ZA
	Status Report (English)	08/85	039/85
	Energy Sector Institutional Review (English)	11/86	060/86
	Power Subsector Efficiency Study (English)	02/89	093/88
	Energy Strategy Study (English)	02/89	094/88
	Urban Household Energy Strategy Study (English)	08/90	121/90
Zimbabwe	Energy Assessment (English)	06/82	3765-ZIM
	Power System Efficiency Study (English)	06/83	005/83
	Status Report (English)	08/84	019/84
	Power Sector Management Assistance Project (English)	04/85	034/85
	Power Sector Management Institution Building (English)	09/89	--
	Petroleum Management Assistance (English)	12/89	109/89
	Charcoal Utilization Prefeasibility Study (English)	06/90	119/90
	Integrated Energy Strategy Evaluation (English)	01/92	8768-ZIM
	Energy Efficiency Technical Assistance Project: Strategic Framework for a National Energy Efficiency Improvement Program (English)	04/94	--
	Capacity Building for the National Energy Efficiency Improvement Programme (NEEIP) (English)	12/94	--
	EAST ASIA AND PACIFIC (EAP)		
Asia Regional	Pacific Household and Rural Energy Seminar (English)	11/90	--
China	County-Level Rural Energy Assessments (English)	05/89	101/89
	Fuelwood Forestry Preinvestment Study (English)	12/89	105/89
	Strategic Options for Power Sector Reform in China (English)	07/93	156/93
	Energy Efficiency and Pollution Control in Township and Village Enterprises (TVE) Industry (English)	11/94	168/94
	Energy for Rural Development in China: An Assessment Based on a Joint Chinese/ESMAP Study in Six Counties (English)	06/96	183/96
	Improving the Technical Efficiency of Decentralized Power Companies	09/99	222/999
Fiji	Energy Assessment (English)	06/83	4462-FIJ

Region/Country	*Activity/Report Title*	*Date*	*Number*
Indonesia	Energy Assessment (English)	11/81	3543-IND
	Status Report (English)	09/84	022/84
	Power Generation Efficiency Study (English)	02/86	050/86
	Energy Efficiency in the Brick, Tile and Lime Industries (English)	04/87	067/87
	Diesel Generating Plant Efficiency Study (English)	12/88	095/88
	Urban Household Energy Strategy Study (English)	02/90	107/90
	Biomass Gasifier Preinvestment Study Vols. I & II (English)	12/90	124/90
	Prospects for Biomass Power Generation with Emphasis on Palm Oil, Sugar, Rubberwood and Plywood Residues (English)	11/94	167/94
Lao PDR	Urban Electricity Demand Assessment Study (English)	03/93	154/93
	Institutional Development for Off-Grid Electrification	06/99	215/99
Malaysia	Sabah Power System Efficiency Study (English)	03/87	068/87
	Gas Utilization Study (English)	09/91	9645-MA
Myanmar	Energy Assessment (English)	06/85	5416-BA
Papua New Guinea	Energy Assessment (English)	06/82	3882-PNG
	Status Report (English)	07/83	006/83
	Energy Strategy Paper (English)	--	--
	Institutional Review in the Energy Sector (English)	10/84	023/84
	Power Tariff Study (English)	10/84	024/84
Philippines	Commercial Potential for Power Production from Agricultural Residues (English)	12/93	157/93
	Energy Conservation Study (English)	08/94	--
Solomon Islands	Energy Assessment (English)	06/83	4404-SOL
	Energy Assessment (English)	01/92	979-SOL
South Pacific	Petroleum Transport in the South Pacific (English)	05/86	--
Thailand	Energy Assessment (English)	09/85	5793-TH
	Rural Energy Issues and Options (English)	09/85	044/85
	Accelerated Dissemination of Improved Stoves and Charcoal Kilns (English)	09/87	079/87
	Northeast Region Village Forestry and Woodfuels Preinvestment Study (English)	02/88	083/88
	Impact of Lower Oil Prices (English)	08/88	--
	Coal Development and Utilization Study (English)	10/89	--
Tonga	Energy Assessment (English)	06/85	5498-TON
Vanuatu	Energy Assessment (English)	06/85	5577-VA
Vietnam	Rural and Household Energy-Issues and Options (English)	01/94	161/94
	Power Sector Reform and Restructuring in Vietnam: Final Report to the Steering Committee (English and Vietnamese)	09/95	174/95
	Household Energy Technical Assistance: Improved Coal Briquetting and Commercialized Dissemination of Higher Efficiency Biomass and Coal Stoves (English)	01/96	178/96
Western Samoa	Energy Assessment (English)	06/85	5497-WSO
	SOUTH ASIA (SAS)		
Bangladesh	Energy Assessment (English)	10/82	3873-BD
	Priority Investment Program (English)	05/83	002/83
	Status Report (English)	04/84	015/84
	Power System Efficiency Study (English)	02/85	031/85

Region/Country	*Activity/Report Title*	*Date*	*Number*
Bangladesh	Small Scale Uses of Gas Prefeasibility Study (English)	12/88	--
India	Opportunities for Commercialization of Nonconventional Energy Systems (English)	11/88	091/88
	Maharashtra Bagasse Energy Efficiency Project (English)	07/90	120/90
	Mini-Hydro Development on Irrigation Dams and Canal Drops Vols. I, II and III (English)	07/91	139/91
	WindFarm Pre-Investment Study (English)	12/92	150/92
	Power Sector Reform Seminar (English)	04/94	166/94
	Environmental Issues in the Power Sector (English)	06/98	205/98
	Environmental Issues in the Power Sector: Manual for Environmental Decision Making (English)	06/99	213/99
	Household Energy Strategies for Urban India: The Case of Hyderabad	06/99	214/99
Nepal	Energy Assessment (English)	08/83	4474-NEP
	Status Report (English)	01/85	028/84
	Energy Efficiency & Fuel Substitution in Industries (English)	06/93	158/93
Pakistan	Household Energy Assessment (English)	05/88	--
	Assessment of Photovoltaic Programs, Applications, and Markets (English)	10/89	103/89
	National Household Energy Survey and Strategy Formulation Study: Project Terminal Report (English)	03/94	--
	Managing the Energy Transition (English)	10/94	--
	Lighting Efficiency Improvement Program Phase 1: Commercial Buildings Five Year Plan (English)	10/94	--
Sri Lanka	Energy Assessment (English)	05/82	3792-CE
	Power System Loss Reduction Study (English)	07/83	007/83
	Status Report (English)	01/84	010/84
	Industrial Energy Conservation Study (English)	03/86	054/86

EUROPE AND CENTRAL ASIA (ECA)

Bulgaria	Natural Gas Policies and Issues (English)	10/96	188/96
Central and Eastern Europe	Power Sector Reform in Selected Countries	07/97	196/97
Eastern Europe	The Future of Natural Gas in Eastern Europe (English)	08/92	149/92
Kazakhstan	Natural Gas Investment Study, Volumes 1, 2 & 3	12/97	199/97
Kazakhstan & Kyrgyzstan	Opportunities for Renewable Energy Development	11/97	16855-KAZ
Poland	Energy Sector Restructuring Program Vols. I-V (English)	01/93	153/93
	Natural Gas Upstream Policy (English and Polish)	08/98	206/98
	Energy Sector Restructuring Program: Establishing the Energy Regulation Authority	10/98	208/98
Portugal	Energy Assessment (English)	04/84	4824-PO
Romania	Natural Gas Development Strategy (English)	12/96	192/96
Slovenia	Workshop on Private Participation in the Power Sector (English)	02/99	211/99
Turkey	Energy Assessment (English)	03/83	3877-TU

Region/Country	*Activity/Report Title*	*Date*	*Number*
	MIDDLE EAST AND NORTH AFRICA (MNA)		
Arab Republic of Egypt	Energy Assessment (English)	10/96	189/96
Arab Republic of Egypt	Energy Assessment (English and French)	03/84	4157-MOR
	Status Report (English and French)	01/86	048/86
Morocco	Energy Sector Institutional Development Study (English and French)	07/95	173/95
	Natural Gas Pricing Study (French)	10/98	209/98
	Gas Development Plan Phase II (French)	02/99	210/99
Syria	Energy Assessment (English)	05/86	5822-SYR
	Electric Power Efficiency Study (English)	09/88	089/88
	Energy Efficiency Improvement in the Cement Sector (English)	04/89	099/89
Syria	Energy Efficiency Improvement in the Fertilizer Sector (English)	06/90	115/90
Tunisia	Fuel Substitution (English and French)	03/90	--
	Power Efficiency Study (English and French)	02/92	136/91
	Energy Management Strategy in the Residential and Tertiary Sectors (English)	04/92	146/92
	Renewable Energy Strategy Study, Volume I (French)	11/96	190A/96
	Renewable Energy Strategy Study, Volume II (French)	11/96	190B/96
Yemen	Energy Assessment (English)	12/84	4892-YAR
	Energy Investment Priorities (English)	02/87	6376-YAR
	Household Energy Strategy Study Phase I (English)	03/91	126/91
	LATIN AMERICA AND THE CARIBBEAN (LAC)		
LAC Regional	Regional Seminar on Electric Power System Loss Reduction in the Caribbean (English)	07/89	--
	Elimination of Lead in Gasoline in Latin America and the Caribbean (English and Spanish)	04/97	194/97
	Elimination of Lead in Gasoline in Latin America and the Caribbean - Status Report (English and Spanish)	12/97	200/97
	Harmonization of Fuels Specifications in Latin America and the Caribbean (English and Spanish)	06/98	203/98
Bolivia	Energy Assessment (English)	04/83	4213-BO
	National Energy Plan (English)	12/87	--
	La Paz Private Power Technical Assistance (English)	11/90	111/90
	Prefeasibility Evaluation Rural Electrification and Demand Assessment (English and Spanish)	04/91	129/91
	National Energy Plan (Spanish)	08/91	131/91
	Private Power Generation and Transmission (English)	01/92	137/91
	Natural Gas Distribution: Economics and Regulation (English)	03/92	125/92
	Natural Gas Sector Policies and Issues (English and Spanish)	12/93	164/93
	Household Rural Energy Strategy (English and Spanish)	01/94	162/94
	Preparation of Capitalization of the Hydrocarbon Sector	12/96	191/96
Brazil	Energy Efficiency & Conservation: Strategic Partnership for Energy Efficiency in Brazil (English)	01/95	170/95
	Hydro and Thermal Power Sector Study	09/97	197/97
Chile	Energy Sector Review (English)	08/88	7129-CH
Colombia	Energy Strategy Paper (English)	12/86	--
	Power Sector Restructuring (English)	11/94	169/94

Region/Country	*Activity/Report Title*	*Date*	*Number*
Colombia	Energy Efficiency Report for the Commercial and Public Sector (English)	06/96	184/96
Costa Rica	Energy Assessment (English and Spanish)	01/84	4655-CR
	Recommended Technical Assistance Projects (English)	11/84	027/84
	Forest Residues Utilization Study (English and Spanish)	02/90	108/90
Dominican Republic	Energy Assessment (English)	05/91	8234-DO
Ecuador	Energy Assessment (Spanish)	12/85	5865-EC
	Energy Strategy Phase I (Spanish)	07/88	--
	Energy Strategy (English)	04/91	--
	Private Minihydropower Development Study (English)	11/92	--
	Energy Pricing Subsidies and Interfuel Substitution (English)	08/94	11798-EC
	Energy Pricing, Poverty and Social Mitigation (English)	08/94	12831-EC
Guatemala	Issues and Options in the Energy Sector (English)	09/93	12160-GU
Haiti	Energy Assessment (English and French)	06/82	3672-HA
	Status Report (English and French)	08/85	041/85
	Household Energy Strategy (English and French)	12/91	143/91
Honduras	Energy Assessment (English)	08/87	6476-HO
	Petroleum Supply Management (English)	03/91	128/91
Jamaica	Energy Assessment (English)	04/85	5466-JM
	Petroleum Procurement, Refining, and Distribution Study (English)	11/86	061/86
	Energy Efficiency Building Code Phase I (English)	03/88	--
	Energy Efficiency Standards and Labels Phase I (English)	03/88	--
	Management Information System Phase I (English)	03/88	--
	Charcoal Production Project (English)	09/88	090/88
	FIDCO Sawmill Residues Utilization Study (English)	09/88	088/88
	Energy Sector Strategy and Investment Planning Study (English)	07/92	135/92
Mexico	Improved Charcoal Production Within Forest Management for the State of Veracruz (English and Spanish)	08/91	138/91
	Energy Efficiency Management Technical Assistance to the Comision Nacional para el Ahorro de Energia (CONAE) (English)	04/96	180/96
Panama	Power System Efficiency Study (English)	06/83	004/83
Paraguay	Energy Assessment (English)	10/84	5145-PA
	Recommended Technical Assistance Projects (English)	09/85	--
	Status Report (English and Spanish)	09/85	043/85
Peru	Energy Assessment (English)	01/84	4677-PE
	Status Report (English)	08/85	040/85
	Proposal for a Stove Dissemination Program in the Sierra (English and Spanish)	02/87	064/87
	Energy Strategy (English and Spanish)	12/90	--
	Study of Energy Taxation and Liberalization of the Hydrocarbons Sector (English and Spanish)	120/93	159/93
	Reform and Privatization in the Hydrocarbon Sector (English and Spanish)	07/99	216/99
Saint Lucia	Energy Assessment (English)	09/84	5111-SLU
St. Vincent and the Grenadines	Energy Assessment (English)	09/84	5103-STV
Sub Andean	Environmental and Social Regulation of Oil and Gas Operations in Sensitive Areas of the Sub-Andean Basin (English and Spanish)	07/99	217/99

Region/Country	*Activity/Report Title*	*Date*	*Number*
Trinidad and Tobago	Energy Assessment (English)	12/85	5930-TR
	GLOBAL		
	Energy End Use Efficiency: Research and Strategy (English)	11/89	--
	Women and Energy--A Resource Guide The International Network: Policies and Experience (English)	04/90	--
	Guidelines for Utility Customer Management and Metering (English and Spanish)	07/91	--
	Assessment of Personal Computer Models for Energy Planning in Developing Countries (English)	10/91	--
	Long-Term Gas Contracts Principles and Applications (English)	02/93	152/93
	Comparative Behavior of Firms Under Public and Private Ownership (English)	05/93	155/93
	Development of Regional Electric Power Networks (English)	10/94	--
	Roundtable on Energy Efficiency (English)	02/95	171/95
	Assessing Pollution Abatement Policies with a Case Study of Ankara (English)	11/95	177/95
	A Synopsis of the Third Annual Roundtable on Independent Power Projects: Rhetoric and Reality (English)	08/96	187/96
	Rural Energy and Development Roundtable (English)	05/98	202/98
	A Synopsis of the Second Roundtable on Energy Efficiency: Institutional and Financial Delivery Mechanisms (English)	09/98	207/98
	The Effect of a Shadow Price on Carbon Emission in the Energy Portfolio of the World Bank: A Carbon Backcasting Exercise (English)	02/99	212/99
	Increasing the Efficiency of Gas Distribution Phase 1: Case Studies and Thematic Data Sheets	07/99	218/99
	Global Energy Sector Reform in Developing Countries: A Scorecard	07/99	219/99
	Global Lighting Services for the Poor Phase II: Text Marketing of Small "Solar" Batteries for Rural Electrification Purposes	08/99	220/99
	A Review of the Renewable Energy Activities of the UNDP/ World Bank Energy Sector Management Assistance Programme 1993 to 1998	11/99	223/99
	Energy, Transportation and Environment: Policy Options for Environmental Improvement	12/99	224/99

1/24/2000

ESMAP

The World Bank

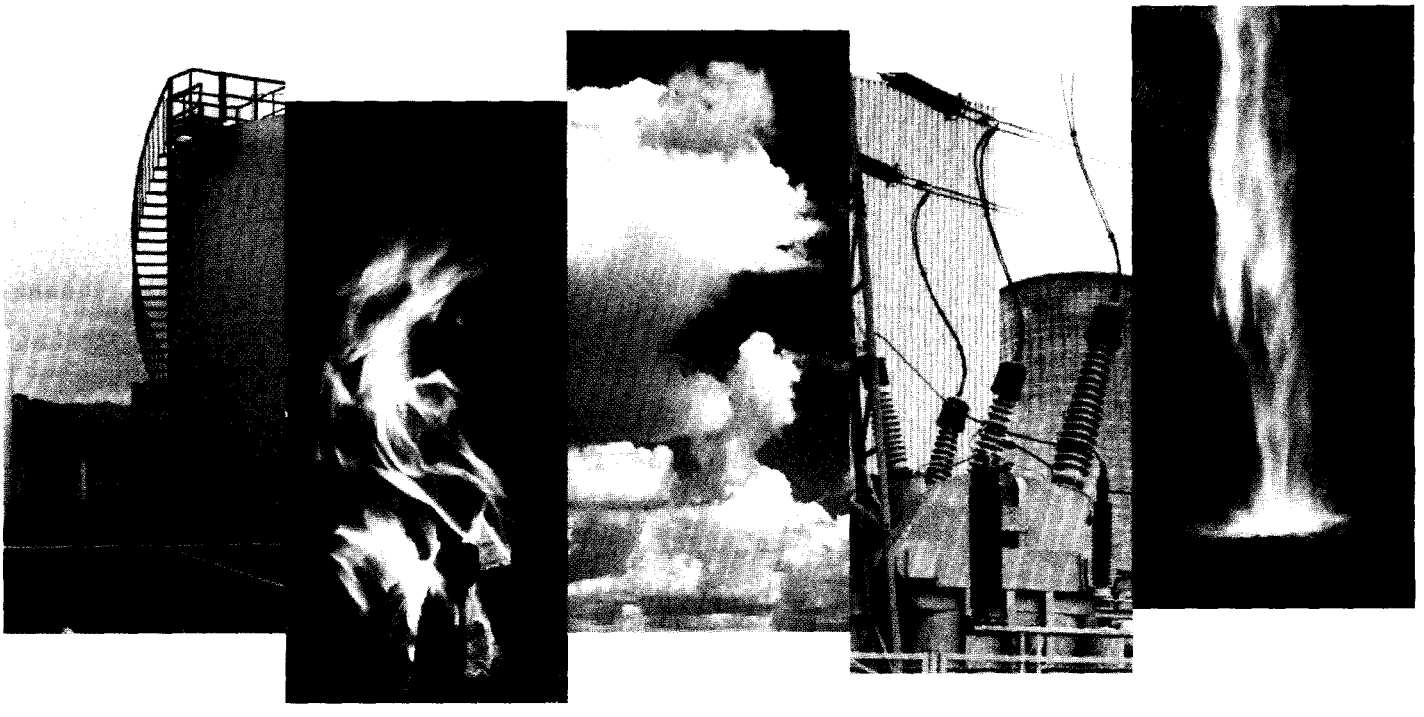
1818 H Street, NW

Washington, DC 20433 USA

Tel.: 1.202.458.2321 Fax.: 1.202.522.3018

Internet: www.worldbank.org/esmap

Email: esmap@worldbank.org



A joint UNDP/World Bank Programme