Joint United Nations Development Programme / World Bank

ESMAP

Energy Sector Management Assistance Programme

Commercialization of Marginal Gas Fields

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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:

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Abbreviations and Acronyms

AG	associated gas
AGI	Africa Gas Initiative
ATR	autothermal reformer
bbl	barrels
b/d	barrels per day
bcf	billion cubic feet
BL	battery limits
BP	British Petroleum
Btu	British thermal units
°C	degrees Celsius
capex	capital expenditures
CIF	cost, insurance, and freight (included in price)
CNG	compressed natural gas
CO	carbon monoxide
CO_2	carbon dioxide
DME	dimethyl ether
DR	direct reduction (process)
DRI	direct reduced iron (product)
EAF	electric arc furnace
ESMAP	Energy Sector Management Assistance Programme
EU	European Union
FOB	free on board (price)
F-T	Fischer-Tropsch (process)
ft^2	square feet
FPSO	floating, production, storage, and off-loading
GJ	gigajoules
GOR	gas-to-oil ratio
GRI	Gas Research Institute
GTL	gas-to-liquids
GTO	gas-to-olefins
H_2	hydrogen

HBI	hot briquetted iron
H_2S	hydrogen sulfide
kcal	kilocalories
kg	kilograms
kJ	kilojoules
km	kilometers
kWh	kilowatt-hours
LNG	liquefied natural gas
LPG	liquefied petroleum gas
m^2	square meters
M	thousand
Midrex	a direct reduction process, developed by the Midrex Corporation
MM	million
MMBtu	million British thermal units
MTBE	methyl tertiary butyl ether
MTO	methanol-to-olefins
MW	megawatts
N_2	nitrogen
ncm	normal cubic meters
NH_3	ammonia
NKr	Norwegian kroner
NO_x	oxides of nitrogen
NPV	net present value
O&M	operating and maintenance
PVC	polyvinyl chloride
PWV	Pretoria, Witwatersrand, and Vereeniging, in RSA
RSA	Republic of South Africa
SADC	Southern African Development Community
scf	standard cubic feet
scm	standard cubic meters
syncrude	synthetic crude oil
synfuels	synthetic fuels
syngas	synthesis gas, a mixture of hydrogen and carbon monoxide
t	metric tons
tcf	trillion cubic feet

TCR	Topsøe Convection Reformer
t/cd	metric tons per calendar day
t/d	metric tons per day
t/y	metric tons per year
UAP	urea ammonium phosphate
UNDP	United Nations Development Programme
$	U.S. dollars

Units of Measure

Methane has a calorific value of close to 1,000 Btu/scf.

1 gigajoule (GJ)	=	0.9484 MMBtu, or approximately 1 MMBtu
1 kcal	=	3.968 Btu, or approximately 4 Btu
1 tcf	=	1,000 bcf = 10^{12} scf ~ 10^{15} Btu ~ 10^{9} GJ
1 bcf	~	1,000,000 GJ
API gravity	=	(141.5/specific gravity 60-60°F) - 131.5

All dollar figures are given in U.S. dollars ($).

Overview

1 Natural gas reservoirs are plentiful around the world, but many of them currently seem too small, or too remote from sizable population centers, to be developed economically. Similarly, a great deal of the world's natural gas is associated with liquid hydrocarbons, and producers often maximize the extraction of these more valuable liquids even when it means losing the associated gas through flaring. Yet natural gas is among the most efficient and environmentally benign fuels available. It also represents an important resource for developing countries that are energy poor, dependent on highly polluting fuels or expensive imports, or at risk of deforestation or desertification because of excessive use of biomass. Hence, if reservoirs that are now only marginally economic producers of gas could be made commercially viable, developing countries and the world as a whole would gain a significant increment in efficient, clean energy.

2 The World Bank and the Energy Sector Management Assistance Programme (ESMAP) have already been providing assistance to client countries that are seeking to commercialize production of natural gas. Under the auspices of the Africa Gas Initiative (AGI) in particular, the Bank and ESMAP have been supporting efforts to create local and regional markets for natural gas and liquefied petroleum gas (LPG). The AGI has focused mainly on finding uses for gas—in traditional applications such as power generation—and on addressing market imperfections that inhibit investors from coming into the gas market on their own. In many areas, however, market-promoting efforts will not be enough in themselves to make marginal fields commercial. Rather, the best available and most promising emerging technologies for using and converting gas will also have to be put in place to make the fields commercial.

3 ESMAP carried out the present study specifically to address the technological aspects of commercializing marginal gas fields. Conducted with support from the Norwegian Oil and Gas Trust Fund, the study reviews and assesses the established and potential technological processes with particular attention to their suitability to take the production of small gas fields and turn it to commercially viable activity. Although the report focuses on a range of small fields in Sub-Saharan Africa, its general conclusions on the commercial viability of the technologies considered are valid worldwide.

Processes and How They Were Assessed

4 The study team reviewed the literature and visited developers and licensers of both mature and novel technologies. In addition, the team carried out detailed technical investigations of these technologies, along with market and cost assessments of different-

sized plants, which included operating and maintenance expenditures, and calculations of gas values.[1]

5 The team examined the commercial potential of several technological applications for natural gas from small fields:

- Use of gas for direct reduction (DR) of iron oxides, the product of which can then be used in steelmaking.
- Manufacture of carbon black and hydrogen from the gas. Carbon black is used predominantly in the production of vehicle tires.
- Stand-alone methanol plants. Methanol, which can be made from gas, is used in the synthesis of chemicals, particularly formaldehyde, and methyl tertiary butyl ether (MTBE), which is used as a high octane gasoline blending component.
- The novel technology of floating, production, storage, and off-loading (FPSO) methanol plants for small, offshore fields.
- The emerging process of gas-to-liquids (GTL) conversion of natural gas to synthetic fuels (synfuels).
- Conversion of natural gas to dimethyl ether (DME), potentially a clean-fuel substitute for diesel.
- Gas-to-olefins (GTO) and methanol-to-olefins (MTO). These processes involve converting natural gas to methanol, followed by converting methanol to light olefins, such as ethylene and propylene, which are used as petrochemical feedstocks.
- Stand-alone ammonia plants or a combined ammonia-urea complex. Ammonia is primarily used for production of fertilizers, and urea is a key nitrogenous fertilizer.

6 The study group estimated capital and operational costs for each technology by assuming a 3-year investment period and 25 years of operation. Because of economies of scale, all the processes reviewed here have a decreasing capital cost per unit of product produced with increasing plant size.

7 Gas values of the promising processes are shown in Table 1 (values are from the table in Annex 13 and Table 3.11, and assumptions made in the calculations are further explained in Chapter 2 under the heading General Assumptions for Each Technology).

[1] The *gas value* is the maximum gas price that can be charged at the burner tip for a given process that will permit the project to remain competitive in the market. The gas value thus includes the transportation cost, if any, to the burner tip, whereas the *netback value* is the field value, exclusive of transportation. The calculated gas values are highly sensitive to the discount rate of interest used and to the capital expenditures and price of the product in question. The values reported are therefore intended as first-order estimates only. The economic analysis was used to identify which options should be excluded from further consideration and which should be pursued through more detailed feasibility studies. Because the same methodology is followed in carrying out the calculations in each technology area, the overall ranking of the processes should not be affected markedly by the assumptions made.

Where the gas value is higher than the supply cost, the process is potentially commercially viable. Supply costs are not shown in the table, as they are specific to each gas field and may span a wide range. As a first approximation of viability, however, a process may be considered economic if the gas value exceeds \$0.50 per million British thermal units (MMBtu). If a country imposes a penalty for flaring gas, however, the supply cost of gas may even be negative.

Table 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 capital costs on the U.S. Gulf Coast must be multiplied to estimate capital costs at the gas field. Midrex, a process of the Midrex Direct Reduction Corporation, is the most commonly used direct reduction 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.

Viability of the Technologies for Small Gas Fields

8 The use of natural gas for direct reduction (DR) of iron oxides for subsequent use in the manufacture of steel gives the highest gas value for gas fields in the range upwards of 0.25 trillion cubic feet (tcf). New processes that can handle iron ore fines rather than pelletized or lumpy ores are particularly attractive economically. The final economics of this method will depend on the distance between the iron ore deposit and the gas field, the purity of the ore (iron content; the amount of metallic residuals, such as copper, nickel, and cobalt; and the amount of mineral oxides, such as silica, magnesia, alumina, and titania), the distance of the DR or steel plant from a harbor and, for steel manufacturers, the availability of low-cost electricity.

9 For very small gas fields, producing about 0.1 tcf, a novel process for manufacturing carbon black and hydrogen from natural gas gives a high gas value. The

carbon black plant needs to be located close to a hydrogen consumer, such as a refinery or a DR plant.

10 The economics of methanol plants for gas fields that produce 0.5 to 1.0 tcf are attractive. The floating production methanol plant is a novel technology that could suit offshore fields. Its advantages are discussed in Chapter 3 and Annex 4 of this report.

11 Gas-to-liquids (GTL), conversion of natural gas to synthetic fuels (synfuels), is an emerging area of technology. At present, it appears that only large synfuel plants (20,000–50,000 barrels per day, b/d), consuming 2 tcf or more of natural gas in a 25-year period, are commercially viable because of the considerable economies of scale required. The economics in such cases will be judged by their comparative advantage over liquefied natural gas (LNG). Significant development work is under way to make smaller plants (for example, those producing 5,000 b/d) economic. If and when the viability of small plants is commercially demonstrated, GTL technology may be seriously considered for marginal gas fields around the world. Such a development would represent a major breakthrough for gas utilization, and would significantly increase the total amount of economically recoverable oil and gas reserves in the world. Given the level of interest in GTL and of development work undertaken at present, it may be a short time before a breakthrough occurs. With novel synthesis gas processes, more selective catalyst systems, and reductions in capital costs, the first profitable 5,000 b/d synfuel plant could be contracted within the next few years.

12 Although the conversion of natural gas to dimethyl ether (DME) is economic on paper, as shown in Table 1, DME is not likely to emerge as a clean substitute for diesel in most developing countries for the foreseeable future. DME is a gas at ambient temperature and pressure and would require a completely new infrastructure for storage and distribution as a transportation fuel.

13 Gas-to-olefins (GTO) and methanol-to-olefins (MTO) call for enormous economies of scale and are not suitable for fields in the range of 0.25 to 2.0 tcf.

14 A stand-alone ammonia plant is not likely to be commercially viable for marginal gas fields because ammonia must be stored and transported under pressure. An alternative is to build a urea plant adjacent to the ammonia plant. The combined economics remain poor, however.

15 Because of the simplified nature of the analysis in this study, the above comments, as well as the gas values given in Table 1, are not meant to be seen as definitive assessments of a specific process as applied to a particular gas field. What is important is that fields around the world could be subjected to examination under the broad criteria used in this study for size, location, proximity to market, and gas value as a way of getting a good first approximation of their commercial potential.

1

Introduction

Objectives of the Study

1.1 Many natural gas reservoirs around the world are currently too small, or too remote from sizable population centers, to be developed economically. Similarly, a great deal of the world's natural gas is associated with liquid hydrocarbons, and producers often maximize the extraction of these more valuable liquids even when it means losing the associated gas through flaring. Yet natural gas is among the most efficient and environmentally benign fuels available. Hence, if reservoirs that are now only marginally economic producers of gas could be made commercially viable, the world would gain a significant increment in efficient, clean energy.

1.2 In Africa, under the auspices of the Africa Gas Initiative (AGI), the World Bank has been supporting efforts to create local and regional markets for natural gas and liquefied petroleum gas (LPG) that will help domestic marginal gas fields become commercial. The AGI aims at promoting development of gas fields; at identifying and encouraging economic investments in gas-using industries, including power generation; and at establishing appropriate incentive and regulatory systems. The work thus far has focused on finding uses for gas or addressing market imperfections that inhibit investors from coming in on their own. In many areas, however, such efforts will not be sufficient to make marginal fields commercial.

1.3 The present study reviews the available and emerging technological options to obtain a clearer understanding of the potential economic benefits of commercializing marginal gas fields. In particular, the study examines technologies suitable for small gas fields. Although the report focuses on Africa, its general conclusions on the commercial viability of the technologies considered are valid worldwide.

1.4 The study comprised the following steps:

- Reviewing possible and potential gas uses and technologies, both through literature searches and telephone interviews.

- Identifying "nontraditional" technologies—an activity that incorporated visits to manufacturers, investors, and technical experts in the United States and Europe to obtain information on the latest developments and key data and references on the technologies—and assessing the interest of the key players in applying the technologies to marginal gas fields.
- Procuring critical data on typical marginal gas fields in southern and western Africa for use as "reference fields" in an assessment of possible sample projects.
- Reviewing potential markets for the products of these fields.
- Performing a technical and economic assessment of potential technologies to identify the most promising among them.
- Listing the relevant plant manufacturers and technology licensers.

The data used in the study were obtained largely from the sources shown in Table 1.1.

Small Fields in Africa

1.5 The focus of this study is small gas fields, onshore as well as offshore, and containing associated as well as nonassociated gas. The fields may range in size from 0.25–2.0 tcf. Although these gas fields are small by international standards, the largest of them can support a number of standard production plants. Table A1.1 in Annex 1 gives the number of small, medium, and large (world-scale) production plants that can be supported by the gas supply from different field sizes based on 25 years of production, which could be regarded as a maximum economic life for standard gas consumption plants. As Table A1.1 shows, carbon black, small methanol plants, ammonia-urea and iron-reduction facilities require comparably small amounts of gas annually, whereas gas-to-olefins (GTO), synthetic fuel, synthetic crude, and dimethyl ether (DME) plants require larger annual gas flows.

1.6 Data from published and unpublished sources were used to review production sites in southern and western Africa (excluding Nigeria on account of their large gas field sizes). The fields were categorized by size as being less than 0.1 tcf, between 0.1 tcf and 0.25 tcf, between 0.25 tcf and 0.5 tcf, between 0.5 tcf and 1 tcf, and between 1 tcf and 2 tcf. The results are summarized in Annex 1. As expected, southern and western Africa have a significant number of very small fields, most of them with less than 0.1 tcf in gas reserves. Although more than 85 gas fields have reserves of less than 0.25 tcf, only 8 fields have reserves between 0.25 tcf and 0.5 tcf, and another 8 have between 0.5 tcf and 1.0 tcf.[2]

[2] The sources for these data were a study undertaken for the Southern African Development Community (SADC), *Study of the Economics of Natural Gas Utilisation in Southern Africa, Technical Paper A: Southern African Gas Markets* (Cape Town, May 1995), referred to as the SADC Gas Utilization Study hereafter, and gas field data purchased from Petroconsultants (United Kingdom).

Table 1.1 Sources of Data for Emerging Natural Gas Technologies

Aker Maritime A/S, Oslo, Norway	Lurgi Oel Gas Chemie GmbH, Frankfurt, Germany
Aker Maritime Inc., Houston, Texas, United States	Lurgi Metallurgie GmbH, Frankfurt, Germany
Black & Veatch Prichard, Overland Park, Kansas, United States	Linde AG, Munich, Germany
Costain Oil, Gas & Process Ltd., United Kingdom	MW Kellogg Limited, London, United Kingdom
Conoco Inc., Houston, Texas, United States	Mustang Engineering Inc., Houston, Texas, United States
Dickson GMP International, New Orleans, Louisiana, United States	Norsk Hydro A/S, Oslo, Norway
DSND Offshore, Grimstad, Norway	Rentech Inc., Denver, Colorado, United States
Exxon Research and Engineering Company, Florham Park, New Jersey, United States	Sasol Synfuels International, Johannesburg, Republic of South Africa
Gas Research Institute (GRI), Chicago, Illinois, United States	Solco Energy AS, Stavanger, Norway
Haldor Topsøe A/S, Copenhagen	Statoil, Stavanger, Norway
Hindsford Pty. Ltd., Victoria, Australia	Stewart & Stevenson Operations, Inc., Houston, Texas, United States
Dr. Leiv Kolbeinsen, Carnegie Mellon University, Pittsburgh, Pennsylvania, United States	Syntroleum Corporation, Tulsa, Oklahoma, United States
Krupp Uhde GmbH, Dortmund, Germany	Andreas Ugland & Sons, Grimstad, Norway
Kværner Engineering A/S, Oslo, Norway	UMC Petroleum Corporation, Houston, Texas, United States
	Voest Alpine Industrieanlagebau, Linz, Austria

1.7 A few fields in the required size groups are listed in Table A1.2 in Annex 1. The fields are characterized by the current status, reserve size, location, production rate, production cost, and distance to the nearest main market. Not all information to construct the table was available. In particular it was difficult to obtain production cost data.

2

Methodology

2.1 The technical and economic review conducted for this report comprised the following tasks:

- Identification of potential technologies for utilizing natural gas.
- Selection of two or three plant sizes for each technology.
- Assessment of the market for end-products, including the product price.
- Estimation of capital expenditures (capex), operating and maintenance costs, and gas consumption.
- Calculation of the gas value for each plant size.
- Sensitivity analysis with respect to product price and investment cost variations.

Technologies Reviewed

2.2 The data for each technology were obtained from literature reviews, direct communication with the listed suppliers, visits to the suppliers, and follow-ups through writing or by telephone. The processes reviewed are listed in Table 2.1.

Table 2.1 Processes Reviewed

Process	*Unit*	*Capacity*		
		Large	*Medium*	*Small*
Methanol synthesis	t/d	2,500	1,500	600
Methanol on FPSO	t/d	1,500	900	600
Ammonia synthesis	t/d	1,800	1,000	—
Ammonia and urea	t/d	3,100	1,700	—
Synthetic fuels	b/d	20,000	10,000	5,000
Synthetic crude on FPSO	b/d	—	10,000	5,000
Dimethyl ether synthesis	t/d	4,300	1,800	—
Gas-to-olefins	t/d	2,400	1,500	1,200
Iron ore reduction (DR)	t/d	2,900	—	—
Carbon black	t/d	120	—	—

Note: FPSO = floating, production, storage, and off-loading; DR = direction reduction; t/d = metric tons per day; b/d = barrels per day; — = not examined.

Basic Technical Elements

2.3 Various technical aspects considered in the analyses are described below.

Main Categories for Use of Natural Gas

2.4 All potential uses of natural gas fall into one of the following categories:

(a) *Burn* (in a flare, in a power plant, or in any other burner).

(b) *Reinject* (into the reservoir).

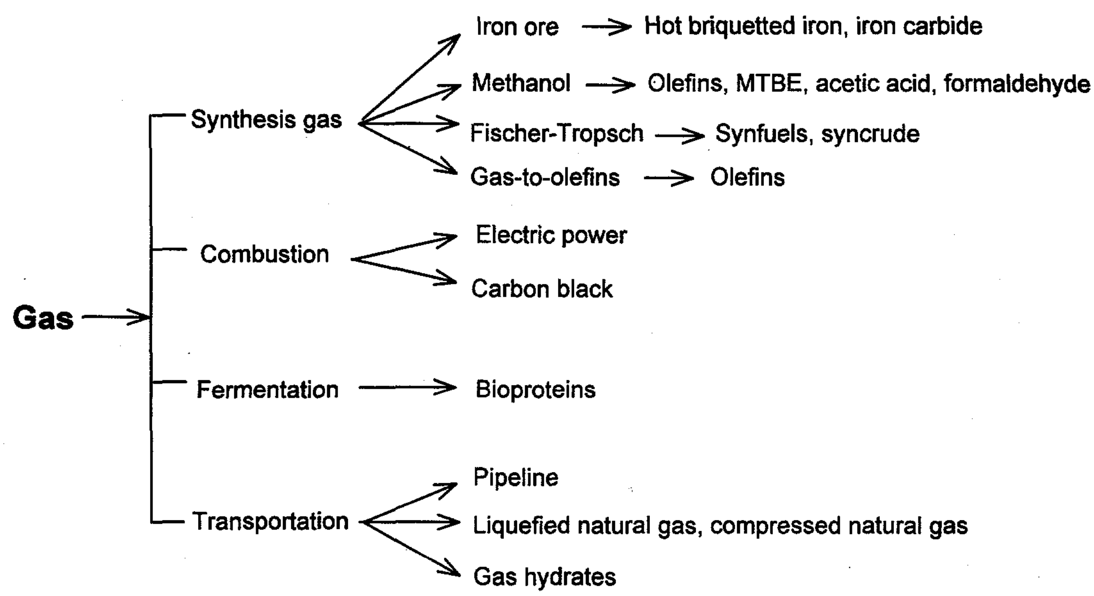
(c) *Move* (to a market by pipeline, liquefied natural gas, Ugland gas liquid, or as hydrates).

(d) *Convert* (chemically to other energy carriers).

(e) *Use* (for reduction of iron ore and for other metallurgical purposes).

The technologies addressed in this report focus mainly on categories (d) and (e), but exclude conversion of methanol to formaldehyde, acetic acid, and methyl tertiary butyl ether (MTBE), as well as generation of electric power. Figure 2.1 illustrates different uses of natural gas.

Figure 2.1 Uses of Natural Gas



Synthesis Gas

2.5 Most of the processes discussed in this report are based on using synthesis gas as a feedstock. Synthesis gas, or syngas, is a mixture of hydrogen and carbon monoxide (CO). Syngas may be produced from a multitude of feedstocks, including coal, oil, naphtha, and natural gas. At present, most syngas is made from natural gas. Syngas is used in the production of methanol, synfuels, and DME, as well as in the reduction of iron ore. Its production is also the first step in the gas-to-olefins (GTO) process, whereby natural gas is converted to syngas, syngas to methanol, and finally methanol to olefins (MTO). The hydrogen from syngas is also used in the production of ammonia.

2.6 The chemistry and the nickel-based catalyst used in converting natural gas to syngas are well understood. Hence, attempts to improve the classical one-step steam-reforming process have focused on reducing the energy consumption, size, and cost of the plant. In this regard, areas being examined for improvements are heat integration, mechanical design, and metallurgy. A brief description of different syngas processes is given in Annex 2.

Economies of Scale

2.7 The capex for different-sized, single-train plants do not increase linearly with increasing unit size. A basic rule of thumb in the industry is to employ a "scaling factor" of 0.65 to 0.70 for this purpose. Thus, if the capex for a given plant is $100 million, the capex of a plant twice as large is calculated as

$$\$100 \text{ million} \times 2^{0.65} = \$157 \text{ million},$$

rather than simply multiplying 100 million by 2 to obtain $200 million. The present report uses a scaling factor of 0.65.

Localization Factors

2.8 Localization factors reflect local conditions, such as the existing infrastructure, the cost of transporting equipment to the gas field, and the cost and efficiency of labor and management. For a greenfield plant in a developing country, this factor typically ranges between 1.3 and 2.0. This factor could be incorporated systematically for a given location by assigning add-on percentages, relative to the U.S. Gulf Coast, for a specific number of cost elements, such as engineering, procurement, construction, management, materials (equipment and bulk), and labor costs of expatriates. This report examines localization factors ranging between 1.0 and 2.0. The gas value computed at a localization factor of 1.0 is referred to as the "base case." Such a low localization factor is unlikely in Africa. Nonetheless, the base case is considered because it is equivalent to a case in which the localization factor is higher than 1.0, but the U.S. Gulf Coast–based capex was overestimated by the same factor—for example, a 30 percent reduction in capex at a localization factor of 1.3. In addition, for some gas fields elsewhere in the world, the localization factor may be close to unity, and the gas value in the base case would indeed be applicable. The summary table (Table 3.11; see also Table 1 in the overview) comparing different technologies is compiled from the results of the calculations using a localization factor of 1.3.

Feedstock Price

2.9 The price of natural gas on the open market could vary widely, from $2.50/MMBtu in an established industrial climate, to $0.50 per MMBtu or lower if little or no alternative market exists for the gas. An assumed gas price of $0.50/MMBtu is commonly used in decisions to contract new, large, gas-fed plants in remote locations. The price of associated gas could in fact be taken as nil or even negative if the alternative is to flare the gas for a penalty or reinject it at high cost, or the inability to produce oil on account of the presence of associated gas. The feedstock cost would be the gas price ($/MMBtu) multiplied by the specific gas consumption.

2.10 In this study, the price of natural gas is not assumed. Instead, the price of gas that would make the net present value (NPV) zero at a discount rate of 15 percent is calculated, as discussed below.

Use of FPSOs for the Process Plants

2.11 The idea of mounting a 1,000–1,500 tons per day (t/d) steam-reforming-based methanol plant on a ship or a barge has been proposed for many years. Aker

Engineering and Ugland Offshore have proposed a North Sea version for producing oil from subsea wells at 60,000 barrels per day (b/d) and converting the associated gas to chemical grade methanol at a rate of 900 t/d. Solco Trading in Stavanger, Norway, has proposed a similar concept, with a focus on testing and early production capabilities. ICI Katalco is designing a floating methanol plant for BHP in Australia. Sasol and Statoil, in collaboration with Aker Engineering and Foster Wheeler, are working on a similar concept, where the methanol production is replaced by a Sasol syncrude (synthetic crude oil) plant. Aker/Ugland have also proposed a floating methanol plant, up to 1,500–2,000 t/d on a simple barge, for Southeast Asian waters. None of these proposals have yet been commercialized, but interest in such plants and awareness of their potential advantages have been significant (Annex 3 describes advantages and disadvantages of FPSO).

"Packaged Projects"

2.12 The individual processes discussed are treated chiefly on a stand-alone basis. However, the advantages of "packaged projects" should be given due consideration when evaluating gas utilization. A stand-alone plant must develop its own infrastructure, such as the harbor, roads, site preparation, buildings, offices, power plant, water treatment plant, and administration. The advantages of sharing these infrastructure costs among two or several production units are obvious, although the combined plant gas consumption may exceed the amount of available gas for smaller fields (Annex 3 provides some examples of packaged projects).

Personnel and Training

2.13 All the gas conversion plants discussed in this report are expensive and complex, requiring significantly skilled and experienced personnel to operate and manage them—particularly in the areas of plant safety and maintenance. An example is the maintenance of highly sophisticated compressors that are critical components in all the plants.

2.14 Although a long-term objective is to staff these plants predominantly with local personnel, in the foreseeable future a significant proportion of the personnel in any of these plants will likely be expatriates. With efficient and successful training programs the long-term expatriate proportion may possibly be brought down to below 10 percent, but such reductions could take a number of years to achieve.

General Assumptions for Each Technology

2.15 The following general assumptions have been used in the assessment of each process option:

- 340 operating days per year.[3]

[3] This implies a downtime of only 25 days per year; this is standard for modern plants, but may be somewhat optimistic for African conditions.

- Single unit annual capacity = daily capacity × 340, unless annual capacity is the starting basis.
- Unless otherwise stated, the capex is based on suppliers' data for battery limits (U.S. Gulf Coast), with 50 percent added for offsites. Offsites contain the required installations outside the process plant proper for boiler feed water, cooling water, process water, electric power, and any other utilities necessary for the process plant. A well-recognized industry practice is to take this as 50 percent of the inside battery limit cost, in lieu of carrying out a more rigorous cost estimate for the entire plant.
- Unless otherwise stated, the maintenance cost is taken as 3 percent annually of the total capital cost. The percentages are given in the tables; they are higher for processes that involve much solids handling (urea synthesis and DR) and lower for DME and carbon black, as specified by the licensers.
- The operating cost is based either on overall data from suppliers or figures generally applicable in the industry.
- A construction period of three years, with the capex equally distributed, is assumed. In some cases it could be shorter.
- The useful life of the plant is assumed to be 25 years.

2.16 The production rate of associated gas depends on the oil flow rate and gas-to-oil ratio (GOR). The GOR usually changes with time and decreasing pressure. Consequently the gas production rate will normally not be constant over time, as is assumed in this report. A possible solution for securing a more stable gas production rate is to install water injection equipment. Now a common practice in most oil fields, water injection gives pressure support to the oil formation, increases oil recovery, maintains the pressure of the oil formation and thus the gas pressure and rate of production of associated gas. It may in fact be efficient to keep the rate of gas production constant by adjusting the rate of water injection.

2.17 The following factors have not been considered in this study:

- Working capital.
- Escalation of costs beyond 1997.
- Training programs.
- Contingencies.
- Import taxes and customs duties.
- Unusual expenses to ensure water, electricity, and so on.
- Infrastructure such as roads, railroads, piers and port, communications network, and housing.

The magnitude of these costs can be established only through detailed on-site investigations that are outside the scope of this study. Still, because most of these costs are comparable for different processes in the same location, omitting them should not alter the ranking of projects significantly.

Calculation of Gas Value

2.18 The gas value or market value of gas is a key indicator of the viability of a gas project. It is defined as the maximum price that can be charged for gas at the burner tip for different uses that maintains the competitiveness of the project. In a comparison of different processes for a given gas field, the one giving the highest gas value is clearly the best choice, subject to possible adjustments to reflect proximity to local product markets, supply costs, and so on, or any plants needed downstream of the plant in question (for example, gas to methanol and methanol to olefins, followed by a polyolefin plant). The gas value is calculated for each process, and its sensitivity to changes in capex and product price is examined. Because the effects of varying the capex and product price are significant, the computed gas values should be regarded as order-of-magnitude estimates only. As a first approximation, a process may be considered commercially viable if the gas value exceeds $0.50/MMBtu.

3

Techno-Economic Analysis

Methanol Synthesis

3.1 Both onshore and offshore methanol plants were evaluated.

Onshore Plants

3.2 The objective of methanol synthesis is to convert natural gas to fuel- or chemical-grade methanol using the appropriate process among several options, the best of these being dependent on the plant capacity. Annex 4 provides a full description of methanol synthesis, including an example of how the gas value is calculated and the sensitivity analysis conducted.

3.3 World production of methanol in 1997 was an estimated 29 million t. Total African output was an estimated 0.8 million t. Some 70 percent of world methanol production is used in the synthesis of chemicals, particularly formaldehyde (40 percent); MTBE, which is used as an octane enhancer for gasoline (20 percent); and acetic acid. Methanol is also used as an energy source, although high costs have inhibited market growth. World-market methanol prices have traditionally varied between \$120 and \$180/t. In June 1997, the price of methanol was \$180/t in Rotterdam and \$240/t in Singapore.

3.4 Today, "world class" methanol plants have production capacities on the order of 2,000–2,500 t/d. Many older plants have capacities of 1,000 t/d or even less. The methanol process comprises three main stages:

- Desulfurization and preparation of syngas.
- Syngas compression and methanol synthesis.
- Purification of the final product.

3.5 Nearly all methanol is made from natural gas today. Methanol plants with high efficiency consume about 30 gigajoules per metric ton (GJ/t) of methanol or 30,000 standard cubic feet (scf) of methane per metric ton. This report uses a conservative figure of 32,000 scf methane per metric ton of methanol produced.

3.6 An innovative event affecting the methanol market could be the successful development of large-scale DME, MTO, or GTO processes (see Annexes 7 and 8). Low-cost crude (undistilled) methanol from very large plants would be required for these processes. Table 3.1 presents the key results for different sizes of onshore methanol plants.

Table 3.1 Characteristics and Economic Analysis of Onshore Methanol Plants

		Capacity		
Data item	*Unit*	*Large*	*Medium*	*Small*
Capacity, consumption, and economic data				
Daily methanol capacity	t/day	2,500	1,500	600
Capex, including offsites	million $	300	220	120
Feed gas consumption	billion scf/year	27	16	6.5
Sale price	$/t	145	145	145
Gas consumption, 25-year lifetime	tcf	0.68	0.41	0.16
Gas values				
Localization factor 1.0 (base case)	$/MMBtu	2.1	1.6	0.4
Localization factor 1.3	$/MMBtu	1.4	0.7	-0.8
Localization factor 1.5	$/MMBtu	0.9	0.1	-1.6
Localization factor 1.75	$/MMBtu	0.3	-0.6	-2.6
Localization factor 2.0	$/MMBtu	-0.3	-1.3	-3.6

3.7 In the base case (which is also equivalent to a 30 percent reduction in capex at a localization factor of 1.3), both 2,500 b/d and 1,500 b/d plants are commercially viable. At a localization factor of 1.3, the 1500 t/d plant is economic at the product price of $145/t, but cannot sustain even a 5 percent fall in product price. The 2,500 t/d plant can sustain a drop in product price of 15 percent, giving a gas value of $0.7/MMBtu, but if the product price falls by 20 percent, the gas value falls to $0.4/MMBtu. At a localization factor of 1.5, only the 2,500 b/d plant is economic. At a localization factor of 1.75, product price increases of 5, 25, and 70 percent are needed to raise the gas value above $0.5/MMBtu for the 2,500, 1,500, and 600 t/d plants, respectively.

3.8 Only a limited local market exists for methanol in Africa, and the market is likely to remain so unless a methanol-consuming industry is established, such as that for the conversion of methanol to formaldehyde, formaldehyde-urea to industrial adhesives, and methanol to MTBE.

3.9 Recently, Atlantic Methanol Production Company contracted with Raytheon to build a 2,500 t/d grassroots methanol plant on Bioko Island of Equatorial Guinea. Gas feed for the plant will come from Alba field off Equatorial Guinea. Raytheon expects to complete the plant, including a desalinization unit for seawater and an electric power generation system, by the end of 2000.

FPSO

3.10 The mounting on a ship or a barge of a 1,000 to 1,500 t/d steam-reforming-based methanol plant has been proposed for many years, but no such plant has yet been built or contracted. Solco Trading, Stavanger, has proposed a floating methanol plant for 2,700 t/d of methanol and 50,000 b/d of crude with a North Sea–going vessel. ICI Katalco is developing an FPSO version for BHP in Australia. Aker/Ugland is developing a barge-mounted 1,500 to 2,000 t/d methanol plant for a Southeast Asian location. The key results for medium-sized methanol plants on an FPSO are shown in Table 3.2

Table 3.2 Characteristics and Economic Analysis of Medium-Sized Methanol Plants on an FPSO

		Capacity		
Data item	*Unit*	*Large*	*Medium*	*Small*
Capacity, consumption, and economic data				
Daily methanol capacity	t/day	1,500	900	600
Capex, including offsites	million $	180	135	100
Feed gas consumption	billion scf/year	16	9.8	6.5
Sale price	$/t	145	145	145
Gas consumption, 25-year lifetime	tcf	0.41	0.24	0.16
Gas values				
Localization factor 1.0 (base case)	$/MMBtu	1.7	1.0	0.6
Localization factor 1.3	$/MMBtu	1.0	0.1	-0.5
Localization factor 1.5	$/MMBtu	0.5	-0.5	-1.1
Localization factor 1.75	$/MMBtu	-0.1	-1.3	-2.0
Localization factor 2.0	$/MMBtu	-0.7	-2.0	-2.8

3.11 As seen from Table 3.2 only the 1,500 t/d plant can be considered economic at the product price of $145/t at localization factors of 1.3 and 1.5. At a localization factor of 1.5, product price increases of 25 percent and 35 percent would be required to raise the gas value above $0.5/MMBtu for the 900 and 600 t/d methanol plants, respectively.

Ammonia and Urea

3.12 Stand-alone ammonia plants as well as ammonia–urea complexes were considered in this study.

Ammonia

3.13 This concept, more fully described in Annex 5, is to convert natural gas to ammonia (NH_3), and possibly further to urea. World ammonia production reached 96 million t in 1996. Some 85 percent of the ammonia produced is used to make fertilizers, the most important being urea. The remaining 15 percent of the world's ammonia output goes into a variety of industrial products, including animal feeds, explosives, and polymers. World-market prices of ammonia have varied between \$100 and \$230/t over the last five years. The 1997 price level of \$220/t is expected to hold in the near future.

3.14 Ammonia plant capacities vary over a wide range, but most plants in operation are in the range of 1,000–2,000 t/d. Nearly all the world production of ammonia is based on natural gas. Syngas is produced in a tubular steam reformer followed by an air-blown secondary reformer. The syngas is then purified by converting all carbon monoxide (CO) to carbon dioxide (CO_2) and removing the CO_2. The hydrogen (H_2) thus obtained is combined with nitrogen (N_2) from air to make anhydrous ammonia in a catalytic converter. Natural gas, after the removal of CO_2 and hydrogen sulfide (H_2S), is the principal feedstock and accounts for more than 80 percent of the world's ammonia production. High-efficiency plants use about 33 GJ/t of ammonia. The results of economic analysis for ammonia plants are shown in Table 3.3.

3.15 Both plants are economic at the capex based on the U.S. Gulf Coast. At a localization factor of 1.3, a 15 percent product price increase would be required to raise the gas value of the 1,000 t/d plant above \$0.5/MMBtu. At a localization factor of 1.5, the product prices would need to increase by 5 and 30 percent, respectively, for the 1,800 t/d and 1,000 t/d plants to raise the gas value above \$0.5/MMBtu. The corresponding figures at a localization factor of 1.75 are 20 and 45 percent, respectively.

Table 3.3 Characteristics and Economic Analysis of Ammonia Plants

		Capacity	
Data item	*Unit*	*Large*	*Medium*
Capacity, consumption, and economic data			
Single unit daily capacity	t/day	1,800	1,000
Capex, including offsites	million $	280	190
Feed gas consumption	billion scf/year	20	11
Sale price for ammonia (FOB)	$/t	165	165
Gas consumption, 25-year lifetime	tcf	0.51	0.28
Gas values			
Localization factor 1.0 (base case)	$/MMBtu	1.8	1.0
Localization factor 1.3	$/MMBtu	0.9	-0.1
Localization factor 1.5	$/MMBtu	0.3	-0.9
Localization factor 1.75	$/MMBtu	-0.5	-1.8
Localization factor 2.0	$/MMBtu	-1.3	-2.8

Note: FOB = free on board.

Urea

3.16 Ammonia is seldom sold directly in Africa, and commercialization will depend on being able to sell the product on the world market or the existence of a local manufacturer of fertilizers, for example, urea. Fertilizers may be sold locally, as well as on the world market.

3.17 World urea production will reach an estimated 40 million t in 1997. African production is estimated at 2.6 million t in 1997. Urea is the most popular of the nitrogen-based fertilizers because of its very high nitrogen content. Urea is especially well suited for rice crops. Prices of urea have varied between $110 and $230/t in the 1990s.

3.18 Commercial production of urea is based on CO_2 and ammonia. The reaction proceeds in two steps: formation of ammonium carbamate and dehydration of ammonium carbamate to urea. Plant capacities vary between 500 t/d and 2,000 t/d. An ammonia plant capacity of 1,000 t/d gives urea production of 1,740 t/d. The key results for combined ammonia-urea plants are shown in Table 3.4.

3.19 At a localization factor of 1.3 or higher, a substantial reduction in capex or increase in product price would be required to make this process commercially viable. At a localization factor of 1.3, a product price increase of 15 and 40 percent would be needed to bring the gas value up to $0.5/MMBtu for the larger and smaller plant sizes, respectively.

Table 3.4 Characteristics and Economic Analysis of Ammonia-Urea Plants

		Capacity	
Data item	*Unit*	*Large*	*Medium*
Capacity, consumption, and economic data			
Single unit urea capacity	t/d	3,130	1,740
Capex, including offsites	million $	510	350
Feed gas consumption	billion scf/year	23	13
Sale price for urea	$/t	145	145
Gas consumption, 25-year lifetime	tcf	0.58	0.32
Gas values			
Localization factor 1.0 (base case)	$/MMBtu	1.1	-0.3
Localization factor 1.3	$/MMBtu	-0.5	-2.3
Localization factor 1.5	$/MMBtu	-1.6	-3.6
Localization factor 1.75	$/MMBtu	-2.9	-5.2

Synthetic Fuels

3.20 For this concept, known as gas-to-liquids (GTL) and further described in Annex 6, natural gas is converted to synthetic liquid fuel (either synthetic crude oil or synthetic high grade, clean-burning diesel) using a modern version of the well-known Fischer-Tropsch process first developed in Germany in the 1920s. Both onshore and offshore processes were examined in this study.

3.21 In principle, the market for crude oil and diesel substitutes is practically unlimited. If the total world crude production is 60 million b/d, it would take well over 200 tcf of gas per year to produce the equivalent quantity of crude from natural gas. For a world crude price of $18–$19 per barrel (bbl), the market price at the production site of the finest paraffinic diesel available corresponds to about $25/bbl. Because it may not be possible to sell all the diesel produced at this elevated price, an intermediate price for high-quality diesel or diesel blend stock of $22/bbl is used in this study.

3.22 Plant costs for synthetic fuel production are still very high, and commercial considerations are currently given to very large plants, on the order of 20,000–50,000 b/d, by some of the major developers of this technology, including Exxon and Sasol. Others, including BP, Hindsford, Rentech, and Syntroleum, claim to be close to commercializing plants as small as 2,500–5,000 b/d. Such plants would enable economic development of gas reserves that are currently seen as too small, too remote, or both. Processes of number of companies are discussed in Annex 6, including those Mobil has commercialized in New

Zealand, Shell in Malaysia, Sasol in South Africa, and announcements made by BP, Exxon, Hindsford, Rentech, and Syntroleum.

3.23 Except for Mobil's methanol-to-gasoline technology, all the other processes currently offered for producing synthetic crude or fuel from natural gas involve the following steps:

- Syngas generation, converting natural gas and steam into a 2:1 mixture of hydrogen and CO, which feeds into the Fischer-Tropsch (F-T) reactor.
- F-T synthesis, converting syngas into long chain hydrocarbons using any of the available reactor types (fixed, fluidized, or slurry bed).
- Upgrading of the F-T products to the desired marketable product, chiefly by a combination of distillation, along with hydrogenation or mild hydrocracking, or both.

3.24 It is generally agreed that it takes 10 GJ or 10,000 scf of natural gas to produce 1 bbl of syncrude or synfuels. From the point of view of the present study, which deals with gas reserves of up to 2.0 tcf, the upper limit of relevant synfuel plant capacities is about 23,000 b/d. However, the maximum synfuel capacity would be below 10,000 b/d for the majority of the fields considered in this report.

Land-Based GTL Plants

3.25 Estimated investment costs for GTL plants vary widely from one technology company to another; the range spans \$15,000 to \$30,000 per daily barrel capacity, depending on the plant capacity and the specific technology. The lowest published estimates are \$18,000 to \$22,000 per daily barrel capacity for a 5,000 b/d plant and \$15,000 to \$16,000 per daily barrel capacity for a 10,000 b/d plant. In the following evaluations a conservative figure of \$30,000 per daily barrel capacity for a 10,000 b/d plant is used, because only this figure has been demonstrated commercially. The key results for synfuel plants are shown in Table 3.5.

3.26 As Table 3.5 shows, a substantial reduction in capex would be required to make this process economic. Although variation in localization factor is separated from capex reduction, any change in capex may be regarded as a result of varying localization factor or change in capex at source—that is, U.S. Gulf Coast. Because the trend in GTL is expected to be in the direction of decreasing capex, a capex reduction of up to 50 percent is considered in Table 3.5. For a more realistic localization factor of 1.3 or higher, a 50 percent reduction in capex relative to the base case would correspond to a U.S. Gulf Coast capex reduction of 65 percent or higher. For the 10,000 b/d plant, the product price would have to increase by more than 15 percent to raise the gas value to \$0.5/MMBtu at a localization factor of 1.0 and no change in capex. For the 5,000 b/d plant, the corresponding increase in product price required would be 45 percent. A 50 percent reduction in capex corresponds to \$12,000, \$15,000, and \$19,000 per daily barrel capacity for the 20,000 b/d, 10,000 b/d, and 5,000 b/d plant sizes, respectively, on a U.S. Gulf Coast basis. Even a 50 percent reduction in capex, however, is barely sufficient to make the 5,000 b/d plant economic. Including a localization factor of 1.3 or higher would make the process even more uneconomic. To raise the gas value of the 5,000 b/d plant above $0.5/MMBtu, the capex needs to fall to $19,000 per daily barrel capacity or lower, including the localization factor. At a localization factor of 1.3, the U.S. Gulf Coast capex would have to fall to less than $15,000 per daily barrel capacity.

Table 3.5 Characteristics and Economic Analysis of Synfuel Plants

		Capacity		
Data item	*Unit*	*Large*	*Medium*	*Small*
Capacity, consumption, and economic data				
Single unit daily capacity	b/d	20,000	10,000	5,000
Capex, including offsites	million $	470	300	190
Feed gas consumption	billion scf/year	68	34	17
Sale price	$/bbl	22	22	22
Gas consumption, 25-year lifetime	tcf	1.7	0.85	0.43
Gas values				
Localization factor 1.0 (base case)	$/MMBtu	0.6	0.1	-0.6
Localization factor 1.0, 30% capex decrease	$/MMBtu	1.0	0.6	0.1
Localization factor 1.0, 50% capex decrease	$/MMBtu	1.2	1.0	0.5
Localization factor 1.3	$/MMBtu	0.2	-0.4	-1.2
Localization factor 1.5	$/MMBtu	-0.1	-0.7	-1.6

Syncrude Plant on FPSO

3.27 Table 3.6 shows analogous figures for a syncrude plant on an FPSO. As Table 3.6 indicates, even if the capex were halved, neither plant would be economic if the price of synthetic crude is $16/bbl. If a 30 percent increase in capex is accompanied by a 50 percent increase in the price of crude (that is, $24/bbl), then the 10,000 b/d has a gas value of $0.9/MMBtu at a localization factor of 1.0, but the 5,000 b/d plant remains uneconomic. As before, a substantial reduction in capex is needed before this technology can be considered on a commercial basis.

Table 3.6 Characteristics and Economic Analysis of Syncrude Plants on an FPSO

		Capacity	
Data item	*Unit*	*Medium*	*Small*
Production, consumption, and economic data			
Syncrude daily production	b/d	10,000	5,000
Capex	million $	250	160
Feed gas consumption	billion scf/year	34	17
Sale price	$/barrel	16	16
Gas consumption, 25-year lifetime	tcf	0.85	0.43
Gas values			
Localization factor 1.0 (base case)	$/MMBtu	-0.3	-1.0
Localization factor 1.0, 30% capex decrease	$/MMBtu	0.1	-0.4
Localization factor 1.0, 30% capex decrease, 50% price increase	$/MMBtu	0.9	0.4
Localization factor 1.0, 50% capex decrease	$/MMBtu	0.4	-0.1
Localization factor 1.3	$/MMBtu	-0.7	-1.5

Dimethyl Ether (DME)

3.28 The objective of this process, described more fully in Annex 7, is to convert natural gas to DME by catalytic dehydration to produce a gas that can be used as a clean-burning diesel substitute. DME is a gas at ambient pressure and temperature, but it can be transported and stored under pressure as a liquid as in the case of LPG (at 5 bar and ambient temperature).

3.29 Conventional use of DME is as an aerosol propellant. Current world DME production is 150,000 t/y, but the potential market is much larger for DME as a clean and efficient diesel fuel substitute. The price of DME as a diesel substitute is taken as that of high-grade diesel, about $25/bbl or $190/t.

3.30 DME is currently produced in three steps: conversion of natural gas to syngas, formation of methanol from syngas, and dehydration of methanol to DME. Topsøe's new DME process combines the latter two steps into one process in which three reactions take place simultaneously in one reactor:

- Conversion of syngas to methanol.
- Conversion of CO and water to CO_2 and hydrogen, and removal of CO_2.

- Dehydration of methanol to DME and water.

3.31 The feedstock is natural gas, requiring 44,400 scf/t of DME. Economies of scale call for very large plants, ranging from 1,800 to 7,000 t/d of DME. The plant sizes evaluated here are 1,800 t/d and 4,300 t/d. Table 3.7 gives key results for DME.

Table 3.7 Characteristics and Economic Analysis of DME Plants

		Capacity	
Data item	*Unit*	*Large*	*Medium*
Capacity, consumption, and economic data			
Single unit daily capacity	t/d	4,300	1,800
Capex, including offsites	million $	525	275
Feed gas consumption	bcf	65	27
Sale price	$/t	190	190
Gas consumption, 25-year lifetime	tcf	1.6	0.68
Gas value			
Localization factor 1.0 (base case)	$/MMBtu	2.7	2.2
Localization factor 1.3	$/MMBtu	2.2	1.6
Localization factor 1.5	$/MMBtu	1.8	1.1
Localization factor 1.75	$/MMBtu	1.4	0.6
Localization factor 2.0	$/MMBtu	1.0	0.1

3.32 As seen from Table 3.7, the 4,300 t/d plant is commercially feasible in all cases, even at a localization factor of 2.0. At a localization factor of 1.3, the plant can sustain a fall in product price of 35 percent; at a localization factor of 1.5, the product price can fall by 25- 30 percent, and the gas value will remain above $0.5/MMBtu. The 1,800 t/d plant is commercially viable for localization factors up to 1.75 at the specified product price. At a localization factor of 1.3, the gas value falls below $0.5/MMBtu if the product price falls by 25 percent. At a localization factor of 1.5, the gas price remains above $0.5/MMBtu after a 10 percent price reduction. If the localization factor is 1.75, no price reduction can be sustained; at 2.0, the product price would have to increase by 10 percent to bring the gas value up to $0.5/MMBtu.

Gas-to-Olefins and Methanol-to-Olefins

3.33 The gas-to-olefins (GTO) process, described in Annex 8, entails first converting natural gas to methanol, followed by converting methanol to light olefins, principally ethylene, propylene, and C_{4+} hydrocarbons. Methanol may be produced in one location and then shipped to an MTO plant at another location, or the two reactions may be carried out at a single site in a GTO plant. Either way, the process calls for considerable plant sizes.

3.34 World production of ethylene and propylene was 52 million and 27 million t, respectively, in 1994. The only African manufacturer of olefins is Algeria, which in 1994 produced 79,000 t of ethylene. Ethylene and propylene are petrochemical feedstocks; ethylene is the preferred product. Ethylene is the largest volume petrochemical produced worldwide. World price levels are in the neighborhood of \$500/t for ethylene and \$300/t for propylene. The product distribution assumed in the analyses that follow is 52 carbon mole percent ethylene, 37 percent propylene, and 11 percent C_{4+}. The selectivity to ethylene may vary between about 50 percent or lower and 65 percent depending on the operating conditions and catalyst formulation.

3.35 In this report, the entire cycle from natural gas to olefins is considered in GTO. The GTO process is discussed in Annex 8. The consumption of natural gas in GTO is about 152,000 scf/t ethylene. Table 3.8 shows key results for GTO.

Table 3.8 Characteristics and Economic Analysis of Onshore GTO Plants

		Capacity		
Data item	*Unit*	*Large*	*Medium*	*Small*
Capacity, consumption, and economic data				
Single unit annual ethylene capacity	t/y	800,000	525,000	400,000
Capex, including offsites	million \$	1,500	1,100	940
Feed gas consumption	billion scf/year	120	80	61
Sale revenue, olefins	million \$/year	580	380	290
Gas consumption, 25-year lifetime	tcf	3.0	2.0	1.5
Gas values				
Localization factor 1.0 (base case)	\$/MMBtu	1.6	0.9	0.7
Localization factor 1.3	\$/MMBtu	0.9	0.1	-0.2
Localization factor 1.5	\$/MMBtu	0.5	-0.4	-0.8
Localization factor 1.75	\$/MMBtu	-0.1	-1.1	-1.5
Localization factor 2.0	\$/MMBtu	-0.7	-1.7	-2.3

3.36 All the plants are commercially viable in the base case. At a localization factor of 1.3, only the largest plant has a gas value above \$0.5/MMBtu. All other cases considered are not commercially viable at the specified product revenues. Sale revenues from GTO may vary either as a result of changes in olefin prices or changes in product yield and product distribution (ethylene selectivity being different from 52 carbon mole percent).

At a localization factor of 1.3, increases in sale revenue of 10 and 15 percent raise the gas value above \$0.5/MMBtu for the 525,000 and 400,000 t/y plants, respectively.

3.37 As these olefins are gaseous at ambient temperature and pressure and are expensive to store and transport, a polyolefin plant (polyethylene or polypropylene) should be located adjacent to a GTO site. These are very large and expensive plants, and they neither exist in nor are planned for Africa.

Reduction of Iron Ore

3.38 Direct reduction (DR) is a process for converting iron oxides to metallic iron by using natural gas as a primary energy agent. The method is generally referred to as DR, and the product of DR is referred to as DRI (direct reduced iron). Various DR processes are discussed in Annex 9. DR is a potentially profitable way of utilizing natural gas reserves in Africa if the gas source is not too far from the source of iron ore. The products, mainly in the form of hot briquetted iron (HBI) or iron carbide, are the principal feedstock for steel production. The recommended plant sizes for new DR plants are 1–2 million t/y.

3.39 World steel production in 1995 was about 750 million t, comprising 510 million t produced by the traditional blast furnace method, 210 million t made from scrap by the electric arc furnace (EAF) method, and 30 million t by direct reduction of iron ore with natural gas (DR). DRI is a substitute for scrap in the steel-making process, and hence DRI prices have historically been tied to scrap prices. During the 1990s, prices for scrap have varied between \$90 and \$170/t. Developing countries typically have meager scrap resources, and hence close to 90 percent of world DRI production takes place in developing countries.

3.40 The feedstock for the DR processes is natural gas: 10,500–12,000 scf/t of products, using iron ore of various quality categories, including the physical state "lumpy" or "fine ore." The following affect the economics of DR: the composition of the ore, such as the iron content; the amount of residuals such as copper, nickel and cobalt, which have a detrimental impact on the physical properties of the resulting steel; and the amount of gangue (minerals such as silica, magnesia, alumina, and titania), which need to be removed during steel-making at a cost. It is beyond the scope of this study to account for these parameters in the economic calculations, and only the cost difference between "lumpy" and "fine" ore is considered. The key results for iron ore reduction are shown in Table 3.9.

3.41 A 1 million t/y Midrex plant has a gas value of \$3.3/MBtu in the base case. The value falls to \$1.8 and \$0.3 if the product price is reduced by 10 percent and 20 percent, respectively. With a localization factor of 1.3, a fall in product price of 10 percent lowers the gas value to \$0.3/MMBtu. At a localization factors of 1.5 the process cannot sustain even a 5 percent decrease in product price. The product price would need to increase by 10 and 15 percent, respectively, for localization factors of 1.75 and 2.0 to increase the gas value above \$0.5/MMBtu. A 1 million t/y "New DR" plant has a value of \$4.2/MMBtu in the base case. The process is commercially viable at a localization factor of up to 1.75. In the base case the gas value is lowered to \$0.9/MMBtu if the product price decreases by 25 percent. At a localization factor of 1.3, the process can sustain a decrease in product price of 15 percent, but if the product price decreases by 20 percent the gas value falls to \$0.3/MMBtu. At localization factors of 1.75 or higher, the process cannot sustain a price fall. Even at a localization factor of 2.0, however, a 10 percent increase in product price raises the gas value to \$1.2/MMBtu.

Table 3.9 Characteristics and Economic Analysis of Iron Ore Reduction

		Process	
Data item	*Units*	*Midrex*	*"New DR"*
Capacity, consumption, and economic data			
Single unit annual capacity	t/y	1,000,000	1,000,000
Capex, including offsites	million \$	225	230
Feed gas consumption	billion scf/year	11	12
Sale revenue	million \$/y	150	150
Gas consumption, 25-year lifetime	tcf	0.26	0.30
Gas values			
Localization factor 1.0 (base case)	\$/MMBtu	3.3	4.2
Localization factor 1.3	\$/MMBtu	1.9	2.9
Localization factor 1.5	\$/MMBtu	0.9	2.0
Localization factor 1.75	\$/MMBtu	-0.3	0.9
Localization factor 2.0	\$/MMBtu	-1.5	-0.2

Note: The "New DR" process data are based on data from two competing technology suppliers, Voest Alpine and Lurgi.

Novel Process for Carbon Black

3.42 This process, explained more fully in Annex 10, involves the combustion of natural gas to carbon black and hydrogen. A novel process for manufacturing carbon black from natural gas has been developed by Kværner Engineering. A high-temperature plasma torch in a reactor converts natural gas directly to a mixture of carbon black and hydrogen, two clean and environmentally friendly products. A carbon black plant should be located adjacent to a hydrogen user, such as a refinery or a metallurgical plant.

3.43 World production of carbon black in 1994 reached 6 million t. Prices vary significantly for different grades of carbon black, from \$600 to \$7,000/t.

3.44 Kværner's carbon black process is designed for 10,000 t/y modules, which may be built together in parallel. The plant size so far recommended by the licenser is

40,000 t/y of carbon black, with simultaneous production of about 5,000 million scf/year of hydrogen and some surplus energy (steam or electric power not included in the economic evaluation). The process consumes about 61,000 scf of natural gas and 4,400 kWh of electric power per metric ton of carbon black. Investment costs as given by the licenser are NKr 400 million (about $60 million) for a plant consisting of four modules, each with a capacity of 10,000 t/y. Table 3.10 gives key results for carbon black.

Table 3.10 Characteristics and Economic Analysis of Carbon Black Plants

Data item	*Units*	*Large*
Capacity, consumption, and economic data		
Single unit capacity	t/y	40,000
Capex, including offsites	million $	60
Feed gas consumption	billion scf/y	2.4
Sale revenue	million $/y	27
Gas consumption, 25-year lifetime	tcf	0.06
Gas values		
Localization factor 1.0 (base case)	$/MMBtu	3.7
Localization factor 1.3	$/MMBtu	2.3
Localization factor 1.5	$/MMBtu	1.4
Localization factor 1.75	$/MMBtu	0.2
Localization factor 2.0	$/MMBtu	-1.0

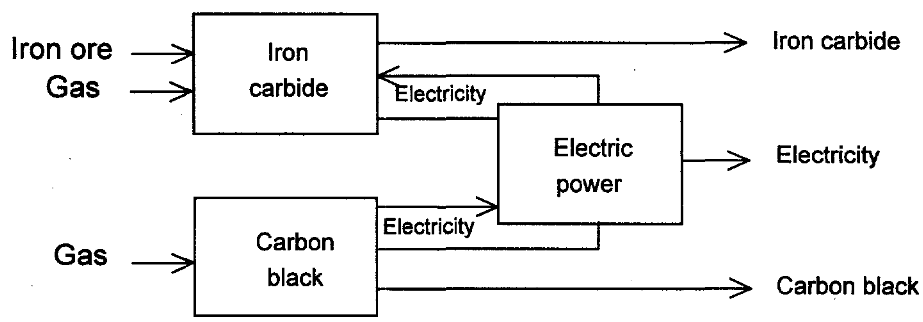
3.45 A 40,000 t/y plant has a gas value of as much as $3.7/MMBtu in the base case. If the product price is reduced by 10 and 25 percent, the gas value becomes $2.5 and $0.8/MMBtu, respectively. At a localization factor of 1.3, the process can sustain a product price reduction of 15 percent. At localization factors of 1.75 and 2.0, the product price needs to be increased by 5 percent and 15 percent, respectively, to raise the gas value above $0.5/MMBtu.

Combined Carbon Black, Iron Carbide, and Electric Power

3.46 This concept, more fully described in Annex 11, combines iron ore reduction with the production of carbon black and hydrogen. Natural gas is converted to carbon black, hydrogen, and surplus energy by the novel high-temperature plasma torch technology developed by Kværner Engineering. The carbon black process is fed by natural gas and electric power and produces hydrogen and iron carbide, along with some surplus energy in the form of steam or electric power. The data needed for an economic evaluation are not available; consequently, only a brief qualitative description is presented.

3.47 The process is highly integrated with a carefully balanced material and energy flow as shown in Figure 3.1. The principal advantage is high energy efficiency owing to optimal use of all material and energy flows. A potential disadvantage of this high degree of integration is that all the three main units need to run simultaneously. If one of them fails, the other two units may have to be shut down.

Figure 3.1 Combined Carbon Black, Iron Carbide, and Electric Power



3.48 The plant should be located close to the main feedstocks, which are iron ore and natural gas. The export products, iron carbide and carbon black, are easy to transport to their markets, and the electric power can go into an existing electricity distribution system. It might be worthwhile to study this option further for specific locations in Africa.

Bioproteins

3.49 As explained further in Annex 12, natural gas can be used as feed for a bacterium that will convert it to proteins suitable as food for poultry, farm-raised fish, and other uses. A full-scale plant for such a process is being built by Statoil in western Norway. The data needed for economic evaluation are not available, and hence only a qualitative description is given.

3.50 The idea of producing proteins by means of bacterial action from hydrocarbons such as naphtha or natural gas is not new. The former Soviet Union produced 2 million t/y of "monocell proteins." An ICI plant in the United Kingdom produces 75,000 t/d from natural gas.

3.51 Statoil, in cooperation with their partly owned subsidiary, Dansk Bioprotein, has developed a new method using a new bacterium, *Methylococcus capsulatus*, which produces high-quality proteins from natural gas. The European Union (EU) has granted an approval for using the product as animal and fish food.

3.52 Detailed data for the project are not available at present, and it has not been possible to assess the viability of bioproteins (of any type or description) for use in Africa within the scope of this study. Such an evaluation would require a study of the balance of the flow and availability of human food versus animal food in specifically defined geographic regions in Africa and the potential for trade between regions.

Ranking of Projects by Gas Value

3.53 Based on the calculations in the foregoing sections, the projects examined have been ranked in order of decreasing gas value and presented in Annex 13. A selection of projects from the annex is given in Table 3.11. It should be stressed that the gas values shown, computed using a localization factor of 1.3, give order-of-magnitude estimates only and are particularly sensitive to variations in capex and product price.

Table 3.11 Ranking of Projects by Gas Value at a Localization Factor of 1.3

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

3.54 Some of the high-ranking projects have very low annual gas use: DR, carbon black and methanol. Their lifetime gas consumption is all in the neighborhood of 0.5 tcf or less, making them suitable for small gas fields. In contrast, although DME has a very high gas value, it also requires significant gas use.

3.55 The main conclusions of the technical and economic analyses may be summarized as follows:

- The use of natural gas for direct reduction (DR) of iron oxides, which is one of the steps in steel manufacture, gives the highest gas value for gas fields in the range upwards of 0.25 tcf. New processes that can handle iron ore fines rather than pelletized or lumpy ores are particularly economically attractive. The final economics will depend on the distance between the iron ore deposit and the gas field as well as on the purity of iron ore (iron content; amount of metallic residuals such as copper, nickel, and cobalt; and amount of mineral oxides such as silica, magnesia, alumina, and titania).

- For very small gas fields, on the order of 0.1 tcf in size, a novel process for manufacturing carbon black and hydrogen from natural gas gives a high gas value for gas. The carbon black plant needs to be located close to a hydrogen consumer, such as a refinery or a DR plant.
- The economics of methanol plants for gas fields in the range 0.5–1.0 tcf are attractive. One disadvantage of methanol plants is that the distance to the nearest consumer may be substantial. The concept of methanol on an FPSO platform represents a novel technology that has several advantages as listed in this report, and it could be suitable for several of the offshore fields in Africa.
- GTL, conversion of natural gas to synfuels, is an emerging technology. At present, it appears that only large synfuel plants (20,000–50,000 b/d) consuming 2 tcf or more natural gas in a 25-year period are commercially viable, given the considerable economies of scale needed. Significant development work is under way to make smaller plants (for example, 5,000 b/d) economic. If and when the viability of small plants is commercially demonstrated, the GTL technology may be considered seriously for marginal gas fields in Africa. Such a development would represent a major breakthrough for gas utilization, not only in Africa but also worldwide and would significantly increase the total amount of economically recoverable oil and gas reserves in the world. Given the level of interest in GTL and of development work undertaken at present, it may be a short time before a breakthrough occurs. With novel syngas processes, more selective catalyst systems, and more cost-effectively engineered plants, the first profitable 5,000 b/d synfuel plant could be contracted within the next several years.
- Although the conversion natural gas to DME is economic on paper, as shown in Table 3.11, DME is not likely to emerge as a clean substitute for diesel in most parts of Africa for the foreseeable future, except possibly in South Africa. DME, a gas at ambient temperature and pressure, would require a completely new infrastructure for storage and distribution if it was to be used as a transportation fuel.
- GTO and MTO call for enormous economies of scale and are not suitable for fields in the range of 0.25–2.0 tcf.
- A stand-alone ammonia plant is not likely to be commercially viable for marginal gas fields because ammonia must be stored and transported under pressure. An alternative is to build a urea plant adjacent to the ammonia plant. The combined economics, however, are poor.
- An improvement in processes for efficient production of syngas should be followed

closely, particularly processes not requiring oxygen or new processes producing oxygen without expensive air separation plants, such as the use of ionic membranes.

4

Locational Aspects of Different Processes

General

4.1 The starting point of all the processes discussed in this report is the existence of a gas producing field. It may be a pure onshore gas field (for example, Pande in Mozambique), or a pure offshore gas field (for example, Kudu in Namibia), or an offshore oil field with associated gas (for example, Lion in Côte d'Ivoire), or an onshore oilfield with associated gas (for example, Rabi-Kuanga in Gabon). In all cases the question is whether to construct a process plant for chemical conversion of gas or for metallurgical gas usage, and if so, where to locate the plant.

4.2 Ideally, the market for the product under consideration should be close to the gas field, or the iron ore to be reduced by gas should be close to the gas field. This is rarely the case, however. Olefins (ethylene and propylene) from GTO are expensive to store and transport, and they should be produced close to their end user—for example, a polyethylene/polypropylene plant. The question then arises of whether to transport the gas to the plant location or, conversely, to locate the plant at the gas source.

4.3 For iron reduction, gas is rarely found in the same place as iron ore, and the choices hence are threefold: to transport the gas to the ore, the ore to the gas, or both gas and ore to a third location—for example, an existing steel plant or export harbor. A number of mini-steel mills, based on scrap and direct reduced iron, have been built in several African countries. Most of these, however, are operating at low rates of capacity utilization—some as low as 10 percent—and many have been shut down. The average utilization factor is about 50 percent. Thus, another locational issue would be whether to install new or more modern technology in existing plants or to establish new plants. Clearly, the former option would require incumbent or new management to establish that they can run the upgraded plant efficiently. The latter option, to establish a new plant, would allow a fresh review of the locational elements, based on the most up-to-date information.

4.4 Other factors to consider are as follows:

- An extensive industrial infrastructure and culture (including trained staff) exists in some countries and very little in other countries. The question of how to provide the necessary infrastructure should be addressed, such as whether to establish a new infrastructure in a greenfield location or to locate a new plant where infrastructure exists.
- Environmental burdens caused by new plants in new locations may be regarded as undesirable.
- Unstable or unpredictable political regimes may be a deterrent to new investment.
- Even in more industrially developed countries in the region, low efficiency, low capacity utilization in existing plants, and slow administrative or governmental routines may cause delays.

4.5 These aspects of plant location are vitally important and must be carefully considered for each alternative technology in any given field location. Economies of scale will call for the largest possible conversion plant. The maximum size may be limited by technological constraints, such as the maximum capacity of single-train compressor packages, or of large high-pressure separators. The actual plant capacity may also be limited by possible market mechanisms, by financing limitations, and above all by feed gas limitations.

Typical Fields

4.6 The field information contained in Table A1.2 in Annex 1 is summarized in Table 4.1. Most fields are less than 1 tcf in size. Although 0.25–2.0 tcf fields considered in this study are small by international standards, the upper half of the range is sufficient to support a number of standard world-scale production plants.

4.7 It is interesting to observe that for one of the fields listed in Table 4.1 (Alba, off Equatorial Guinea), construction of a methanol plant with a daily capacity of 2,500 t using gas was recently announced. The field reserves are sufficient to cover more than 25 years of methanol production. The simplified economic analysis carried out in this study estimates a gas value of $1.4/MMBtu even after adding 30 percent to the announced capex of $300 million for the project.

4.8 It should be noted, however, that the African gas fields described in Table 4.1 were not examined here with a view toward providing recommendations for their development in conjunction with specific technologies. Rather, they were studied primarily as test cases of reserves that, with further analysis, could be considered for commercialization using some of the technologies discussed. Thus, a key point is that similar fields around the world could be subjected to examination under the same criteria for size, location, proximity to market, and gas value as a way of getting a good first approximation of their commercial potential.

Table 4.1 Typical Gas Fields Identified for the Study

Country	*Field*	*Onshore or offshore*	*Bcf proven*	*Distance (km)*	*AG or free gas*	*Flow rate (MM scm/d)*	*Production cost ($/MMBtu)*
Mozambique	Pande	On	2,700	900-PWV	free	8.5	0.35
Tanzania	Songo	On-off	1,200	230-Dar es Salaam	free	2.4	0.81
Côte d'Ivoire	Lion	Off	360	15 off; 90-Abidjan	AG	2.4	—
RSA	F-A Moss	Off	800	85-Mossel Bay	AG	1.7	—
RSA	Pletmos	Off	500	62-Plettenberg Bay	AG	1.0	—
RSA	E-M Mossel Bay	Off	400	363-Port Elizabeth	AG	—	—
Tanzania	Mnazi	Off	600	40-Mtwara	free	0.3	—
Gabon	Rabi-K	On-jungle	350	75-refinery	AG	0.3	—
Gabon	Grondin	Off	125	75-Port Gentil	AG	0.3	—
Equatorial Guinea	Alba	Off	850	32-Malabo	AG	2.6	—
Cameroon	Itindi	Off	70	45-Rio del Rey	AG	—	—
Cameroon	Ekoundo	Off	350	33-Ifiari	AG	—	—

— Not available.

Note: AG = associated gas; PWV = Pretoria, Witwatersrand, and Vereeniging, in RSA; RSA = Republic of South Africa; scm = standard cubic meters.

5

Plant Manufacturers

5.1 In conducting its review of different technologies, the study team visited several of the world's leading plant manufacturers and licensers, and contacted others by telephone. The main suppliers for each type of technology are listed in Table 5.1, in alphabetical order.

Table 5.1 Suppliers of Proven and Innovative Technologies for Commercializing Marginal Natural Gas Fields

Technology	*Supplier*
Methanol, including FPSO	Aker, Kellogg, ICI Katalco, Linde, Lurgi, Solco, Topsøe, Uhde
Ammonia and urea	Kellogg, Norsk Hydro, Linde, Lurgi, Topsøe, Uhde
Synthetic fuels, including FPSO	BP, Exxon, Rentech, Sasol, Shell, Statoil, Syntroleum, Topsøe
Dimethyl-ether	Topsøe, Amoco
Methanol-to-olefins (MTO)	Norsk Hydro, UOP, Mobil
Gas-to-olefins (GTO)	Norsk Hydro, UOP, Mobil
Iron reduction (DRI)	GRI, Kolbeinsen, Lurgi, Voest
Carbon black	Kværner
Combined carbon black, iron carbide, and electric power	Steel manufacturers
Bioproteins	Statoil

Annex 1. Data on Typical Gas Fields

Figure A1.1 Number and Size of Small Gas Fields in Western and Southern Africa

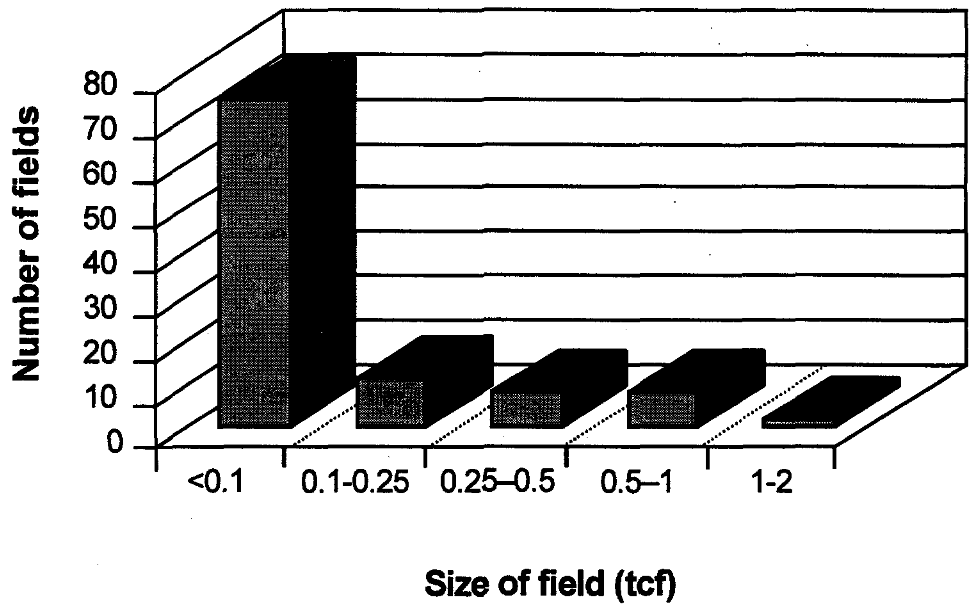


Table A1.1 Number of Production Plants Supported by Gas Fields of Different Sizes

	25-year gas consumption of small/medium/large plants in tcf	*Number of plants by field size in tcf*			
Plant type		*0.25*	*0.5*	*1.0*	*2.0*
Methanol onshore	0.160/0.4/0.625	1 small	1 medium	1 big, 1 med.	3 big
Methanol offshore	0.16/0.25/0.41	1 small	1 big	2 big, 1 small	5 big
Ammonia	0.28/0.51		1	2	4
Iron reduction	0.3	1	2	3	6
Synthetic fuel	0.43/0.85/1.7	0	0	1 small	1 big
Dimethyl ether	0.62/1.5	0	0	1	3
Carbon black	0.06	4	8	16	32
Gas-to-olefins	1.4/1.9/2.8	0	0	0	1
Synthetic fuels	0.85/1.7	0	0	1 small	1 big
Ammonia and urea	0.33/0.59	0	1	2	4
Syncrude	0.43/0.85	0	0	1	2

Table A1.2 Characteristics of Selected Fields

Field name	*Status*	*Location*	*Reserves (tcf)* [a]	*Distance to main market (km)*	*Free gas*	*AG*	*Flow rate (MM ncm/d)*	*Prod. cost ($/ MMBtu)*
Pande, Mozambique	Appraised small production]	Onshore	2.7	900 to PWV	x		8.5 (PC1.0)	0.35
Songo Songo, Tanzania	Appraised	Off-onshore	1.2–2.3	230 to Dar es Salaam	x		2.4–6.0	0.81
Lion, Côte d'Ivoire	Producing	15 km offshore	0.36	15+90 km to Abidjan		x	2.4 [b]	—
F-A Mossel Bay, RSA	Producing	85 km S of Mossel Bay RSA	0.8	85 km to Mossel Bay refinery		x	1.7 [b]	—
Pletmos GA A1, RSA	Appraised	62 km offshore	0.5	62 km to Plettenberg Bay		x	1.0	—
E-M Mossel Bay, RSA		47 km offshore	0.4	363 km to Port Elizabeth		x	—	—
Mnazi Bay, Tanzania	Not fully appraised	Offshore	0.6	40 km to Mtwara			0.3	—
Rabi-Kuanga, Gabon	Producing oil only	Onshore-jungle	0.35	75 km to Gamba refinery, 70 km to Oumbe City		x	0.3	—
Grondin, Gabon	Producing oil only	Offshore	0.125	75 km to Port Gentil		x	0.3	—
Alba, Equatorial Guinea	Producing condensates[c]	Offshore	0.85	32 km to Malabo		x	2.6	—
Itindi, Cameroon	Producing oil only	Offshore	0.07	45 km to Rio del Rey		x	—	—
Ekoundo Sud, Cameroon	Producing	Offshore	0.35	33 km to Ifiari		x	—	—

— Not available.

a. Proven or proven and probable.

b. Total flow rates from 10 wells, agreed delivery of 50 MMscf/d to power station in Abidjan (maximum pipe size 90 MMcf/d).

c. The field is planned to produce 2,400 bbl LPG/d based on 104 MMscf/d.

Note: AG = associated gas; PWV = Pretoria, Witwatersrand, and Vereeniging, in RSA; RSA = Republic of South Africa.

Annex 2. Synthesis Gas Processes

One-Step Steam Reforming

A2.1 One-step steam reforming is an old and well-proven process. It consists of a large furnace containing hundreds of high-alloy tubes filled with a nickel-based catalyst. Preheated gas and water vapor is fed into the catalyst tubes at about 800°C. The furnace is fired externally by many burners at the furnace wall or roof. The unit is bulky, and the process is expensive—the syngas section accounts for more than 50 percent of the total cost of a methanol plant. This process is recommended for methanol capacities up to 1,500 t/d.

Two-Step Combined Reforming

A2.2 In two-step combined reforming, the steam reformer is much smaller, but is followed by a secondary reformer to which partially converted gas from the primary reformer is fed, as well as oxygen from an air fractionating plant. The temperature in the secondary reformer exceeds 1,000°C, and much care is taken to obtain maximum recovery of the heat from the secondary reformer exit gas. A world-scale methanol plant using the process licensed by Topsøe was brought on stream by Statoil in western Norway in mid-1997. This process is recommended for methanol capacities between 1,500 and 3,500 t/d.

One-Step Auto-Thermal Reforming

A2.3 One-step auto-thermal reforming (ATR) is a large, highly efficient unit. There is no external firing, and all the heat required by the reforming process is produced by the combustion of gas and oxygen at the top of the ATR unit. It is expensive, particularly because of the need for an air fractionating plant. The cost of such a plant is very high, even for a small plant, but economies of scale make the ATR the most cost-effective syngas generator for very large plant sizes. This process is expected to be preferred for methane capacity greater than 3,500 t/d.

Two-Step Heat Exchange Reforming

A2.4 Two-step heat exchange reforming is a novel concept developed by several of the leading syngas licensers: ICI Katalco, Kellogg, Linde, and Topsøe. It is a variation on the combined reforming process mentioned above. Very hot gas exiting the secondary (oxygen blown) reformer is directed back to the primary reformer and used in lieu of external firing to heat the catalyst tubes. The overall plant is more energy efficient and much more compact, and is expected to be suitable for use in floating processing plants.

The recommended size range for this system is not precisely known, but would probably be large.

One-Step Convective Reforming

A2.5 One-step convective reforming is a novel process that was originally intended for hydrogen production. The process was developed by Haldor Topsøe and involves extensive integration of process heat. No oxygen is needed, and the process is offered in small units limited (so far) to syngas production corresponding to 250 t/d methanol. The units are small—only 2–3 meters in diameter—and several of them may be arranged in parallel with interconnecting manifolds. This process is believed to be particularly suitable for floating methanol plants. BP has recently announced a new compact syngas reformer suitable, inter alia, for small synfuel plants.

Metallurgical Problems

A2.6 There are inherent problems with metallurgy in process units operating at high temperatures as is found in reformers: the oxygen-fed gas burner in the secondary reformer, in particular, is subjected to very high temperatures. Metal dusting occurs for certain combinations of temperature, pressure, and carbon monoxide (CO) content, and may lead to deterioration of pipings or containers that come in contact with flowing gas. Metal dusting is now well understood, but it is important to be aware of this potential danger.

Oxygen and Ionic Membranes

A2.7 Oxygen for oxygen blown reformers is very expensive, and efforts are being made to find alternatives to costly air separation. One of the most attractive solutions at present is to use ionic membranes, that is, a process whereby oxygen ions, highly reactive, leak through the membrane and react with natural gas to produce CO and hydrogen on the other side. The technique for large-scale plants is still probably several years into the future, but successful development of ionic membranes will have a dramatic impact on the efficiency and economics of oxygen blown reforming plants.

Licensers

A2.8 Major licensers for syngas processes include the following:

- M.W. Kellogg.
- Haldor Topsøe A/S.
- Lurgi AG.
- Uhde GmbH.
- Linde AG.

- Toyo Engineering Company.

Annex 3. Advantages and Disadvantages of Floating, Production, Storage, and Off-Loading and "Packaged Projects"

Advantages of a Floating, Production, Storage, and Off-Loading Project

A3.1 The basic field development concept is a floating, production, storage, and off-loading (FPSO) project, producing oil from subsea wells or from a nearby wellhead platform. The associated gas released during the oil production must be disposed of in an environmentally sound and profitable manner. Options for the associated gas include transportation by pipeline to the shore, reinjection into the reservoir, and conversion to methanol or syncrude, and liquefied natural gas (LNG).

A3.2 Generally the field operator wants to produce primarily oil, because oil is the principal revenue earner, representing more than 90 percent of the total field revenue, depending on the gas content of the oil. Therefore, the installation is set up primarily for oil production, whereas profits from gas are marginal, if any, and gas is frequently seen as a problem rather than a resource.

A3.3 If the gas conversion plant is regarded as an incremental investment on the FPSO, the major portion of the cost of the infrastructure, all utilities, and the deck space is then charged to the oil production where these items would be needed even if the gas were to be flared. Charging 50 percent of the infrastructure cost to the oil production would reduce the methanol capital cost by some 15 percent as a result of not having to account fully for the offsite portion of the capex as in the case of a land-based plant.

A3.4 A second advantage of a floating plant is that the entire plant can be built and even commissioned at an established shipyard or fabrication yard and towed to its location without the need for large, local construction sites. A third advantage is mobility; the plant can be moved from one field to another, and can be moved off location in case of political disturbances. A final and significant advantage for combined oil production and gas conversion is that the associated gas represents a constraint rather than a resource for the oil field operator. For this reason, the onboard associated gas could be priced very low (for example, \$0.50/MMBtu) or could even be free of charge. In theory, and possibly in practice, the associated gas could have a negative value, viz., the conversion plant would charge the oil plant a fee for undertaking the disposal of the gas in an environmentally acceptable manner. This is particularly so if gas flaring is the only alternative, and there is a penalty for the carbon dioxide (CO_2) discharged by the flaring. As an example, it may be mentioned that such a CO_2 penalty is imposed by the authorities in Norway and corresponds to about $3.30 per MMBtu of natural gas flared.

A3.5 Methanol, synfuel, and syncrude production are potentially viable on a floating plant. The footprint area of a ship-mounted 1,000 t/d methanol plant is about 75 × 40 m or 3,000 m^2, and a similar footprint area is applicable for synfuel or syncrude production. None of the other processes evaluated are considered viable for FPSO because of their size and complexity: ammonia, urea, dimethyl ether (DME), methanol-to-olefins (MTO), gas-to-olefins (GTO), direct reduction (DR), and carbon black.

A3.6 A version of FPSO could be the so-called beached barge whereby the conversion plant is built on a simple barge made of steel or concrete with adequate space and storage capacity. It is built in an established shipyard and towed to its location, thereby eliminating the need for setting up a large, temporary construction camp. The barge is placed to rest on the sea bed in very shallow water, skidded onto the beach, or simply anchored to a land-fixed jetty.

Disadvantages of FPSO

A3.7 Among the disadvantages of such floating conversion plants of the offshore type is the sensitivity of offshore operations to sea motion, where separators, distillation columns, and possibly the tubular steam reformers might suffer reduced on-stream time on account of bad weather. This effect may be mitigated by replacing steam reformers with convective reformers, by using structured packing in distillation columns, or by shipping undistilled, crude methanol (purity of about 80 percent) to the shore. A large market for crude methanol is DME, MTO, or GTO plants, where it is used as a feedstock.

A3.8 A second disadvantage of the FPSO concept for methanol production is that oxygen-blown synthesis gas processes are undesirable because of the inherent safety risks involved in installing an oxygen plant on an FPSO. This could be avoided by using a steam reformer or a novel compact reformer without the use of oxygen licensed by Topsøe and BP.

Packaged Projects

A3.9 The individual technologies presented here are discussed primarily on a stand-alone basis without much reference to any integration effects. The advantages of "packaged projects," however, should be given due consideration when evaluating gas utilization options for Africa. A stand-alone plant must develop its own complete infrastructure: harbor, roads, site preparation, buildings, offices, power plant, water treatment plant, and administration. The advantage of sharing these infrastructure costs among several production units is obvious, although the gas consumption of the combined plant may exceed the supply of gas in the case of smaller fields. This issue should perhaps be examined further in a separate study. Some examples are given below.

Ammonia followed by Urea or Ammonium Nitrate

A3.10 Ammonia is difficult to handle and costly to store and transport. Since a large proportion of the world's ammonia is used in the production of urea as well as mixed fertilizers, it is usually more economic to convert the anhydrous ammonia to these products within the same industrial complex. Ammonia and CO_2 discharged from the ammonia process are converted to urea, a white powder or granulate used for fertilizers or as a feedstock for other chemicals. To make ammonium nitrate, ammonia is first converted to nitric acid. With the addition of more ammonia, ammonium nitrate is formed, which can be stored and transported more easily, to be used in the manufacture of fertilizers and explosives.

Ammonia and Methanol

A3.11 There are advantages in having ammonia and methanol plants at the same location, since they can share a number of common facilities, provided that market projections for these two products favor the decision to invest simultaneously in the two processes. The ammonia process discharges CO_2, and adding a small portion of CO_2 to the methanol feed gas often has clear process advantages.

Methanol, Olefins, and Polyolefins

A3.12 The methanol-to-olefins (MTO) process produces a mixture of ethylene, propylene, butenes, and higher hydrocarbons from crude methanol. These products are feedstocks for polyethylene, polypropylene, and polyvinyl chloride (PVC) or other vinyl products. While methanol can be easily stored and transported, this is not the case with light olefins, which are gaseous. The MTO plant should therefore be located adjacent to a polyolefin plant. Depending on local conditions, an obvious option would be to convert the gas to olefins at one plant site, rather than first produce methanol, then ship it to a different site, convert methanol to olefins at the second site, and finally convert olefins to polyolefins.

A3.13 Another possibility is the installation of a methanol plant located within a refinery with a catalytic cracker. Methyl tertiary butyl ether (MTBE) could be produced on site by reacting isobutylene supplied by the cracker with methanol. The MTBE could be sold or blended into gasoline by the refiner.

Carbon Black, Iron Carbide, and Gas-Fired Power Plant

A3.14 This combination plant is treated separately in Annex 11.

Liquefied Petroleum Gas or Condensate

A3.15 In projects consuming natural gas, one could consider extracting and isolating the condensate or liquefied petroleum gas (LPG), if the gas is not very lean. LPG can be sold on the world market or used as a feedstock for the local petrochemical industry.

Annex 4. Methanol

A4.1 The evaluation of methanol synthesis is explained in greater detail than other processes to demonstrate the methodology employed for the evaluation of all the technologies.

Sources: Kellogg, Linde, Lurgi, Uhde, and Topsøe.

Concept

A4.2 The objective is to convert natural gas to methanol, fuel or chemical grade, using the appropriate process from among several options—the best option being dependent on the plant capacity.

Product Characteristics

State at room temperature and ambient pressure	Liquid
Properties	Colorless, toxic, inflammable
Chemical structure	CH_3OH
Molecular weight	32.04
Density in kilograms per liter	0.79
Boiling point	64.7°C
Heat of combustion	22,662 kJ/kg

Product Market

A4.3 World production of methanol in 1997 is estimated at 29.1 million t. The estimate for total African output is 0.8 million t. Libya and Algeria represent 95 percent of the African production capacity. South Africa, which produces 46,000 t a year, also imports 40,000 t annually.

A4.4 Some 70 percent of world methanol production is used in chemical synthesis, particularly in the form of formaldehyde (40 percent), MTBE (used as a high octane blending component in gasoline) and acetic acid. Methanol is also used as an energy source, although high costs and other factors have inhibited market growth. In general, methanol is used to produce chemicals whose end use is seasonal and varies according to the world economic activity level. More precisely, methanol use in 1996 consisted of the following:

Formaldehyde:	34.9%
Acetic acid:	6.7%
MTBE and fuels:	30.1%
Others:	28.3%

A4.5 Previously, companies that consumed methanol as a feedstock in their production processes manufactured it themselves. During the 1980s, the number of plants producing methanol at remote sites exclusively for sale to processors increased dramatically, and methanol became a world commodity. African methanol production units will not have any particular competitive edge in this market. Even the smallest of factories could satisfy the South African consumption of 80,000 t/y with less than half a year's output, so that the remaining production capacity would have to compete at world market prices.

A4.6 The SADC Gas Utilization Study makes similar assessments for Angola and Namibia. In Namibia, a 2,000 t/d production facility could be profitable at Walvis Bay given there is local demand. There is only a limited local market for methanol, unless a methanol consuming industry is established. In the absence of local markets, methanol synthesis was not considered a viable option for the use of natural gas in those two African countries.

A4.7 Recently, Atlantic Methanol Production Company has contracted Raytheon to build a 2,500 t/d grassroots methanol plant on Bioko Island, off of Equatorial Guinea. Gas feed for the plant will come from Alba field. Raytheon expects to complete the plant, including a desalinization unit for seawater and an electric power generation system, by the end of 2000.

A4.8 World market methanol prices have historically varied from $120 to $180/t. In June 1997, the price was $200. The price was well over $500/t for several months in 1995. Intercontinental shipping charges for methanol are dependent upon general rate levels, parcel sizes and the season. Typically, intercontinental shipping rates range between $30 and $50/t of methanol.

A4.9 The inherent cyclical nature of the demand for methanol end products, the introduction of methanol as a world commodity and varying shipping charges result in frequent, large methanol price fluctuations. This makes it difficult to forecast prices reliably and increases the financial risks of new methanol projects.

Typical Plant Size

A4.10 Economies of scale result in current "world-scale" plant sizes on the order of 2,000–2,500 t/d. Many older plants have capacities of 1,000 t/d or even less. The economies of scale have placed upward pressure on plant capacity, even if low feed gas prices are assumed in the case of gas in remote locations (for example, \$0.50/MMBtu). Future land-based plant sizes may be as high as 10,000 t/d.

A4.11 The optimal capacity for a given plant to be built is determined not only by plant construction costs, but also by the available feed gas rate, the gas price and the market and price forecasts for methanol.

Process

A4.12 The methanol process comprises three main stages:

- desulfurization and syngas production
- compression and methanol synthesis
- purification of final product.

Syngas production is discussed in general in Annex 2. The main catalytic process is an endothermic reaction of water and natural gas over a nickel-based catalyst at a temperature of about 800°C and a pressure of about 30 bar, higher for large-scale processes.

A4.13 The main difference between existing and novel processes is the heat transfer technology used in the syngas production (steam reforming, combined reforming, heat exchange reforming, autothermal reforming and convective reforming). The choice of process is determined by the plant size.

A4.14 An important difference among the syngas processes is whether they are "oxygen blown," that is, whether oxygen is injected into the secondary reformer system. Oxygen injection decreases the plant size, increases efficiency, reduces undesirable discharges and improves process control. An air separation plant is very expensive, however, and economic only for plant sizes well above 1,500 t/d.

A4.15 The anticipated large methanol market as a feedstock for DME and MTO processes requiring crude methanol could increase the size of world-scale methanol plants to 4,000 t/d or even 10,000 t/d. For such a size range, very large, single stage, oxygen blown autothermal reformers (ATR) would be most cost effective. An additional advantage of the ATR is that a typical plant pressure of 60–100 bar eliminates or substantially reduces the costly compression of syngas to 70–80 bar required in the methanol synthesis.

A4.16 The objective of any technical improvements is to reduce plant cost, feed gas consumption, and environmentally harmful discharges (CO_2 and oxides of nitrogen, NO_x).

A4.17 Syngas is a mixture of hydrogen (H_2) and carbon monoxide (CO). The stoichiometric ratio of H_2 to CO required for methanol synthesis is 2:1. The ratio of H_2 to CO produced from natural gas can be fully controlled by those processes using oxygen in reforming. Steam reforming does not always give the desired ratio (depending on feedstock composition), and the syngas composition in the methanol synthesis loop is controlled by purging a slip stream into the fuel system. The cost of the syngas section of a complete methanol plant accounts for 50–60 percent of the total plant cost.

A4.18 Crude methanol (purity of about 80 percent) leaving the synthesis plant must be distilled to well over 99 percent purity in several large distillation columns.

Feedstock

A4.19 Practically all methanol today is made from natural gas, but heavier hydrocarbons, such as naphtha as well as coal, are also possible feedstocks. The gas must be free of sulfur which would poison the catalysts, but otherwise the process is flexible with regard to the hydrocarbon composition of the feed gas. Efficient methanol plants consume about 30 GJ per metric ton of methanol, or 30,000 scf of methane per metric ton. This study uses a conservative figure of 32,000 scf/t.

Licensers

A4.20 Major licensers for methanol processes include

- Haldor Topsøe A/S.
- ICI Katalco.
- Lurgi AG.
- Kellogg.
- UHDE GmbH.
- Linde AG.

Innovative Developments

A4.21 Extensive development is ongoing with a view to making syngas production, which is needed for the majority of the technologies described in this report, less bulky, more cost efficient, more energy efficient and with a reduced discharge to the environment. All licensers listed above are actively engaged in this development.

Topsøe Convection Reformer (TCR)

A4.22 This novel reformer design may be worthy of special mention. It uses only convection for heating the reformer catalyst, and has an innovative way of arranging heat transfer in the reactor. TCR has been successfully tested in a pilot plant for 2,000 hours, and is much more compact then other reformers. The largest size offered at present is for a capacity of 250 t/d. For a 1,500 t/d plant, six such modules will be installed in parallel. The process requires no oxygen, and the exit temperature is only about 600°C. The process should be very well suited for offshore use on an FPSO.

Ionic Membranes

A4.23 There is an important development going on which, if successful, could have a significant effect on the size and cost of future syngas production plants. Ionic membranes are a novel type of membranes that allow only oxygen ions to pass through the pores. The use of such membranes would eliminate the need for very expensive air fractionating plants used in most syngas processes (combined reforming, heat exchange reforming and autothermal reforming), thereby allowing for considerable cost savings. It may still take several years before such a technology may be regarded as proven. Air Products was recently awarded a $84 million research program contract in this field by the U.S. Department of Energy. The new membrane under development is a wafer-thin rare-earth oxide ceramic sheet through which air is passed. Air Products told the Oil & Gas Journal (O&G J., 28 July 1997, p. 35) that this technology could reduce the cost of syngas production by a minimum of 30 percent and possibly as much as 50 percent.

Additional Methanol Market

A4.24 Innovative development affecting the methanol market could be the successful development of large-scale DME, MTO or GTO processes (see Annexes 7 and 8). Low cost, crude methanol from very large plants would be required for these processes.

Investment Cost

A4.25 The actual capital cost of a methanol plant is affected by many factors, including the feedstock composition, the specified product quality, the existing infrastructure, local conditions, labor cost and availability, local laws and regulations, and not least, the plant capacity. A detailed cost estimate for several plant sizes at a given location is beyond the scope of this study. The basis for the estimate given below is the cost of a world-scale plant (2,500 t/d of chemical grade methanol, inside battery limits, U.S. Gulf Coast basis). At present this estimate is $200 million. Fifty percent is added to include strictly necessary offsites: investments for the supply of electric power, process water, boiler feed water, cooling water and other utilities, as well as roads and buildings within the plant fence. No local infrastructure outside the plant fence is included. On this basis, the capex of a 2,500 t/d methanol plant is taken as $300 million. The result of the calculation based on the investment cost in the U.S. Gulf Coast is referred to as the "base case." In reality, with the exception of very unusual situations where there is well developed infrastructure for chemical/petrochemical/petroleum industry construction, the investment cost will be higher by 30–100 percent. The localization factor is defined in this study as a number by which the U.S. Gulf Coast capex figure should be multiplied to obtain the capex used in economic calculations; it reflects the cost of transporting equipment to the site, local cost and efficiency of labor, management and public services. In most examples, localization factors of 1.3, 1.5, 1.75 and 2.0 are examined. The base case may also be regarded as one in which there is a reduction in capex of 30 percent at a localization factor of 1.3.

Areal Requirement

A4.26 A 2,500 t/d methanol plant, battery limits, could have a minimal footprint area of 9,000 m^2. Adding 50 percent to include offsites, the area requirement is close to 15,000 m^2 which does not include all areas and infrastructure outside the process area proper. The "offsites" depend on the system distribution defined in each separate contract, but are taken here to include roads, foundations and buildings inside the plant fence, including offices, laboratories, control room, workshop and storage, and process systems to handle cooling water, boiler feed water and electric power. The offsites do not include any infrastructure not specifically related to the plant production.

Staffing Requirement

A4.27 The staffing requirement depends on local conditions and availability of trained personnel. A world-scale plant (2,500 t/d) could be served by a payroll of about 100 people.

Sample Calculation of Gas Value for a 1,500 t/d Onshore Methanol Plant

A4.28 The gas value or market value of gas is a key indicator of the viability of a gas project. It is defined as the maximum gas price that can be charged at the burner tip for different gas uses and still maintain market competitiveness of the project. In order to calculate the gas value in methanol production, the world market price of methanol in both main international markets and Africa needs to be estimated. Depending on whether the product will be exported or will compete with imports, either export-parity or import-parity pricing should be used. The price thus selected is then used to estimate the total sale revenue in each case considered as illustrated below for a 1,500 t/d onshore plant.

A4.29 The sale prices of most products investigated in this study have fluctuated considerably during recent years. World demand for most products has increased by 2–3 percent annually, but when a new world-scale production unit comes on stream, overcapacity quite often results and prices fall. Prices begin to increase again when demand begins to match supply. The price of methanol has varied between \$120/t and \$180/t. The sale prices used in the calculations are also dependent on where the product is sold. If a region imports the product in larger amounts than the capacity of the proposed plant, it is reasonable to assume that the new production will substitute imports, and the cost, insurance, and freight (CIF) price for the region should be used. If the product has to be exported, the export-parity price, that is, the current world market price less transport costs to the destination, should be used. The transportation costs vary with origin and destination and type or volume of product to be transported. For most products the costs from Africa to main destinations overseas are in the range of \$30–50/t. An increase in the methanol price by 30 percent will increase the gas value from \$1.6/MMBtu to \$3.0/MMBtu, that is, by nearly 90 percent. For this study an average of recent world prices, $145/t of methanol, has been used in the calculations.

A4.30 The gas value is arrived at by establishing investment, operating and maintenance costs for the plant over a 3-year investment period and a subsequent 25-year operating period. In Table A4.1 the investment costs are inserted for the first three years in the cash flow column, and a net annual revenue is then calculated, which sets the net present value (NPV) equal to zero at a discount rate of interest of 15 percent.[4] In the example, an annual investment of $72 million during the first three years and a net annual income of $39 million for the subsequent 25 years give an NPV of about zero at a discount rate of 15 percent. That is to say, an annual investment of $72 million for 3 years will require a net annual income of $39 million over 25 years to give a 15 percent return on capital. In addition, the project has to pay $11 million for operation (including labor) and maintenance. Based on a gross annual revenue of $74 million at $145/t, the project can pay a maximum of $24.5 million annually for the gas, that is, $74 million - 38.5 million - 11 million = $24.5 million. The gas value is then found by dividing the total (maximum) gas cost, $24.5 million, by the annual gas consumption, 16.3 bcf, which gives a gas value of $1.6/MMBtu for a 1,500 t/d plant. The gas value for a 2,500 t/day is $2.1/MMBtu while that of a 600 t/d plant is $0.4/MMBtu. As shown in Table A4.4, a 1,500 t/d methanol plant mounted on an FPSO gives a higher gas value ($1.7/MMBtu) than an onshore one due to the lower investment costs (on account of 50 percent of the infrastructure being charged to the oil production).

A4.31 The gas value is sensitive to the discount rate of interest, product price, capital outlay and, to a lesser degree, operating and maintenance costs, which are more predictable. For the same capital expenditures, a discount rate of 15 percent clearly requires higher net incomes in subsequent years than, for example, a discount rate of 10 percent. At 10 percent the gas value for a 1,500 t/d plant will increase from $1.6 to $2.4/MMBtu, viz., by 50 percent. The investment costs are based on suppliers' data for battery limits (U.S. Gulf Coast basis) plus 50 percent for offsites. For a "greenfield" development in a developing country, a localization factor needs to be applied and could range between 1.3 and 2, thus increasing the investment costs by 30 percent to 100 percent. The gas value in the base case above would be reduced to $0.7/MMBtu for an increase in investment cost of 30 percent.

[4] The discount rate of interest is interpreted as the opportunity cost of capital, that is, the marginal productivity of additional investments in the best alternative uses.

Table A4.1 Calculation of Gas Value for Localization Factor of 1.0
Plant capacity 1,500 t/d, methanol price $145/t, gas consumption 16 bcf/y, discount rate 15%
Gas value (market value) = $1.6/MMBtu

Year	*Methanol production (t/y)*	*Revenue ($ million)*	*Capex ($ million)*	*Gas cost ($ million)*	*O&M cost (excluding gas) ($ million)*	*Cash flow ($ million)*
1		0	72			-72
2		0	72			-72
3		0	72			-72
4	510,000	74		24.5	11	38.5
5	510,000	74		24.5	11	38.5
6	510,000	74		24.5	11	38.5
7	510,000	74		24.5	11	38.5
8	510,000	74		24.5	11	38.5
9	510,000	74		24.5	11	38.5
10	510,000	74		24.5	11	38.5
11	510,000	74		24.5	11	38.5
12	510,000	74		24.5	11	38.5
13	510,000	74		24.5	11	38.5
14	510,000	74		24.5	11	38.5
15	510,000	74		24.5	11	38.5
16	510,000	74		24.5	11	38.5
17	510,000	74		24.5	11	38.5
18	510,000	74		24.5	11	38.5
19	510,000	74		24.5	11	38.5
20	510,000	74		24.5	11	38.5
21	510,000	74		24.5	11	38.5
22	510,000	74		24.5	11	38.5
23	510,000	74		24.5	11	38.5
24	510,000	74		24.5	11	38.5
25	510,000	74		24.5	11	38.5
26	510,000	74		24.5	11	38.5
27	510,000	74		24.5	11	38.5
28	510,000	74		24.5	11	38.5
NPV						0

Note: O&M = operating and maintenance.

A4.32 For each plant size, a sensitivity analysis has been carried out. Because the localization factor in remote locations is expected to vary between 1.3 and 2.0, the capex is typically varied by up to a factor of 2 in this study. The product price is also varied to examine its effect on the gas value. An illustrative example of sensitivity analysis is given for a 1,500 t/d onshore methanol plant in Table A4.2. Detailed calculations are not included in the report, but critical effects of such variations are discussed for each process considered. Processes for which the gas value exceeds $0.50/MMBtu are considered potentially viable.

Table A4.2 Sensitivity Analyses of a 1,500 t/d Onshore Methanol Plant

	Localization factor		
Price	*1.0*	*1.3*	*1.5*
+30%	3.0	2.1	1.6
$145/t	1.6	0.7	0.1
-30%	0.2	-0.7	-1.3

A4.33 The above calculations show how sensitive the gas value is to changes in capex and product price. Thus, the estimated gas value for each project should be taken as indicating the order-of-magnitude only. To obtain more accurate estimates, the economics should be examined further through an in-depth feasibility study for a given plant or location. However, since all the calculations follow the same methodology, the ranking of projects in order of decreasing gas value should not be affected markedly by changes in capex, operating and maintenance costs, although market risks would vary from technology to technology.

Key Results for Onshore Methanol Plants and Sensitivity Analysis

A4.34 The key results for onshore methanol plants ranging from 600 t/d to 2,500 t/d in size are shown in Table A4.3. Gas values are computed for five localization factors ranging from 1.0 to 2.0. In the base case (which is also equivalent to there being a 30 percent reduction in capex at a localization factor of 1.3), both 2,500 b/d and 1,500 b/d plants are commercially viable. At a localization factor of 1.3, the 1500 t/d plant is economic at the product price of $145/t, but cannot sustain even a 5 percent fall in product price. The 2,500 t/d plant can sustain a drop in product price of 15 percent, giving a gas value of $0.7/MMBtu, but if the product price falls by 20 percent, the gas value falls to $0.4/MMBtu. At a localization factor of 1.5, only the 2,500 b/d plant is economic. At a localization factor of 1.75, a product price increase of 5 percent, 25 percent, and 70 percent is needed to raise the gas value above $0.5/MMBtu for the 2,500 t/d, 1,500 t/d, and 600 t/d plants, respectively.

Table A4.3 Characteristics and Economic Analysis of Onshore Methanol Plants

Data item	*Unit*	*Large*	*Medium*	*Small*
Daily methanol capacity	t/d	2,500	1,500	600
Single unit annual capacity	t/y	850,000	510,000	204,000
Capex, including offsites	million $	300	220	120
Maintenance cost (3% of capex)	million $/y	9.0	6.5	3.6
Operating cost, excluding feed gas	million $/y	6.2	4.5	2.5
Feed gas consumption	billion scf/year	27	16	6.5
Construction period	years	3	3	3
Operating period	years	25	25	25
Sale price	$/t	145	145	145
Gas consumption, 25-year lifetime	tcf	0.68	0.41	0.16
Gas Values				
Localization factor 1.0 (base case)	$/MMBtu	2.1	1.6	0.4
Localization factor 1.3	$/MMBtu	1.4	0.7	-0.8
Localization factor 1.5	$/MMBtu	0.9	0.1	-1.6
Localization factor 1.75	$/MMBtu	0.3	-0.6	-2.6
Localization factor 2.0	$/MMBtu	-0.3	-1.3	-3.6

Potential for Offshore Versions: On Platforms or Floaters

A4.35 The idea of mounting a 1,000–1,500 t/d steam-reforming-based methanol plant on a ship or a barge has been proposed for many years, but none has as yet been built or contracted. One advantage is that the entire plant can be built and even commissioned at an established shipyard or fabrication yard and sailed to its location without the need for a large local construction site. Mobility is another great advantage of the floating plant. The footprint area of a ship-mounted 900 t/d plant is estimated to be about 75 m × 40 m or 3,000 m^2. This could be decreased by using the novel TCR by Topsøe.

A4.36 The total capital cost of a combined FPSO for production and stabilization of 60,000 b/d of oil, and production of 900 t/d of high grade methanol, was estimated in 1992 by Topsøe and Aker to be $423 million, including the vessel, but excluding the cost of the well development. Solco Trading, Stavanger, has proposed a floating methanol plant for 2,700 t/d methanol and 50,000 b/d crude with a North Sea-going vessel with capital expenditures of $500 million. ICI Katalco is in the process of developing an FPSO version for BHP Australia. The cost figures are not available. Aker/Ugland is developing a barge mounted 1,500 t/d methanol plant for a Southeast Asian location.

A4.37 Newer capex estimates, with more compact methanol processes, could be lower. These are based on conceptual engineering only and have not yet been commercialized. Much more compact novel syngas generation processes may open up greater opportunities for floating methanol plants.

A4.38 Similar data for medium-size methanol plants mounted on an FPSO are given in Table A4.4. These represent single-train methanol plants with production capacities of 1,500 t/d, 900t/d, and 600 t/d mounted on an FPSO where the oil and gas production-separation plant is also present. Fifty percent of the infrastructure and utilities for the methanol plant are charged to the oil plant, leaving the remaining 50 percent to be charged to the methanol plant. The rationale is that the FPSO is necessary for producing, stabilizing and off-loading the oil with or without the methanol plant. Hence, it would be reasonable to assume that the space and utilities required for the methanol plant will be only a marginal addition to the FPSO cost. The methanol production relieves the oil producer of having to reinject or flare the gas.

Sensitivity Analysis

A4.39 At localization factors of 1.3 and 1.5, only the 1,500 t/d plant can be considered economic at the product price of $145/t. At a localization factor of 1.5, a product price increase of 25 percent, and 35 percent would be required to raise the gas value above $0.5/MMBtu for the 900 t/d and 600 t/d methanol plants, respectively.

Constraints for African Methanol Plants

A4.40 Possible constraints on methanol plants in Sub-Saharan Africa include the following;

- Lack of infrastructure if installed in a new or remote location.
- Lack of trained labor and management.
- No local market for methanol except where it would be viable to establish a methanol-consuming industry, such as conversion of methanol to formaldehyde and formaldehyde-urea industrial adhesives, or methanol to MTBE.

Table A4.4 Characteristics and Economic Analysis of Medium Sized Methanol Plants on an FPSO

Data item	*Unit*	*Large*	*Medium*	*Small*
Daily methanol capacity	t/d	1,500	900	600
Single unit annual capacity	t/y	510,000	306,000	204,000
Capex, including offsites	million $	180	135	100
Maintenance cost (3% of capex)	million $/y	5.4	4.1	3.0
Operating cost, excluding feed gas	million $/y	9.4	6.8	5.2
Feed gas consumption	billion scf/year	16	9.8	6.5
Construction period	years	3	3	3
Operating period	years	25	25	25
Sale price	$/t	145	145	145
Gas consumption, 25-year lifetime	tcf	0.41	0.24	0.16
Gas Values				
Localization factor 1.0 (base case)	$/MMBtu	1.7	1.0	0.6
Localization factor 1.3	$/MMBtu	1.0	0.1	-0.5
Localization factor 1.5	$/MMBtu	0.5	-0.5	-1.1
Localization factor 1.75	$/MMBtu	-0.1	-1.3	-2.0
Localization factor 2.0	$/MMBtu	-0.7	-2.0	-2.8

Annex 5. Ammonia and Urea

Sources: Norsk Hydro, M.W. Kellogg, and Haldor Topsøe.

Concept

A5.1 The objective is to convert natural gas to ammonia, and possibly further to urea.

Product Characteristics

State at room temperature and ambient pressure	Gas
Properties	Colorless, toxic
Chemical formula	NH_3
Molecular weight	17
Density in kilograms per liter	0.77
Boiling point	-33.3°C

Market for Ammonia

A5.2 World production of ammonia in 1996 reached 95.7 million t. African production amounted to some 3.0 million t. During the period of droughts in the 1980s, African output stagnated at around 2.0 million t annually, but now the production trends are changing. Output in the southern African region is forecast to increase by 2 percent annually. This is expected to lead to a shortfall in the market some time between 1997 and 2010.

A5.3 Eighty-five percent of the ammonia produced is used for fertilizers, the most important one being urea. The remaining 15 percent of world ammonia output is used to make a variety of other products, including animal feeds, explosives, and polymers.

A5.4 Large-scale ammonia production is linked to the "green revolution"; increasing use of fertilizers created an industrial market for ammonia. Demand for nitrogen products is now stagnating in the industrial world. There is increasing consumption in developing countries, following the introduction of novel agricultural technology. Ammonia is an international commodity, although only 10 percent of world output is traded.

A5.5 In southern Africa, there are ammonia plants in Botswana, Republic of South Africa (RSA), Zambia, and Zimbabwe, mainly for the manufacture of fertilizers (RSA and Zambia also produce mining explosives from their ammonia). These plants run on antiquated techniques or rely on electricity for processing and experience competition from imported ammonia. The South African Sasol plants are the exception, using relatively modern technology and relying on gas. Some 100,000 t are imported to southern Africa today, and this figure is expected to increase to 200,000 t within 10–15 years.

A5.6 The SADC Gas Utilization Study recommended that, given the market characteristics of ammonia, the southern African countries reevaluate the manufacturing and sale of ammonia. Both the Modderfontein plant (using coal) and alternative greenfield coastal sites are seen as potentially attractive projects. The establishment of a world-scale plant with an annual output of 600,000 t would entail the construction of terminals and export facilities.

A5.7 World market prices for ammonia have varied between \$100 and \$230/t over the last five years. The 1997 price level of \$220/t is expected to hold in the near future, but long run estimates indicate price levels and fluctuations similar to those of the past five years. Prices are seasonal, depending on agricultural activity and fertilizer demand.

A5.8 Intercontinental shipping rates for the transportation of ammonia are quoted at around \$35/t. Very small parcel rates to southern Africa may run as high as \$100/t. Such rates favor the production of urea at a local plant, urea being simpler and less expensive to transport than ammonia.

Plant Size

A5.9 Plant capacities vary over a wide range, but most plants in operation are in the capacity range of 1,000–2,000 t/d. Economies of scale have exerted steady upward pressure on one-train capacity. The footprint area for a typical 1,800 t/d plant could be about 50 m × 200 m = 10,000 m^2.

Ammonia Process

A5.10 Nearly all the world's production of ammonia is based on natural gas as the feedstock, using the well-known and well-proven process described below, characterized by the syngas being produced by a primary tubular steam reformer, followed by an air-blown secondary reformer. Annex 2 provides a general discussion on syngas production. After feedstock treatment (removal of sulfur and chlorides), natural gas is compressed to reformer pressure, if necessary, and preheated.

A5.11 Treated gas is directed to the primary reformer where the purpose is to convert the bulk of the hydrocarbon feed to H_2 and CO by reaction with steam. The remainder of this reaction is carried out in the secondary reformer with the heat supplied by air which is introduced to burn part of the gas. The air also supplies nitrogen required for the synthesis. After the secondary reformer the gas, which at this point is a mixture of hydrogen, carbon dioxide (CO_2), carbon monoxide (CO), nitrogen (N_2), and unreacted natural gas, is directed to a two-stage shift converter for the conversion of CO with water to CO_2 and hydrogen.

A5.12 After CO_2 removal in an absorber and regenerator system, the gas still contains small amounts of CO and CO_2, which have to be removed before the ammonia synthesis. Their removal is effected in the methanation step, which is the reverse of the reformer reaction, converting CO and CO_2 to methane (CH_4) and water (H_2O). The gas leaving the methanation step has the required 3-to-1 ratio of hydrogen to nitrogen (H_2:N_2) for the ammonia synthesis. Ammonia synthesis can be carried out over a wide range of pressure, between 100 and 800 bar, depending on the process. Conversion per pass in the synthesis loop increases with pressure, thereby reducing equipment size, but it has to be weighed against increased design complexity. New plants typically operate between 250 and 350 bar. Reciprocal electric driven compressors are used for small plants with capacities up to 600 t/d, while steam turbine driven centrifugal compressors are used in the great majority of new plants having capacities of 800–2,000 t/d in one train. The tendency has been to increase the capacity per train to take advantage of economies of scale. The ammonia produced in the converter is cooled, condensed, and directed to a separator. The degree of cooling required depends on the pressure. At high pressures much of the ammonia can be condensed at temperatures obtainable by water cooling. At lower pressures and higher (>30°C) cooling water temperature, there is increased reliance on refrigeration to provide additional cooling. After condensation of ammonia the remaining gas is recirculated to the converter. Liquid ammonia collected in the separator is directed to a flash drum where the pressure is reduced to approximately 16 bar. Flash gas from the drum is directed to an ammonia recovery section.

A5.13 Some of the circulating gas has to be purged to avoid a build-up of inerts, consisting mainly of argon and methane. The purge gas components can be separated cryogenically after ammonia recovery and the argon can be collected and sold separately. The remaining gas can be returned to the reformer section. Another possibility is to direct the purge gas to a conversion unit, which is a second ammonia synthesis loop.

Feedstock

A5.14 Natural gas with CO_2 and H_2S removed is the principal feedstock and accounts for more than 80 percent of the world's ammonia production. The term "natural gas" in this connection usually refers to the fraction that contains mostly methane with small percentages of ethane and higher hydrocarbons. A wide variety of other hydrocarbons can also be used as a feedstock, that is, naphtha and LPG. The design of an ammonia plant is heavily dependent on the feedstock composition and is custom-engineered accordingly.

A5.15 High-efficiency plants use about 33 GJ/t, corresponding to about 1,000 m^3 of dry natural gas per metric ton ammonia produced. While the specific energy consumption for current ammonia plants is on the order of 33 GJ per metric ton of product, one of the expected results of the improvements listed below is to bring this figure down to 30–31 GJ/t.

Licensers of Ammonia

A5.16 Major licensers of ammonia plants include the following:

- Haldor Topsøe A/S.
- Kellogg.
- Toyo Engineering Company.
- Uhde GmbH, Dortmund.

Innovative Developments

A5.17 There have been several significant improvements in the process, and others are under development. They include the following:

- Novel heat exchange methods in the reformer section.
- Prereforming hydrocarbons heavier than methane to methane upstream of the primary reformer.
- Novel shapes of the nickel-based reformer catalysts.
- Introduction of the "Reformer Exchanger."
- New ruthenium-based ammonia synthesis catalysts with significantly improved product yields.
- New arrangement of catalyst beds in the ammonia synthesis converters.

Investment Cost

A5.18 Based on information received from major ammonia licensers, it may be stated that ammonia plants using current technology would require a battery limit capital investment, including offsites, on the U.S. Gulf Coast basis, as follows:

1,000 t/d	$190 million
1,800 t/d	$280 million

Key Results for Ammonia and Sensitivity Analysis

A5.19 The key results for ammonia plants are shown in Table A5.1 below. Both plants are economic at the capex based on the U.S. Gulf Coast. At a localization factor of 1.3, a 15 percent product price increase would be required to raise the gas value of the 1,000 t/d plant above $0.5/MMBtu. At a localization factor of 1.5, the product price would need to increase by 5 percent and 30 percent, respectively, for the 1,800 t/d and 1,000 t/d plants to raise the gas value above \$0.5/MMBtu. The corresponding figures at a localization factor of 1.75 are 20 percent and 45 percent, respectively.

Table A5.1 Characteristics and Economic Analysis of Ammonia Plants

Data item	*Unit*	*Large*	*Medium*
Single unit daily capacity	t/d	1,800	1,000
Single unit annual capacity	t/y	612,000	340,000
Capex, including offsites	million \$	280	190
Maintenance cost (3% of capex)	million \$/y	8.4	5.7
Operating cost, excluding feed gas	million \$/y	8.0	5.5
Feed gas consumption	billion scf/year	20	11
Construction period	years	3	3
Operating period	years	25	25
Sale price for ammonia	\$/t	165	165
Gas consumption, 25-year lifetime	tcf	0.51	0.28
Gas Values			
Localization factor 1.0 (base case)	\$/MMBtu	1.8	1.0
Localization factor 1.3	\$/MMBtu	0.9	-0.1
Localization factor 1.5	\$/MMBtu	0.3	-0.9
Localization factor 1.75	\$/MMBtu	-0.5	-1.8
Localization factor 2.0	\$/MMBtu	-1.3	-2.8

Constraints on African Ammonia Production

A5.20 Ammonia plants are complex and capital intensive, and require highly disciplined and competent operating and maintenance personnel. Direct application of ammonia for fertilizing purposes is hardly used in Africa, and commercialization will depend on the sale of the product on the world market or for local fertilizer production. In general, the plant should be located close to a port.

Possible Fertilizer Products

A5.21 Fertilizers contain different components necessary for crop production, which can be broadly classified as follows:

- Primary nutrients: nitrogen, phosphate, and potash (NPK), approximately 95 percent by weight.

- Secondary nutrients: calcium, magnesium, and sulfur, approximately 4 percent by weight.
- Micronutrients: boron, copper, iron, manganese, and molybdenum, approximately 1 percent by weight.

As crop yields are increased by more adequate fertilization with primary nutrients, the need for secondary and micronutrients becomes the limiting factor. By weight, nitrogen is the dominant component, constituting approximately 50 percent of all fertilizers produced.

A5.22 Fertilizers that may be produced based on nitrogen from ammonia are grouped as follows:

- Pure nitrogen fertilizers: urea, ammonium nitrate, calcium nitrate.
- Phosphoric acid-based ammonium phosphates (MAP, mono-ammonium phosphate, and DAP, di-ammonium phosphate).
- Mixed fertilizers based on phosphoric acid, ammonia, and solid urea (UAP, urea ammonium phosphate)
- Compound fertilizers (NPK).

This study focuses specifically on urea owing to its high nitrogen content and favorable production cost. CO_2 is a major by-product from ammonia production, and ammonia and CO_2 in turn are the main constituents in the urea production. One metric ton of ammonia produces 1.74 t of urea.

Market for Urea

A5.23 World production of urea is estimated to reach 40 million t in 1997. African production is estimated to be 2.6 million t in 1997. Urea is the most popular form of nitrogen fertilizer, due to its very high nitrogen content.

A5.24 Urea, the chemical formula of which is $CO(NH_2)_2$, has a nitrogen content of 46.6 percent, is generally preferred as a fertilizer for rice production, and constitutes the main nitrogen fertilizer used in Asia. Urea is also used as a cattle feed supplement where it may replace a part of the protein requirements and has numerous industrial uses as well. To satisfy the nutrient requirements for other crops, urea will have to be used in combinations with sources containing phosphorus and potassium. Because urea is produced from ammonia and CO_2, which is a by-product of ammonia production, all urea plants are located adjacent to or very near an ammonia plant.

A5.25 International trade is very important to the world's urea industry; 26 percent of total production is traded. Forty percent of African production is traded, and about 85 percent of this constitutes exports from Libya. Nigeria, Egypt, and South Africa are other exporters. Total African exports of urea in 1997 were estimated at 1.0 million t. The 1997 import estimate was 0.7 million t, with no one country dominating the imports.

A5.26 The price of urea has varied between $110 and $230 in the 1990s. Prices fluctuate with season and agricultural activity level. A typical intercontinental shipping charge for granulated urea would be $20–25/t. The rate varies with ship size, parcel size, and season.

Feedstock for Urea

A5.27 In ammonia-urea complexes, where all the ammonia is used to make urea, the amount of CO_2 derived from methane feedstock may not be quite sufficient for urea synthesis. Urea requires a CO_2-to-NH_3 ratio of 1-to-2, whereas the production of ammonia by reforming of pure methane produces a CO_2-to-NH_3 ratio of 7-to-16. It will therefore be advantageous to use gas that contains enough higher hydrocarbons to supply sufficient CO_2 for urea production. As an alternative, additional CO_2 can be obtained from stack gas from combustion of fuel in the reformer furnace, but this alternative is relatively expensive.

A5.28 Energy requirements for a 1,740 t/d ammonia-urea complex are as follows:

Ammonia, 1,000 t/d	33.0 GJ/t
Urea part	5.0 GJ/t
Total (33+5)/1.74	21.8 GJ/t

Urea Process

A5.29 Commercial production of urea is based on CO_2 and ammonia. The reaction proceeds in two steps: (1) formation of ammonium carbamate, and (2) dehydration of ammonium carbamate. These reactions may be expressed as follows:

(1) $2NH_3 + CO_2 \rightarrow NH_2CO_2NH_4$

(2) $NH_2CO_2NH_4 \rightarrow CO(NH_2)_2 + H_2O$

The first reaction is highly exothermic while the second is moderately endothermic. There are several process options, but most new plants use total effluent recycle by which all the unconverted ammonia and CO_2 are recycled back to the reactor to extinction. This process is preferred due to the simplicity of operation. The effluent from the urea reactor contains urea and water in addition to unconverted carbamate and residual ammonia. These components are separated to give a relatively pure urea solution. In order to separate carbamate, it has to be heated to decompose it to CO_2 and ammonia, which is the reverse of the first reaction step. The ammonia and CO_2 are removed from the solution as gases in addition to some water in vapor form. The urea produced has a purity of approximately 75 percent. The solution can be used directly to make mixed fertilizer solutions (UAP) or further concentrated by evaporation to a melt (98–99 percent purity) before prilling or granulation to pure urea.

Licensers for Urea

A5.30 Major licensers for the process include the following:

- Monsanto.
- Snamprogetti.
- Uhde.
- Stamicarbon.
- Mitsui Toatsu.

Typical Urea Plant Size

A5.31 Plant capacities vary between 500 t/d and 2,000 t/d. For a 1,000 t/d ammonia plant, the urea production capacity will be 1,740 t/d.

Investment Cost, Ammonia, and Urea

A5.32 For a selected plant capacity of 1,000 t/d ammonia plant and a downstream 1,740 t/d urea plant, the costs are as follows:

Ammonia 1,000 t/d, battery limits, U.S. Gulf Coast	$125 million
Urea 1,740 t/d battery limits, U.S. Gulf Coast	$100 million
Common offsites	$125 million
Total ammonia-urea plant	$350 million

Key Results for Ammonia-Urea Plants and Sensitivity Analysis

A5.33 The key results for ammonia and urea plants are shown in Table A5.2. The maintenance costs are high because of solids handling. At a localization factor of 1.3 or higher, a substantial reduction in capex or increase in product price would be required for this process to be commercially viable. At a localization factor of 1.3, a product price increase of 15 percent and 40 percent would be needed to bring the gas value up to $0.5/MMBtu for the larger and smaller plant sizes, respectively.

Table A5.2 Characteristics and Economic Analysis of Ammonia-Urea Plants

Data item	*Unit*	*Large*	*Medium*
Ammonia basis	t/d	1,800	1,000
Single unit urea capacity	t/d	3,130	1,740
Single unit annual capacity	t/y	1,065,000	592,000
Capex, including offsites	million $	510	350
Maintenance cost (5% of capex)	million $/y	26	18
Operating cost, excluding feed gas	million $/y	14	9.3
Feed gas consumption	billion scf/year	23	13
Construction period	years	3	3
Operating period	years	25	25
Sale price for urea	$/t	145	145
Gas consumption, 25-year lifetime	tcf	0.58	0.32
Gas Values			
Localization factor 1.0 (base case)	$/MMBtu	1.1	-0.3
Localization factor 1.3	$/MMBtu	-0.5	-2.3
Localization factor 1.5	$/MMBtu	-1.6	-3.6
Localization factor 1.75	$/MMBtu	-2.9	-5.2

Note: Gas use (methane), 22,000 scf/t urea. The operating cost is scaled up linearly from ammonia, since it is more costly in a urea plant with much solids handling. The cost of ammonia as a feedstock to the urea plant is not included, because the plant considered here is a combined ammonia-urea plant, where natural gas is the only feedstock and urea is the only product. There will normally be a small shortage of CO_2 for the urea plant, which has not been considered in the above calculations.

Annex 6. Synthetic Fuels

Sources: Exxon, Hindsford, Rentech, Sasol, Shell, Statoil, and Syntroleum.

Concept

A6.1 The objective is to convert natural gas to a synthetic liquid fuel in the form of a synthetic crude oil or a synthetic high-grade, clean-burning diesel. The process units use a modern version of the well-known Fischer-Tropsch (F-T) process, developed in Germany in the 1920s. This technology area, when using natural gas, is commonly referred to as gas-to-liquids (GTL).

Product Characteristics

A6.2 The synthetic hydrocarbons discussed in this section comprise a number of different products. They are primarily straight chain hydrocarbons of varying carbon number. Further processing can shorten the overall chain length by mild hydrocracking. As products ready for the market, they may be broadly grouped into two different categories:

- Synthetic crude oil or "syncrude," a product similar in properties to a fairly high grade crude oil, and may be mixed into crude and sold as such.
- Synthetic fuel or "synfuel," a product similar to a high-grade diesel fuel, with a high cetane number and high purity, and free of sulfur and other impurities. Synfuels may be sold as a diesel substitute, or as a diesel blending stock for upgrading low-quality diesel.

Market for Syncrudes and Synfuels

A6.3 In theory, the market for crude oil and diesel substitutes is practically unlimited. If the total world crude production is 60 million b/d, it would take well over 200 tcf of gas per year to produce the same quantity of crude from natural gas, or more than 5,000 tcf over a 25 year period. The latter corresponds to the current total world natural gas reserves. It may safely be concluded that even a massive, new synthetic crude or fuel industry based on natural gas would account for only a fraction of the total world crude market. In theory, there is a potential market for synthetic diesel anywhere in the world where diesel is imported. There are two principal constraints:

- There must be sufficient feed gas in the field, adjacent to which the GTL plant would be built.

- The economics must be improved in terms of cost in order to compete with world market crude or diesel.

A6.4 With respect to the first constraint, a very large GTL plant (50,000 b/d) would consume 4.25 tcf of gas over a 25-year lifetime. This reserve requirement alone excludes the majority of gas-producing fields in Sub-Saharan Africa, and the large-scale production of synfuels is therefore not viable for utilizing the gas from marginal fields with reserves of less than 2 tcf. In order to accommodate gas reserves less than 2 tcf, with the majority being less than 1 tcf, the GTL plant capacity would need to be much smaller than the large-scale plant. A plant capacity of 12,000 b/d corresponds to gas consumption over 25 years of 1 tcf. If the field in question is only 0.5 tcf, the corresponding plant capacity would be only 5,900 b/d. Consequently, for a GTL plant to be viable for gas fields of about 1 tcf, the plant must be able to produce synthetic fuels at competitive prices even for plant capacities as low as 5,000 b/d.

A6.5 As for the second constraint, it is currently estimated that these synthetic products will be competitive at a world crude price above $19–20/bbl. A number of companies are working actively to improve upon this target, and there is little doubt that competitiveness will be achieved within a few years. The price obtainable for syncrude would be that of the current crude market price, with a possible premium for superior quality. The price obtainable for synfuel to be used as diesel could be $6–7/bbl above the crude price. A crude price in the range $16–18/bbl would therefore correspond to a synfuel price of $22–25/bbl.

Plant Size

A6.6 Plant costs for synthetic fuel production are still very high, and commercial considerations are currently given to very large plants, on the order of 20,000–50,000 b/d, by some of the major developers of this technology, including Exxon and Sasol. Others, including BP, Hindsford, Rentech, and Syntroleum, claim to be close to the commercialization of small plants, down to as low as 2,500–5,000 b/d. Such plants would enable commercial development of gas reserves that are small, or remote and isolated. Making small GTL plants economic would represent a significant breakthrough in the area of synthetic fuel production.

Process

A6.7 There are two distinct reaction pathways for converting natural gas to liquid hydrocarbons. One, commercialized by Mobil in New Zealand in the 1980s, converts gas to methanol, and methanol to liquid hydrocarbons. The process is not considered economic at present. The alternative approach is to convert natural gas to syngas, and syngas to hydrocarbons via F-T synthesis. All the research and development efforts in GTL currently underway focus on the second approach. More specifically, natural gas is converted in three steps.

(1) Syngas generation, converting natural gas and steam into a 2-to-1 mixture of hydrogen (H_2) and carbon monoxide (CO), which are feedstocks for F-T synthesis. Depending on the required plant capacity, a number of syngas processes are available, including steam reforming, combined reforming, partial oxidation, autothermal reforming, and other proprietary processes. Small plants usually favor steam reforming while large plants favor autothermal reforming or proprietary processes, for example, Exxon's fluid bed syngas process. It should be noted that syngas production accounts for 50–60 percent of the total plant cost. It is thus in the syngas plant that the capital cost reductions should be achieved as much as possible.

(2) The F-T synthesis, converting the syngas into $-CH_2-$ units, which combine to form hydrocarbons of varying chain length (C_1-C_{100}). The chain length depends on the nature and selectivity of the catalyst and reaction conditions. The product is chiefly a mixture of straight chain hydrocarbons, which are further processed. The synthesis reaction is strongly exothermic, and hence an efficient cooling system linked to the reactor is needed to remove the heat of reaction. Each F-T licenser offering their process on the market has their own, proprietary catalyst system. The catalyst for GTL is based on iron (particularly those processes involving coal gasification) or cobalt (more active and selective than iron). There are three main types of F-T synthesis reactors, all of which have been used commercially by Sasol:

- Fluidized bed reactor (Synthol and Advanced Synthol).
- Tubular fixed bed reactor (Arge), in which the feed passes through parallel tubes in which the catalyst is packed.
- Slurry phase reactor, where the catalyst is suspended in a slurry consisting of liquid wax and catalyst particles. The gas bubbles rise through the slurry and are converted to more wax in the F-T reaction. The product wax is separated from the catalyst particles. The slurry reactor is now the reactor of choice. The chief advantages are its simple design and moderate cost, much larger single-train capacity, better heat transfer and temperature control, and the ability to change the catalyst while the reactor is in operation without the need for shutting down.

(3) Upgrading of the F-T products to the desired marketable product, typically through a combination of distillation, hydrogenation, and/or mild hydrocracking. Upgrading may be relatively simple, for producing light synthetic crude (typical API density of 52°) as a refinery feedstock, or it may be more elaborate, producing a high-grade, synthetic diesel fuel, free of sulfur and aromatics, to be used either directly or as a diesel-blending stock to be mixed with lower-grade, crude-derived diesel.

Feedstock

A6.8 It is generally agreed that it takes 10 GJ or 10,000 scf of natural gas to produce one barrel of syncrude or synfuel. Consequently, gas consumption over a 25-year lifetime would be as follows:

0.425 tcf for 5,000 b/d

0.85 tcf for 10,000 b/d

1.7 tcf for 20,000 b/d

4.25 tcf for 50,000 b/d

A6.9 From the point of view of the present study, which deals with gas reserves limited to 2.0 tcf, the upper limit of relevant synfuel plant capacities is about 23,500 b/d. For the majority of the fields considered in this report, however, the maximum plant capacity would be below 10,000 b/d. Currently, such small plants have not been demonstrated to be economic. This is further discussed below under investment costs.

Early Concepts for Synfuel or Syncrude

A6.10 The production of synfuel on a large scale was first developed in Germany by Fischer and Tropsch in 1923, based on syngas produced by coal gasification. The process was used successfully in Germany to secure the supply of fuel during World War II. Most synfuel processes even today are based on modifications of the original F-T process.

Mobil-New Zealand MTG: Methanol-to-Gasoline Process

A6.11 A large-scale plant was completed in New Zealand in the 1980s, including a conventional large natural gas to methanol plant, and a novel process called "methanol-to-gasoline" (MTG), based on a shape-selective zeolite catalyst (that is, not F-T). The zeolite process may be simplistically described as a way of "squeezing" water out of the methanol molecule, converting methanol to water and $(\text{-CH-})_n$. The MTG plant has since been discontinued for being uneconomic.

Shell, Malaysia, SMDS: Shell Middle Distillate Synthesis

A6.12 A 12,000 b/d plant was completed in Bintulu, Malaysia, in the early 1990s, using a fixed bed F-T process and a Shell proprietary catalyst system at a capital cost of $850 million. A 50,000 b/d GTL plant based on the SMDS technology would cost $1.5 billion to build, and would be equivalent to $30,000 per daily barrel capacity. The Bintulu plant is notable for its flexible product capability; the product distribution can shift between naphtha, gasoil/diesel, kerosene, solvents, detergent feedstocks, waxy raffinates, and waxes. The plant has been in operation since May 1993.

Sasol Synfuels International, Republic of South Africa

A6.13 Sasol in the 1950s began commercializing the F-T process, and developed a high-temperature F-T process based on syngas from coal gasification (the Synthol process). Sasol has operated this process from 1955 in Sasol One to produce a high-quality, high-cetane, sulfur-free synthetic diesel, suitable as a diesel blending stock for reducing the sulfur and aromatic content of conventional, crude-derived diesel. Sasol commissioned new, significantly larger plants (Sasol Two and Sasol Three) in the early 1980s, and is currently producing 150,000 b/d of synthetic fuel based on coal, making them the largest synfuel producer in the world. Sasol is now offering, on a license basis, a 20,000 b/d synfuel unit. Sasol has licensed their synfuel technology to Mossgas, producing synfuel from natural gas in their Mossel Bay plant on the southern coast of South Africa. More recently, Sasol signed a memorandum of understanding with Qatar General Petroleum Corporation and Phillips Petroleum Company to build a 20,000 b/d GTL plant at Ras Laffan, Qatar. The plant is based on Sasol's proprietary slurry-phase distillate process.

A6.14 Sasol has entered into an agreement with Statoil of Norway for joint development of Sasol synfuel plants supported on an FPSO. Sasol has also entered into an agreement with Haldor Topsøe of Denmark for joint development of syngas production plants for the F-T process.

Ongoing Development in Synfuel and Syncrude Technology

A6.15 A number of companies is engaged in considerable research and development efforts for producing hydrocarbons from natural gas. They include Exxon, Statoil, British Petroleum, Air Products, Syntroleum Corporation, Rentech Inc., and Hindsford Pty, in addition to Mobil, Shell, and Sasol mentioned in the above. The objectives of research and development are to reduce the syngas plant cost, improve catalyst selectivity-activity and reactor technology, and perhaps, above all, to reduce the overall plant cost below $20/bbl to be competitive with crude oil processing. While some players, such as Exxon and Sasol, concentrate on very large plants up to 50,000 b/d, others, including Syntroleum, Rentech, and Hindsford, have focused on much smaller plants, as low as 2,500 b/d.

Exxon

A6.16 Exxon recently announced the development of a new second generation process, Advanced Gas Conversion or AGC-21. The three stage process comprises the following:

- Proprietary fluid bed syngas generation.
- Slurry phase F-T synthesis, using a cobalt catalyst.
- Fixed bed product upgrading by mild hydrocracking.

The syngas is fed into a slurry bed F-T reactor loaded with a cobalt catalyst. The AGC-21 reactor produces high yields of high molecular weight paraffins with a high wax content. This material is upgraded by means of mild hydrocracking and hydroisomerization in a tubular, trickle bed reactor, producing a water-white product with a pour point below 2°C, which can be transported in pipelines and conventional tankers. This product is free of sulfur and aromatics, as well as other impurities usually found in natural crude products, making it a premium blending stock for a wide range of high-quality refinery products, such as diesel and jet fuel. Exxon operates a 200 b/d demonstration plant in Baton Rouge, Louisiana. Exxon has not published their cost estimates for these plants, but other sources indicate a potential cost of $20,000–24,000 per daily barrel capacity, and a production cost that currently competes with a crude price of $20/bbl. The latter is expected to come down toward $15–16/bbl.

Rentech Inc., Denver, Colorado

A6.17 This company has developed their own F-T catalyst to produce a premium grade diesel fuel in a slurry reactor, which is downstream of a steam-reforming syngas generation plant. Rentech is focusing on small plants in the range of 500–5,000 b/d. They estimate the capital cost of $20,000–30,000 per daily barrel capacity for a 5,000 b/d plant on a grassroots basis in an industrial country. The products of the Rentech process are reportedly a clean-burning, premium grade diesel fuel that is suitable for vehicle use without any engine modifications, and naphtha for further chemical processing. Rentech has recently announced a cooperation agreement with Texaco Group Inc. to accelerate the development and licensing of the process technology and to exploit the technology commercially on a worldwide basis.

Syntroleum Corporation, Tulsa, Oklahoma

A6.18 This company has proposed their own F-T process for converting natural gas to synthetic fuels. The process consists of two steps. First, natural gas is partially oxidized with air (rather than oxygen) to a nitrogen-diluted syngas consisting mainly of CO and hydrogen in a proprietary, air-blown, autothermal reformer. This involves the special feature that the syngas generation is not oxygen blown, as in the case of more conventional partial oxidation, combined reforming or autothermal processes, and no air separation plant is needed. In the second step of the process, the syngas is polymerized into hydrocarbon chains of various lengths. The nitrogen from air passes through both steps as an inert and is rejected to the atmosphere at the end of the process. Both steps are highly exothermic. The ability to use air rather than having to separate oxygen from nitrogen reduces the capital cost of the plant and is claimed to be one of the reasons their process need not be large scale to be cost-effective. A second special feature of the Syntroleum process is its once-through character, on account of their proprietary cobalt F-T catalyst. Consequently, no recycle system is needed, reducing the plant cost further. Syntroleum has expended great efforts to increase the selectivity of the catalyst toward shorter-chain hydrocarbons so as to eliminate wax problems, while at the same time minimizing the production of C_1 to C_4. The selectivity of the catalyst eliminates the need for hydrocracking which converts long-chain hydrocarbons to short-chain hydrocarbons. In addition, this catalyst is claimed to reduce the operating pressure of the process, and enable the use of a higher-capacity fluidized bed reactor than those used for other catalyst systems.

A6.19 So far, this process has been tested in a 2 b/d pilot plant only, and full scale-up remains to be demonstrated. Syntroleum is focusing particularly on making small plants, even as low as 2,500 b/day, economic. Syntroleum is en route to developing a barge-mounted synfuel plant with capacity up to 10,000 b/d. The size of a 2,500 b/d plant is reported to be 100 ft × 500 ft = 50,000 ft^2 or 5,500 m^2. A recent study of a "second generation" Syntroleum design of a 5,600 b/d GTL plant undertaken by Syntroleum claims that the capital cost of the plant, located on the U.S. Gulf Coast and equipped to produce diesel, kerosene, and naphtha, is $17,300 per daily barrel capacity.

A6.20 Syntroleum has cooperation agreements with Texaco, Arco, Marathon, Brown & Root, and Bateman Engineering. Texaco, Brown & Root, and Syntroleum recently announced an agreement to develop a 2,500 b/d GTL plant.

Hindsford Pty. Ltd., Victoria, Australia

A6.21 Hindsford Synfuels Limited of Australia has proposed a synfuel process for small plants in the range of 700–3,400 b/d. The process comprises a partial oxidation process for syngas production, and a fixed bed reactor for the F-T process. The plant consists of small modules. The capital cost is stated to be on the order of $15,000–18,000 per daily barrel capacity.

British Petroleum, United Kingdom

A6.22 BP has recently announced a new proprietary process for converting natural gas to syncrude or synfuels. The published data at this time are limited. It appears that the target plant capacity is in the range 10,000–20,000 b/d. The main innovative element in the BP-process is a novel, compact reformer for producing the required syngas. This makes the process potentially attractive for use on an FPSO.

Innovative Developments

A6.23 While Sasol has successfully adopted the old Fischer-Tropsch technology to produce liquid fuels from syngas made by coal gasification, and has also licensed a process based on natural gas, there is a great need and potential for innovation in improving catalyst systems, reactor technology, and syngas generation, as well as making small plants, possibly mounted on FPSOs, economic.

A6.24 If and when synfuel plants with capacities of 5,000 b/d or less are demonstrated to be commercially viable, then such a process could lead to the development of remote, small gas fields, and in addition open up opportunities for barge-mounted (FPSO-based) synfuel plants in offshore locations.

Investment Cost

A6.25 The investment cost of a synfuel unit is crucial in the economic evaluation of the technology. The published figures span a fairly wide range, from conservative estimates of established technology to more optimistic estimates of novel technology, for various plant sizes. It has not been possible within the scope of this study to evaluate rigorously cost estimates provided by various companies, but the published estimates may be summarized as follows.

A6.26 Sasol reports for a 10,000 b/d module a figure of $300 million or $30,000 per daily barrel capacity. Larger units would benefit from economies of scale. Using a scaling factor of 0.65 to account for size differences, a 20,000 b/d module would cost $470 million, or $23,500 per daily barrel capacity. As GTL technology is under active development, it is not unrealistic to expect that these figures would come down in the future as a result of further development.

A6.27 Other current estimates range from $15,000 to $30,000 per daily barrel capacity for capacities down to 1,000 b/d or lower. The lowest estimates currently published (but not fully verified) are $18,000–22,000 per daily barrel capacity for a 5,000 b/d plant, and $15,000–16,000 per daily barrel capacity for a 10,000 b/d plant.

A6.28 Again, without attempting to evaluate which estimate is the most realistic, it may be concluded that the expected capital cost for natural gas-based synfuel plants below 10,000 b/d ranges at present from $15,000 to $30,000 per daily barrel capacity. In the following evaluations, a conservative figure for the onshore 10,000 b/d plant of $300 million is used, since this figure has been demonstrated commercially. Using a 0.65 scaling factor, the 20,000 b/d plant would cost $470 million. As regards operating and maintenance costs, there is good agreement among the data published by different companies: $5.00–6.60 per barrel, excluding the cost of natural gas. In the following evaluations, we have used $5.00 for a 10,000 b/d plant and $4.00 for the 20,000 b/d plant.

Key Results for Synfuel and Syncrude Plants

A6.29 The key results for synfuel and syncrude plants are shown in Table A6.1 for onshore applications, and in Table A6.2 for offshore applications. The FPSO application assumes that the product is syncrude, a product that is mixed into natural crude produced on the same FPSO and sold as crude at crude prices. It will probably be more economic to produce synfuels onboard and sell at a premium diesel price. The plant will be somewhat more expensive in order to produce synfuels, but the economics would likely be improved.

Table A6.1 Characteristics and Economic Analysis of Onshore Synfuel plants

Data item	*Unit*	*Large*	*Medium*	*Small*
Single unit daily capacity	b/d	20,000	10,000	5,000
Single unit annual capacity	b/y	6,800,000	3,400,000	1,700,000
Capex, including offsites	million $	470	300	190
O&M, excluding feed gas	million $/y	27	17	12
Feed gas consumption	billion scf/year	68	34	17
Construction period	years	3	3	3
Operating period	years	25	25	25
Sale price	$/bbl	22	22	22
Gas consumption, 25-year lifetime	tcf	1.7	0.85	0.43
Gas Values				
Localization factor 1.0 (base case)	$/MMBtu	0.6	0.1	-0.6
Localization factor 1.0, 30% capex decrease	$/MMBtu	1.0	0.6	0.1
Localization factor 1.0, 50% capex decrease	$/MMBtu	1.2	1.0	0.5
Localization factor 1.3	$/MMBtu	0.2	-0.4	-1.2
Localization factor 1.5	$/MMBtu	-0.1	-0.7	-1.6

Note: Operating and maintenance (O&M) cost, excluding feed gas, is $5.00 per barrel (Sasol). For the 20,000 b/d plant, this cost is taken as $4.00 per barrel.

A6.30 The price at the production site of the finest paraffinic diesel available corresponds to about $25/bbl for a crude price of $18–20/bbl. Since it may not be possible to sell all the diesel produced at this elevated price, an intermediate price for high-quality diesel or diesel blend stock of $22/bbl is used in this study.

Sensitivity Analysis for Onshore Synfuel plants

A6.31 As Table A6.1 shows, a substantial reduction in capex would be required to make this process economic. Although localization factor variation is separated from capex reduction, any change in capex may be regarded as a result of either varying localization factor or change in capex at source, viz., the U.S. Gulf Coast. Because the future trend in GTL is expected to be in the direction of decreasing capex, a capex reduction of up to 50 percent is considered in the above table. For a more realistic localization factor of 1.3 or higher, a 50 percent reduction in capex relative to the base case would correspond to a U.S.

Gulf Coast capex reduction of 65 percent or higher. For the 10,000 b/d plant, the product price would have to increase by more than 15 percent to raise the gas value to $0.5/MMBtu at a localization factor of 1.0 and no change in capex. For the 5,000 b/d plant, the corresponding increase in product price required is 45 percent. A 50 percent reduction in capex corresponds to $12,000, $15,000, and $19,000 per daily barrel capacity for the 20,000 b/d, 10,000 b/d and 5,000 b/d plant sizes on a U.S. Gulf Coast basis. Even a 50 percent reduction in capex, however, is barely sufficient to make the 5,000 b/d plant economic. Including a localization factor of 1.3 or higher would make the process even more uneconomic. To raise the gas value of the 5,000 b/d plant above $0.5/MMBtu, the capex needs to fall to $19,000 per daily barrel capacity or lower, including the localization factor. At a localization factor of 1.3, the U.S. Gulf Coast capex would have to fall to less than $15,000 per daily barrel capacity.

Table A6.2 Characteristics and Economic Analysis of Syncrude Plants on an FPSO

Data item	*Unit*	*Medium*	*Small*
Syncrude daily production	b/d	10,000	5,000
Syncrude yearly production	b/y	3,400,000	1,700,000
Capex	million $	250	160
O&M cost	million $/y	20	14
Feed gas consumption	billion scf/year	34	17
Construction period	years	3	3
Operating period	years	25	25
Sale price	$/bbl	16	16
Gas consumption, 25-year lifetime	tcf	0.85	0.43
Gas Values			
Localization factor 1.0 (base case)	$/MMBtu	-0.3	-1.0
Localization factor 1.0, 30% capex decrease	$/MMBtu	0.1	-0.4
Localization factor 1.0, 30% capex decrease, 50% price increase	$/MMBtu	0.9	0.4
Localization factor 1.0, 50% capex decrease	$/MMBtu	0.4	-0.1
Localization factor 1.3	$/MMBtu	-0.7	-1.5

Note: O&M = operating and maintenance. This concept is for a syncrude plant of 10,000 b/d capacity, mounted on an FPSO which also contains the oil and gas production and separation plant. Fifty percent of the infrastructure is charged to the oil plant, and the cost estimate for the synfuel plant proper is thus reduced by one-sixth from the stand-alone plant cost estimate.

Sensitivity Analysis for FPSO

A6.32 As Table A6.2 indicates, even if the capex were halved, neither plant would be economic if the price of syncrude is \$16/bbl. If a 30 percent increase in capex is accompanied by a 50 percent increase in the price of crude (that is, \$24/bbl), then the 10,000 b/d would have a gas value of \$0.9/MMBtu at a localization factor of 1.0, but the 5,000 b/d plant would remain uneconomic. As before, a substantial reduction in capex is needed before this technology can be considered on a commercial basis.

Field Size Aspects

A6.33 According to one of the synfuel technology companies, some 3,500 gas fields in the world have gas reserves of less than 0.25 tcf. This means that if the synfuel technology can be made commercially viable in small plants of 2,500–5,000 b/d, requiring 0.2 to 0.4 tcf of natural gas over 25 years, small gas fields, thus far totally unprofitable, could then be commercially developed. These fields could be developed without damage to the environment, so that they could yield products that are also environmentally benign, such as a clean, sulfur-free diesel. Equally important, this would significantly increase the world's total recoverable petroleum reserves by converting unprofitable discoveries to profitable fields.

Locational Consideration

A6.34 Synfuel products from land based plants is diesel ready for immediate use, and may be sent directly for storage and local distribution, or to a nearby refinery as a diesel blending stock. No downstream facilities are needed. However, the cost estimates assume a greenfield location in an industrial country, and should perhaps be increased to reflect any remote, unindustrialized location. In principle, a land-based synfuel plant may be erected adjacent to any gas field, and the product shipped in normal tankers or even tank cars to the nearest consumption centers. For the offshore FPSO-mounted syncrude plant, the situation is slightly different. The product could be synthetic crude to be mixed with the natural crude produced from the same plant and sold as such at the current crude market price. In such cases the capital cost estimate for the FPSO above is possibly on the conservative side, as no correction is made for the simpler upgrading step. However, no data are available for this simple syncrude version. The alternative is to produce high-grade diesel. The disadvantage would be the need to have two sets of segregated storage tanks on the FPSO, as well as in the shuttle tanker taking the two products (crude and diesel) to the market. In any case, the FPSO must be located at the gas field and the cost of shuttling the product(s) to the market is included in the evaluation as part of the operating and maintenance cost used above.

Conclusion Regarding Synfuels

A6.35 The maximum capacity synfuel plant that can be accommodated within the maximum field size considered in this study is 23,500 b/d, consuming 2.0 tcf of gas over 25 years. This may possibly be economically feasible using current technology. However, only a very few fields in Sub-Saharan Africa are as large as 2 tcf, and the majority are considerably smaller than 1 tcf. Thus, from the point of view of gas supply, the minimum plant capacity should preferably be below 6,000 b/d, corresponding to 0.50 tcf on a lifetime basis. The calculations in this study indicate the maximum allowable capital cost of a 5,000 b/d plant to be $97 million or $19,400 per daily barrel capacity.

A6.36 Successful development of small gas fields for synfuel production may be only a question of time. With novel syngas processes, more selective catalyst systems, and more cost effectively engineered plants, there is good reason to expect the first 5,000 b/d synfuel plant to be contracted within the next few years.

A6.37 The concept of producing syncrude on an FPSO along with the production of stabilized (offshore) crude is not viable if the product cannot fetch a price higher than the current crude price. Even on an FPSO, the gas should be converted to synfuel, that is, high-grade diesel to be sold at a price reflecting its premium quality, even if this requires a somewhat higher plant capex. Data to estimate this cost differential are not available.

Annex 7. Dimethyl Ether

Source: Haldor Topsøe.

Concept

A7.1 The objective is to convert natural gas to dimethyl ether (DME) by a catalytic dehydration process to produce a gas that may be used as a clean-burning diesel substitute.

Product Characteristics

A7.2 At ambient pressure and temperature, DME is a gas. It is transported and stored under pressure as a liquid fuel similar to liquefied petroleum gas (LPG), viz., at 5 bar at ambient temperature.

State at room temperature and ambient pressure	Gas
Properties	Colorless, inflammable
Chemical structure	CH_3OCH_3
Molecular weight	46.1
Boiling point	-24.9°C
Vapor pressure at 20°	5.1 bar
Lower heating value	28,430 kJ/kg

Market

A7.3 The conventional use of DME is as an aerosol propellant. Current world DME production is 150,000 t/y. DME has been shown to be a clean and efficient substitute for diesel. The technology developers state that the potential market for DME is very large, but they do not specify its magnitude. It must be borne in mind that the use of DME as a vehicle fuel will require the development of a separate infrastructure for storage and distribution, as well as modification to the fuel injection system for all DME-fueled vehicles. If DME becomes accepted as a substitute for conventional diesel, demand for it will rise, and new production facilities will have to be developed. Haldor Topsøe's analyses show that the most economic route to DME is large stand-alone plants based on natural gas, for example, plants of 2,500–10,000 t/d methanol equivalent capacity. Depending on the gas cost, DME is estimated to be more expensive than conventional diesel fuel, but the advantages of DME are claimed to be very low tailpipe emissions, higher fuel efficiency, lower maintenance and overall better performance.

A7.4 From an environmental point of view, DME is an excellent fuel, meeting Californian ultra-low emission vehicle standards for medium duty vehicles and European standards for heavy duty trucks with regard to carbon monoxide (CO) and oxides of nitrogen (NO_X), and significantly better than conventional diesel fuel. DME, however, does not quite meet the U.S. standards for CO and NO_X for passenger cars.

Plant Size

A7.5 On account of high costs, viable plant sizes are very large, ranging from 1,800 t/d to 7,000 t/d of DME. The plant sizes evaluated here are 1,800 t/d and 4,300 t/d.

Process

A7.6 DME is currently produced in three steps: conversion of natural gas to syngas, conversion of syngas to methanol, and dehydration of methanol to DME. Topsøe's new DME process combines the latter two steps into one process where three reactions take place simultaneously in one reactor:

- Conversion of syngas to methanol.
- Conversion of CO and water to carbon dioxide (CO_2) and hydrogen.
- Dehydration of methanol to DME and water.

The net result is the conversion of syngas to DME. Methanol is an intermediate product, but is converted to DME in the same reactor and hence does not appear as a separate process stream.

A7.7 DME would be produced from syngas in large-scale, one-step plants, using a proprietary catalyst. The syngas required would be produced in a two-step combined reformer for capacities below 4,000 t/d methanol equivalent, and in an autothermal reformer for higher capacities. Both processes require oxygen and hence an air separation plant. One metric ton of methanol yields 0.72 t of DME. A large-scale plant will require a capital investment of about $360,000 per daily metric ton capacity.

Feedstock

A7.8 The feedstock is natural gas, requiring 44,400 scf/t of DME.

Licensers

A7.9 The DME process has been developed by Haldor Topsøe A/S in cooperation with Amoco Corporation, and is offered for licensing by these two companies.

Innovative Developments

A7.10 The innovation lies in promoting the use of DME as an alternative to automotive diesel, and developing large-scale plants for DME production, with the capacity of one plant being several times the total current world DME production of some 150,000 t/y.

Investment Cost

A7.11 Based on information supplied by Haldor Topsøe, the capital investments for large DME plants have been taken as $275 million for a 1,800 t/d plant ($153,000 per daily metric ton capacity), and $525 million for a 4,300 t/d plant ($122,000 per daily metric ton capacity).

Key Results for DME and Sensitivity Analysis

A7.12 The key results for DME are shown in Table A7.1. As seen from Table A7.1, the 4,300 t/d plant is commercially feasible in all cases, even at a localization factor of 2.0. At a localization factor of 1.3, the plant can sustain a fall in product price of 35 percent. At a localization factor of 1.5, the product price can fall by 25–30 percent, and the gas value still remains above $0.5/MMBtu. The 1,800 t/d plant is commercially viable for localization factors up to 1.75 at the specified product price. At a localization factor of 1.3, the gas value falls below $0.5/MMBtu if the product price falls by 25 percent. At a localization factor of 1.5, the gas price remains above $0.5/MMBtu after a 10 percent price reduction. If the localization factor is 1.75, no price reduction can be sustained. At 2.0, the product price would have to increase by 10 percent to bring the gas value up to $0.5/MMBtu.

Other Considerations

A7.13 While the advantage of the DME technology is the ability to produce a very high-quality diesel substitute from natural gas in a two-step catalytic process, the concept has several significant disadvantages from the point of view of utilization of marginal gas reserves in Africa for this purpose. For the process to be economic, large plants are required. The larger of the plants examined above, 4,300 t/d DME, will consume about 1.5 tcf of feed gas over an assumed life of 25 years, and the medium-size plant, 1,800 t/d DME, will consume nearly 0.6 tcf during the life of the plant. Only very few of the fields under consideration can sustain the necessary feed gas rate for adequate duration. Furthermore, the use of DME as a large-scale substitute fuel for trucks and other diesel engine vehicles requires a completely new infrastructure for storage, transportation and distribution. Finally, the use of DME will also require a new fuel injection system in all vehicles using it.

Table A7.1 Characteristics and Economic Analysis of DME

Data item	*Units*	*Large*	*Medium*
Methanol basis	t/d	6,000	2,500
Single-unit daily capacity	t/d	4,300	1,800
Single-unit annual capacity	t/y	1,462,000	612,000
Capex, including offsites	million $	525	275
Maintenance cost (2% of capex)	million $/y	11	5.5
Operating cost, excluding feed gas	million $/y	8.8	5.0
Feed gas consumption	bcf	65	27
Construction period	years	3	3
Operating period	years	25	25
Sale price	$/t	190	190
Gas consumption, 25-year lifetime	tcf	1.6	0.68
Gas Value			
Localization factor 1.0 (base case)	$/MMBtu	2.7	2.2
Localization factor 1.3	$/MMBtu	2.2	1.6
Localization factor 1.5	$/MMBtu	1.8	1.1
Localization factor 1.75	$/MMBtu	1.4	0.6
Localization factor 2.0	$/MMBtu	1.0	0.1

Note: The price of DME is taken as that of high-grade diesel, about $25/bbl or $190/t.

Conclusion

A7.14 In summary, within the boundaries of the present study, the DME concept presented here does not appear to offer a viable solution to the problem of utilizing marginal gas reserves in Africa. On an individual field basis, DME might be viable for larger gas reserves if the gas is piped to a large-scale industrial infrastructure such as the Kudu field in Namibia or the Pande field in Mozambique with pipelines to South Africa. The viability, however, needs to be examined in a separate feasibility study.

Annex 8. Gas-to-Olefins and Methanol-to-Olefins

Source: Norsk Hydro.

Concept

A8.1 The objective of gas-to-olefins (GTO) and methanol-to-olefins (MTO) is to convert natural gas to light olefins, more specifically ethylene, propylene, butenes, and some heavier hydrocarbons. The products of choice are ethylene and propylene. In GTO, gas is converted to methanol and methanol to olefins at one site. Alternatively one may choose to convert natural gas only to methanol at the gas field, and transport the methanol to another site for the MTO process. The latter option may be selected if there is a large polyolefin plant far from the gas field, as light olefins, being gaseous, are more costly to transport than methanol, which is a liquid at ambient temperature and pressure.

Product Characteristics

Ethylene

State at room temperature and ambient pressure	Gas
Properties	Colorless, inflammable
Chemical structure	$CH_2=CH_2$
Molecular weight	28.05
Melting point	-169 °C
Boiling point	-104°C

Propylene

State at room temperature and ambient pressure	Gas
Properties	Colorless, inflammable
Chemical structure	$CH_2=CH-CH_3$
Molecular weight	42.08
Melting point	-185°C
Boiling point	-47°C

Market for Olefins

A8.2 World production of ethylene and propylene was 52.3 and 27.7 million t, respectively, in 1994. The only African manufacturer of olefins is Algeria, which in 1994 produced 79,000 t of ethylene. Ethylene and propylene are petrochemical feedstocks. They are coproducts and in certain processes, substitutes. Ethylene is the largest-volume petrochemical produced worldwide.

A8.3 The world ethylene price level is about \$500/t. Propylene prices are about \$300/t. Prices for the two products normally fluctuate together, but imbalances may occur. In early 1995 propylene sold for \$800/t versus \$600 for ethylene. The present study assumes \$440 and \$360/t for ethylene and propylene prices, respectively.

A8.4 In the SADC Gas Utilization Study, olefin production from gas was investigated only for South Africa. Annual South African consumption of ethylene is 265,000 t and this quantity does not justify the construction of a separate South African production unit. Exports to world markets would be a prerequisite for profitable operations. A prefeasibility study undertaken in 1993 concluded, however, that there were insufficient gas resources available at the intended site to support a world-scale plant, requiring importation of LPG as an additional feedstock. For this reason, the ethylene option for South Africa was not investigated further.

Plant Size

A8.5 Norsk Hydro and UOP have concluded that economy of scale calls for considerable plant sizes. Three plant sizes are considered in the calculations of the gas value:

- 800,000 t/y C_2, 572,000 t/y C_3 and 172,000 t/y C_{4+}
  10,400 t per calendar day (t/cd) methanol equivalent
- 525,000 t/y C_2, 375,000 t/y C_3 and 113,000 t/y C_{4+}
  6,800 t/cd methanol equivalent
- 400,000 t/y C_2, 286,000 t/y C_3 and 86 000 t/y C_{4+}
  5,200 t/cd methanol equivalent

Process

A8.6 The methanol in the GTO route is produced inside the plant and feeds directly into the MTO process. In the MTO route, methanol is produced at one location and transported to another site for conversion to light olefins. The methanol, in both cases, is evaporated and fed into a fluidized bed reactor where the conversion to olefins takes place. The heat of reaction (the reaction is exothermic) is controlled by steam rising, and the reactor effluent is cooled by heat recovery or cooling water. The cooled olefin-rich gas is compressed, passed through a caustic scrubber to remove CO_2, and finally dried before it enters the product separation section where the effluent mixture is split into ethylene, propylene, and a C_{4+} mixture.

A8.7 At the heart of the MTO process is the catalyst. This specially developed shape-selective catalyst (SAPO-34) is based on a molecular sieve with a 4 Ångstrøm pore diameter. Within these pores, the methanol is dehydrated and combined to form olefins with high selectivity to ethylene and propylene:

$$2CH_3OH \rightarrow CH_2{=}CH_2 \text{ (ethylene)} + 2H_2O$$

$$3CH_3OH \rightarrow CH_2{=}CH\text{-}CH_3 \text{ (propylene)} + 3H_2O$$

$$4CH_3OH \rightarrow CH_3\text{-}CH{=}CH\text{-}CH_3 \text{ (butene)} + 4H_2O$$

The product distribution assumed in this report is 52 (carbon mole) percent ethylene, 37 percent propylene and 11 percent C_{4+}, but ethylene selectivity may vary between about 50 percent and 65 percent, depending on reaction conditions and catalyst formulation.

A8.8 The MTO process is of interest only when the low-cost gas source is far from the olefin user. The feedstock for the MTO process is (low-cost) methanol, not gas. MTO is therefore excluded from economic calculations in this study.

Feedstock for GTO

A8.9 The feedstock is natural gas. All feedstock consumption here is based on the production of ethylene, which in this case is 52 carbon mole percent of the total product. 4.75 t of methanol is assumed to be required per metric ton ethylene produced. The feedstock consumption for methanol is 32,000 scf of natural gas per metric ton of methanol. The feedstock consumption for GTO is thus about 152,000 scf/t ethylene. The gas consumption for the very large plant (800,000 t/y ethylene over 25 years), is 3.04 tcf, and for the 400,000 t/y plant it is 1.52 tcf. For lifetime consumption of about 0.5 tcf, the plant would have to be considerably smaller. For example, a 140,000 t/y ethylene plant consumes 0.57 tcf over 25 years. The plant sizes under consideration (selected on the basis of economics) consume more natural gas than the large majority of the field sizes considered in this study.

Licenser

A8.10 The process described here has been developed jointly, and is offered for licensing, by Norsk Hydro and UOP.

Innovation

A8.11 The chief innovation in this technology is the catalytic dehydration of methanol, with the potential advantage that the methanol may be produced at the gas source in very large plants, stored and transported to the MTO plant. Alternatively the olefins may be produced directly in a single plant (GTO). The reaction pathways are the same in MTO and GTO, but in GTO methanol goes directly to the methanol conversion reactor.

Investment Costs

A8.12 Based on information provided by Norsk Hydro, the capital expenditures for various plant sizes discussed here are as follows.

MTO, not including the methanol plant, based on methanol feedstock:

800,000 t/y ethylene: $370 million

400,000 t/y ethylene: $236 million

150,000 t/y ethylene: $125 million

GTO, including methanol as an intermediate product, based on gas as the feedstock:

800,000 t/y ethylene: $1,500 million 10,000 t/d methanol equivalent

525,000 t/y ethylene: $1,150 million 6,600 t/d methanol equivalent

Operating and Maintenance Costs

A8.13 Based on Norsk Hydro's data, this cost is $100/t for a plant that produces 150,000 t ethylene per year. The figure is scaled up for larger capacities, using the 0.65 scaling factor.

Sales Revenue

A8.14 Assumed free-on-board (FOB) product prices for remote sites are as follows:

Ethylene:	$440/t
Propylene:	$360/y
C_{4+}:	$130/y

The total revenues, based on the above figures, are

800,000 t/y ethylene, with propylene and C_{4+}: $580 million/y

525,000 t/y ethylene, with propylene and C_{4+}: $380 million/y

400,000 t/y ethylene, with propylene and C_{4+}: $290 million/y

150,000 t/y ethylene, with propylene and C_{4+}: $110 million/y.

Key Results for Onshore GTO

A8.15 GTO plants with ethylene capacities of 800,000, 525,000, and 400,000 t/y have been considered. The capacities for the different cases have been selected on the basis of the case published by Norsk Hydro, and scaled up or down, as needed, with a 0.65 scaling factor.

Table A8.1 Characteristics and Economic Analysis of Onshore GTO

Data item	*Units*	*Large*	*Medium*	*Small*
Single unit annual ethylene capacity	t/y	800,000	525,000	400,000
Capex, including offsites	million $	1,500	1,100	940
O&M cost, excluding feed gas	million $/y	130	110	82
Feed gas consumption	billion scf/year	120	80	61
Construction period	years	3	3	3
Operating period	years	25	25	25
Revenue from sales of olefins	million $/year	580	380	290
Gas consumption, 25-year lifetime	tcf	3.0	2.0	1.5
Gas Values				
Localization factor 1.0 (base case)	$/MMBtu	1.6	0.9	0.7
Localization factor 1.3	$/MMBtu	0.9	0.1	-0.2
Localization factor 1.5	$/MMBtu	0.5	-0.4	-0.8
Localization factor 1.75	$/MMBtu	-0.1	-1.1	-1.5
Localization factor 2.0	$/MMBtu	-0.7	-1.7	-2.3

Note: O&M = operating and maintenance. The capex, given by Norsk Hydro for the 525,000 t/y plant is $1,125 million. Selectivity to ethylene is assumed to be 52 carbon mole percent.

Sensitivity Analysis

A8.16 All the plants are commercially viable in the base case. At a localization factor of 1.3, only the largest plant has a gas value above $0.5/MMBtu. All other cases considered are not commercially viable at the specified product revenues. Sale revenues from GTO may vary either as a result of changes in olefin prices, or changes in product yield and product distribution (viz., ethylene selectivity being different from 52 carbon mole percent). At a localization factor of 1.3, an increase in sale revenue of 10 percent and 15 percent raises the gas value above $0.5/MMBtu for the 525,000 and 400,000 t/y plants, respectively.

Location

A8.17 As the light olefins produced by GTO are gaseous and expensive to store and transport, the GTO plant should be located adjacent to an olefin user, such as a polyethylene or polypropylene plant. These are very large and expensive plants. No such plant exists or is planned in Africa.

Annex 9. Iron Ore Reduction

Sources:

Private communication Dr. Leiv Kolbeinsen, SINTEF, Trondheim, Norway, Visiting Scientist at Carnegie Mellon University, Pittsburgh, United States.

Gas Research Institute, Chicago, United States.

VAI Voest Alpine Industrieanlagebau, Linz, Austria.

Lurgi Metallurgie GmbH, Frankfurt, Germany.

V. Bobrov (U.N. Economic Commission for Africa), "The African Iron and Steel Industry," Ironmaking and Steelmaking, 1993, Vol. 20, No. 5, p. 315.

Rolf Steffen and Hans Bodo Lungen, "Stand der Direktreduction," *Stahl und Eisen*, 1994, Vol. 114, No. 6, p. 85.

Daniel Johnston, "West Africa's Risks and Rewards," paper presented at Offshore West Africa '96 Conference, Libreville, Gabon, 5–7 November 1996.

Concept

A9.1 Direct reduction technology is a process for converting iron oxides to metallic iron by using natural gas as a primary energy agent. The method is referred to generally as DR, while the product of DR is referred to as DRI (direct reduced iron). DR is a potentially profitable way of utilizing marginal natural gas reserves in Africa if the gas source is not too far away from the iron ore source.

Product Characteristics

A9.2 The products of reducing iron ore with natural gas, DRI typically in the form of hot briquetted iron (HBI) or iron carbide, are the main feedstocks for steel production.

Market for DRI

A9.3 Total world production of steel in 1995 was about 750 million t, comprising 510 million t (68 percent) produced by the traditional blast furnace method, 210 million t (28 percent) made from scrap by the electric arc furnace method (EAF), and 30 million t (4 percent) by direct reduction of iron ore with natural gas (DRI). Total world production of steel via the blast furnace route has been nearly constant for the last five years, while the production from scrap substitutes, such as DRI, HBI, and iron carbide, increased steeply from 15 to 30 million t from 1988 to 1995. The main reason is that EAF-based steel is cheaper than traditional blast furnace-based production, not to mention the increasing concerns over the pollution caused by the blast furnace and coke oven technology. Prognoses within the steel making profession indicates continued steep growth in EAF steel, to 70 million t in year 2000 and as much as 300 million t in 2010.

A9.4 The need for high scrap quality to manufacture high-quality steel has driven the scrap prices up, and scrap substitutes such as DRI/HBI and pig iron will be of importance for quality conscious and viable steel production via the steadily increasing EAF steel-making route.

A9.5 DRI, input material for steel production, is a semifinished product whose market is steel plants. Eighty percent of world production is consumed in steel mills adjacent to the DR plant (captive production), while 20 percent is marketed, mostly in the form of HBI. The novel steel production minimills, such as those adopted by the U.S. company Nucor, are highly efficient, self contained "market mills," taking the EAF iron to their own steel mills, and producing steel of different quality.

A9.6 DRI is a substitute for scrap in the steel making process. Whenever a scrap shortage looms, electric furnace producers look for scrap substitutes, encouraging the construction of DR plants. When scrap prices rise above $130/t, additional DR facilities are activated in the U.S. market. DRI prices historically have been tied to scrap prices. In industrial countries DRI prices are comparable to the price of prime scrap and comparable to imported shredded scrap for developing countries. During the 1990s DRI prices have varied between $90 and $170/t.

A9.7 Developing countries have limited scrap resources. Close to 90 percent of world DRI production is therefore in developing countries. The SADC Gas Utilization Study assessed options for DRI production in Mozambique, Namibia and South Africa. Mozambique has significant magnetite resources in the Tete region, which could prove economic to beneficiate into DRI. Electric power from Cahora Bassa and gas from Pande could supply all energy and reduction requirements. However, the cost of setting up the infrastructure required may prevent the project from being competitive at present world market prices.

A9.8 Iron and steel manufacturing was considered in the assessment of possible gas utilization options for the Kudu field in the above study. It was concluded that iron making in Namibia had no regional advantage compared to a plant in South Africa, as all the raw material (iron ore) would have to be imported into Namibia.

A9.9 Besides increasing the use of DRI in the steel-making process at the Saldanha Bay plant in South Africa, the option for South Africa to export DRI to steel manufacturers in Asia was also studied. Asia imports scrap from Europe (2.8 million t for India, 1.6 million t for the Republic of Korea in 1994). Consideration was given to establishing a DR-type process, fed by gas from the Pande field in Mozambique, at three locations: Richards Bay, Maputo, and Phalarborwa. These options were considered economically attractive.

Plant Size

A9.10 The recommended plant sizes of new DR plants are about 1–2 million t/y.

Processes

A9.11 Traditionally hot metal (liquid iron with about 4 percent carbon content) was nearly exclusively produced by blast furnace using coke as the source of energy and as the reducing agent. Coke is produced in the coking plant from relatively scarce and expensive high grade metallurgical coal. The iron carriers are charged to the blast furnace as sinter or pellets, or as lump ore, or a mixture thereof. Due to the high cost of the coking coal and the unfavorable environmental effects of the blast furnace method, it became desirable to develop alternative methods of making steel. The hot metal is further processed with oxygen to steel in a converter. Hot metal production amounts to approximately 70 percent by weight of total steel production.

Blast Furnace Method

A9.12 The classical method for steel production is reduction of sintered or pelletized iron ore (iron oxides) in a blast furnace, together with coke made from coal in a coke oven, to produce hot metal (pig iron). This is converted to steel in an oxygen blown converter.

Electric Arc Furnaces Based on Scrap Metal

A9.13 An important development is based on the increasing use of scrap metal, which is melted for reuse in an electric arc furnace (EAF). This is more cost-effective than the coke oven–based blast furnace method, provided sufficient scrap iron of acceptable quality is available, along with electric power. EAF is much less harmful to the environment than the coke oven–based blast furnace method. The electric power consumption is about 410 kWh/t. The product from the EAF is crude steel. This method has given rise to a large number of scrap-based "minimills." In 1994 about 30 percent of all liquid steel was produced via the EAF route, and this percentage is expected to increase further in the future. In the past, the EAF route was utilized to produce "simple steel grades" with low steel purity requirements, due to the undesirable scrap impurities, such as copper, zinc, tin, and chromium. However, recent advances have made this technology competitive even in the high-quality steel market. The capex for a 300,000 t/y plant is about $60 million or $200 per yearly metric ton capacity.

Minimills and Low Capacity Utilization

A9.14 While there are steel plants of one type or another in many African countries, the rate of capacity utilization is low, with the 1993 average reported as being approximately 50 percent. The problem with low utilization is particularly severe with respect to ministeel plants based on imported feed material. The main reasons are as follows:

- Lack of imported material inputs such as scrap, sponge iron, pellets, and fuel.
- Insufficient power supply.
- Need for plant rehabilitation.
- Lack of professional management.
- Inadequate financing.
- Inadequate infrastructure.

Corex

A9.15 Corex is a smelting reduction process in which noncoking coal is used directly in a smelter gasifier as an energy carrier and reducing agent, eliminating the need for a blast furnace, sinter plant, and coke oven. Corex process is fed by lumpy ore or pellets or a mixture thereof, and coal, and produces a rich offgas which can be used in lieu of syngas in, for example, the Midrex process. The product of the Corex process is liquid hot metal similar to the product of the conventional blast furnace. Corex plants are in operation at Iscor's steelworks in Pretoria, South Africa. In the Republic of Korea, further Corex plants are under construction at Hanbo Steel, and a plant is under construction in Jindal in India. The Corex process is not relevant to the present study, except for the combined Corex and Midrex described below.

Direct Injection of Natural Gas into Blast Furnaces

A9.16 The Gas Research Institute (GRI) in Chicago has developed a method for direct injection of natural gas into blast furnaces, thereby replacing up to 50 percent of the traditional coke feed. This reduces the environmental burden, and reportedly may increase productivity by 25–30 percent compared to conventional blast furnace processes, and give savings in production cost of some \$4–5/t. Total U.S. gas use for blast furnace injection was 100 billion m^3. Natural gas may replace 1.1–1.2 times its own weight of coke. Blast furnaces use about 1,000 pounds of coke per ton of metal. This may be reduced to 660 or even 500 pounds by injecting natural gas. Natural gas used for this purpose was 35 bcf in 1986 and increased to 105 bcf in 1996. According to GRI, an all gas blast furnace with prereduction and fluidized melting could be developed in three to five years if funding for research and development were available. The process also allows lower temperature, down to 1,650°C, and has significant environmental benefits. The capex data required for an evaluation of this technology are not available, but the GRI technology might be found to be viable for use in existing blast furnace plants in Africa, such as those in Algeria, Egypt, Tunisia, Nigeria, Zimbabwe, and South Africa. This process is not included in the report's recommendations, but might be a subject of a separate feasibility study.

Direct Reduction

A9.17 A number of processes for DRI using natural gas have been developed, including Midrex, HyL III, Fior/Finmet, DRC, iron carbide, Arex, and Circored, of which Midrex is the most commonly used. As this study does not aim to provide a comprehensive overview of all DR methods, only some examples are discussed.

Midrex

A9.18 Provided by the Midrex Direct Reduction Corporation, this process is the most commonly used DR method, not using coal or coke at all. Natural gas is the only energy carrier and reducing medium. It is combined and mixed with two-thirds of the gas recycled back from the reduction shaft, and converted to reducing agents (H_2 and CO) in a reformer; the remaining one-third of the gas leaving the reduction shaft is used as a fuel for the reformer. The reduction gas is fed to the reduction shaft together with iron ore. The product is DRI or HBI. One disadvantage is that the iron ore feed must be lumpy or pelletized and thus costly, and the process cannot use the fines which is the form in which most iron ore is available. Nearly 50 Midrex modules are in operation or under construction worldwide.

HyL III

A9.19 This process, developed by HyL in Mexico, is similar to Midrex in many ways, also using natural gas and requiring lumpy or pelletized iron ore.

Combined Corex-Midrex

A9.20 As stated above in the section on the Corex process, an energy-rich tail gas is produced in the Corex plant. It can be used for a variety of metallurgical, chemical, and power generation processes. Of relevance here is the use of the Corex tail gas as a reducing agent for a DR shaft, in lieu of natural gas. The tail gas has to be treated to remove most of the oxidants, primarily CO_2, before its use in the Midrex process. Such a plant is under construction at Saldanha Steel mill in RSA, and at Hanbo Steel in the Republic of Korea.

Finmet

A9.21 This is a novel process developed by Voest-Alpine Industrieanlagebau, and Fior de Venezuela, and is a further development of the Fior process. It represents an improvement compared to the well-proven Midrex process in that the lower-cost and more abundant iron ore fines may be used directly in the redactors, thus eliminating the additional cost of buying lumpy ore or of pelletizing. The process uses fluidized bed technology. The product is HBI.

A9.22 The first commercial plant for 2 million t/y is under construction at Port Hedland, Australia. A further 2 million t/y plant for Orinoco iron in Venezuela has been contracted recently.

Circored

A9.23 Circored is also a novel process, developed by Lurgi Metallurgie GmbH. The process represents an improvement, similar to the Finmet process described above in that the lower-cost and more abundant iron ore fines may be used directly in the reduction reactor, thus eliminating the additional cost of buying lump ore or of pelletizing the fines.

A9.24 The technology uses a two-stage circulating fluidized bed and fluidized bubble bed reactor configuration instead of a shaft. The main product is HBI or DRI. A Circored plant with a capacity of 1 or 2 million t/y can be built in a single unit.

Technical Data

A9.25 Based on the data supplied by the two competing suppliers, VAI and Lurgi, technical data for the two novel DR processes, Finmet and Circored, are provided below.

Standard plant capacity	1 million t/y
Capex	\$220–250 million, including offsites
Areal requirements	30,000–40,000 m^2 for the total plant
Ore consumption	1.45–1.55 t fine iron ore per metric ton of final product (HBI)
Energy consumption per metric ton	11–12 GJ of natural gas and 150 kWh electric power.

The new DR-processes are now also available in units of 2 million t/y.

Feedstock

A9.26 The feedstocks for the DR processes are natural gas, about 12 GJ/t DRI and iron ore of various qualities, mainly "lumpy" or "fine ore." In addition, 100–150 kWh of electric power per metric ton of DRI is needed. The word "fine" in "fine ore" does not refer to superior quality, but to the small particle size compared to that of lumpy ore. Fine ore is more abundant and less costly. In traditional DR processes it had to be pelletized in order to make it usable in DRI-processes.

A9.27 The quality of the ore varies strongly from one deposit to another. The desired ore qualities are a high iron content, a minimal concentration of residuals, such as copper, nickel, and cobalt, which have a detrimental impact on the physical properties of the resulting steel, and a low content of gangue (minerals such as silica, magnesia, alumina, and titania), which can be removed during steel-making, although its removal increases the costs of steel-making (both capital and operating) as well as operational complexities. It is beyond the scope of this study to include the impact of iron ore quality in the economic calculations. For the sake of simplicity, only two qualities are considered here: the lumpy ore and the fine ore.

A9.28 As a cost component, natural gas represents approximately 30 percent of total unit production cost for DRI, and ultimately 12 percent of total unit production cost for slab steel. Therefore, a constant supply of high-quality, low-sulfur gas is critical.

A9.29 While the Midrex process requires the less abundant and more costly lumpy ore, the novel Fior/Finmet and Circored processes can utilize the more abundant fine ore. The difference in cost between these two major forms may be taken as about $20/t of iron feed mix. No further consideration on ore quality variations is included in the present study, although taking into account such differences would be essential in the final economics of a given project.

Licensers

A9.30 There are many licensers for the various iron reduction processes. Those considered in the present report are as follows:

- Lurgi Metallurgie GmbH.
- Voest Alpine Industrieanlagebau GmbH.
- HyL.
- Gas Research Institute.

Innovative Development

A9.31 The principal focus has been to develop processes that can use fine ore as a direct feedstock without having to pelletize. Other considerations are to improve efficiency, reduce cost, and reduce effluents to the environment, as well as to focus on iron carbide as an alternative to HBI.

Staffing Requirement

A9.32 The staffing requirement depends significantly on the plant location. For a 1 million t/y plant in a fairly remote location, about 0.5 staff-hours/t yearly capacity, corresponding to about 250 persons on the payroll, would be required. In a European DR plant, the staffing required could be 30–40 percent lower.

Key Results for Iron Ore Reduction

A9.33 The key results for iron ore reduction processes using lumpy iron ore and iron ore fines shown in Table A9.1. Localization factors are varied between 1.0 and 2.0.

Table A9.1 Characteristics and Economic Analysis of Iron Ore Reduction

Data item	*Units*	*Midrex*	*"New DR"*
Single unit annual capacity	t/y	1,000,000	1,000,000
Capex, including offsites	million $	225	230
Iron ore feed	million $/y	54	34
Maintenance cost (3.5% of capex)	million $/y	8.0	8.2
Other operating cost, excluding feed gas	million $/y	15	18
Feed gas consumption	billion scf/year	11	12
Construction period	years	3	3
Operating period	years	25	25
Sale revenue	million $/y	150	150
Gas consumption, 25-year lifetime	tcf	0.26	0.30
Gas Values			
Localization factor 1.0 (base case)	$/MMBtu	3.3	4.2
Localization factor 1.3	$/MMBtu	1.9	2.9
Localization factor 1.5	$/MMBtu	0.9	2.0
Localization factor 1.75	$/MMBtu	-0.3	0.9
Localization factor 2.0	$/MMBtu	-1.5	-0.2

Note: The "New DR" process data are based on data from two competing technology suppliers, Voest Alpine and Lurgi.

Sensitivity Analysis

A9.34 A 1 million t/y Midrex plant has a gas value of $3.3/MBtu in the base case. The value falls to $1.8 and $0.3 if the product price is reduced by 10 and 20 percent, respectively. At a localization factor of 1.3, a fall in product price of 10 percent lowers the gas value to $0.3/MMBtu. At a localization factors of 1.5 the process cannot sustain even a 5 percent decrease in product price. The product price would need to increase by 10 and 15 percent, respectively, for localization factors of 1.75 and 2.0 to increase the gas value above $0.5/MMBtu. A 1 million t/y "New DR" plant has a gas value of $4.2/MMBtu in the base case. The process is commercially viable at a localization factor of up to 1.75. In the base case the gas value is lowered to $0.9/MMBtu if the product price decreases by 25 percent. At a localization factor of 1.3, the process can sustain a decrease in product price of 15 percent, but if the product price decreases by 20 percent the gas value falls to $0.3/MMBtu. At localization factors of 1.75 or higher, the process cannot sustain a price fall. Even at a localization factor of 2.0, however, a 10 percent increase in product price raises the gas value to $1.2/MMBtu.

Location of DR Plants

A9.35 It must be emphasized that there are field specific, logistical factors that must be considered in evaluating the profitability of a new DR plant in Africa (and indeed anywhere else). Ideally, with respect to selecting the best site for a new DR plant, iron ore, gas reserves, an existing steel plant or minimill, and an export harbor should all be at the same location. Such a situation, however, never occurs. Thus one is obliged to transport either the gas or the iron ore, or both, to the existing or planned DR site. It would not be desirable to transport DRI (if DRI is the product) any appreciable distance because of the tendency of DRI to oxidize. Therefore, the distance from the DRI plant to the end-user, which is either the EAF plant or a minimill, becomes critical and should be minimized. HBI, on the other hand, can be easily transported. DRI can be carburized with gas treatment on the surface, to provide greater stability. More important, an alternative product from the DRI process is iron carbide, which is stable during storage and transport, and may be transported to a more distant DRI user. The transport cost must of course be considered.

A9.36 An extensive logistical analysis would be required to take into consideration local conditions and distances, to compare various scenarios, and to evaluate the profitability of the best option. Since the present study does not include specific field evaluations, no such logistical analysis is provided. Such an analysis may completely change the results of the more simplified evaluations included, where the main elements are the plant size, capex, operational expenses, ore cost, and product price.

A9.37 Other elements in the fairly complex logistical evaluation may include the following:

- Whether there is production from ore reserves, or if a costly mining venture is required to produce the ore.
- The actual distance and terrain between ore, gas, and potential site.
- Existing railways, pipelines, ore slurry lines, or the cost of building anew.
- Distance from potential site to the DRI buyer.
- Distance from EAF plant to the export harbor, if any.
- Transport cost in unit/kilometer for gas, ore, and DRI product.
- The existence or absence of an industrial infrastructure, trained personnel resources, well-tested managerial systems, and traditions.

A9.38 Clearly, the optimal site selection of a new DRI plant is completely project specific, and must be subject to a rigorous logistical evaluation. While it is not the objective of the present study to evaluate specific DRI-sites, a few indications of the possible localization of future DRI plants are given in the next section.

Metals Other than Iron-Alloying Metals

A9.39 According to Bobrov, Africa is well endowed with several important alloying metals, such as manganese, chromium, cobalt, and nickel, of which unquantified and undeveloped deposits are known to exist in more than 25 countries in the region. Africa contains 78 percent of the world's known reserves of manganese, most of which are exploited in Gabon and Ghana, and also undeveloped reserves in Angola, Burkina Faso, Côte d'Ivoire, Togo, and Zaire. Africa alone accounts for about 95 percent of the world's known chromite reserves, mainly in Zimbabwe, as well as in Madagascar and Sudan. Africa's share of the world's cobalt reserves is about 33 percent, mostly in Zaire and Zambia, and also Botswana, Uganda, and Zimbabwe. Ten percent of the world's nickel reserves occur in Botswana, Burundi, and Zimbabwe. These alloying metal reserves could possibly give rise to an appreciable gas utilization for the ore processing, provided the distance from ore to gas is reasonable. Available technology for using natural gas for such processing has not been studied in this study, but could be the subject of an interesting feasibility study.

Annex 10. Novel Process for Carbon Black

Source: Kværner Engineering, A/S.

Concept

A10.1 The concept described here entails combustion of natural gas to carbon black and hydrogen in a novel process.

Product Characteristics

Carbon black

Many different qualities, all being close to 100 percent carbon, varying in particle size and other physical properties.

Hydrogen

State at room temperature and ambient pressure	Gas
Properties	Colorless, odorless, explosive
Chemical formula	H_2
Molecular weight	2.016

Market for Carbon Black and Hydrogen

A10.2 World production of carbon black in 1994 reached 6.0 million t. Carbon black may be manufactured on a small scale in Africa, but the United Nations production statistics show no output figures. Seventy percent of world production of carbon black goes into the production of automobile and other vehicle tires. Roughly 20 percent is used in the manufacture of other rubber products, such as hoses, belting, and footwear. The use of carbon black is growing and includes various metallurgical purposes, such as reducing agents, carbon risers, and aluminum electrodes.

A10.3 A number of processes are involved in the manufacture of carbon black, yielding a variety of products (100–150 varieties). Prices also vary significantly for different products, from $600 to $7,000/t. There is a continuing trend toward concentration and consolidation among carbon black producers. Automobile manufacturers have left the business, and it is now dominated by chemical companies for whom carbon black is a core product. Seven major international companies license their carbon black technology worldwide and control 80 percent of world capacity.

A10.4 The world hydrogen market represents nearly 400 billion standard cubic meters of hydrogen per year, representing a value of about $62 billion. Hydrogen is used in the production of ammonia, methanol, and hydrogen peroxide, as well as in iron reduction, iron carbide, combustion engines, and fuel cells.

Plant Size

A10.5 Kværner's carbon black process is designed for 10,000 t/y modules, which may be built together in parallel. The plant size so far recommended by the licenser is 40,000 t/y of carbon black, with the simultaneous production of about 5,000 million scf/y of hydrogen and a quantity of surplus energy (steam or electric power not included in the economic evaluation).

Process

A10.6 Carbon black is usually produced by the partial oxidation or thermal decomposition of hydrocarbon gases or liquids. A number of processes are involved, yielding a variety of products (100–150 products). Ninety-five percent of total world production of carbon black is by the "furnace black" method, a method capable of giving flexibility to adapt to new requirements. However, the furnace black process suffers from several disadvantages, including low feedstock utilization, high emissions and a low-value process gas.

A10.7 A novel process for manufacturing carbon black from natural gas has been developed by Kværner Engineering. A high temperature plasma torch in a reactor converts natural gas directly into a mixture of carbon black and hydrogen. By direct radiation from the plasma torch, as well as convection from the plasma gas (hydrogen), the hydrocarbon feedstock is supplied with sufficient energy to evaporate and reach the pyrolysis temperature. Heat recovery from the exothermic process provides for export of steam or electric power. The pyrolysis of the feedstock is almost 100 percent efficient, resulting in pure products and lower process costs. The process offers great flexibility to produce different qualities of carbon black within the same reactor by varying input parameters. The products from the reactor are then separated in a cyclone system. The carbon black goes to palletizing and bagging, while the hydrogen is compressed to the required consumer pressure.

Feedstock

A10.8 The process consumes about 61,000 scf of natural gas per metric ton of carbon black, and 4,400 kWh of electric power. Annual gas consumption for the recommended 40,000 t/y carbon black plant is thus 2,440 MMscf/y, or 61 bcf over a 25-year lifetime.

Licensers

A10.9 This novel process is licensed by Kværner Engineering, A/S, Oslo, Norway.

Innovation

A10.10 The innovative concept is the high-temperature plasma torch, which converts natural gas directly to carbon black and hydrogen with a 100 percent yield.

Investment Cost

A10.11 NKr 400 million (about \$60 million) for a plant consisting of four 10,000 t/y capacity units is given by the licenser.

Staffing Requirement

A10.12 The staffing requirement is taken to be approximately equal to a 2,500 t/d methanol plant.

Key Results for Carbon Black and Sensitivity Analysis

A10.13 A 40,000 t/y plant has a gas value of as much as \$3.7/MMBtu in the base case. If the product price is reduced by 10 percent and 25 percent, the gas value becomes \$2.5 and \$0.8/MMBtu, respectively. At a localization factor of 1.3, the process can sustain a product price reduction of 15 percent. At localization factors of 1.75 and 2.0, the product price needs to be increased by 5 percent and 15 percent, respectively, to raise the gas value above \$0.5/MMBtu.

Location

A10.14 The carbon black plant should be located as close to the gas source as possible, although the annual gas consumption for the recommended 40,000 t/y carbon black plant is only 2,440 MMscf/year. More important, it must be located adjacent to a hydrogen user, such as a refinery or a metallurgical plant, and if possible near a port or a plant for production of methanol, ammonia or hydrogen peroxide.

Table A10.1 Characteristics and Economic Analysis of Carbon Black

Data item	*Units*	*Large*
Single unit capacity	t/y	40,000
Capex, including offsites	million $	60
Maintenance cost (2.5% of capex)	million $/y	1.5
Operating cost, excluding feed gas	million $/y	6.2
Feed gas consumption	billion scf/y	2.4
Construction period	years	3
Operating period	years	25
Sale revenue	million $/y	27
Gas consumption, 25-year lifetime	tcf	0.06
Gas Values		
Localization factor 1.0 (base case)	$/MMBtu	3.7
Localization factor 1.3	$/MMBtu	2.3
Localization factor 1.5	$/MMBtu	1.4
Localization factor 1.75	$/MMBtu	0.2
Localization factor 2.0	$/MMBtu	-1.0

Note: Sales revenue -

40,000 t/y carbon black at $600/t	$24 million/year
140 million m^3/y hydrogen	$3 million/year
Total	$27 million/year

Annex 11. Combined Carbon Black, Iron Carbide, and Electric Power

Concept

A11.1 This concept combines the processes for using natural gas for iron ore reduction, and for the production of carbon black and hydrogen. At this point in time the concept is essentially an idea, presented as potential utilization of marginalized natural gas in Africa. Data are not available for any economic evaluation of the concept. The idea has been conceived by Dr. Leiv Kolbeinsen at SINTEF, Norway, with permission to quote it in the present study.

Process

A11.2 Natural gas is converted to carbon black and hydrogen, and to surplus energy, by the novel high-temperature plasma torch technology developed by Kværner Engineering. The carbon black process is fed by natural gas and electric power, and produces hydrogen and reduced iron, and some surplus energy in the form of steam or electric power.

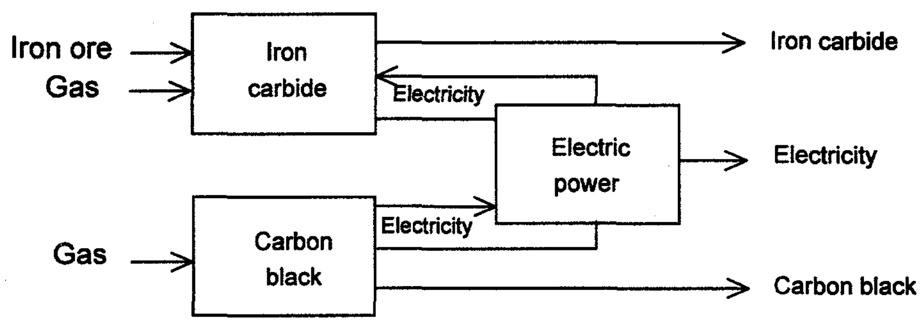
A11.3 Iron carbide has been recommended for the form of reduced iron to be produced. This is due to its resistance to oxidation, to which DRI is prone, and because the higher carbon content of iron carbide may make the iron use more versatile, including its use as a feedstock for cast iron.

A11.4 Carbon black is pelletized, packed, and shipped to the market, and the hydrogen is fed partly to the iron carbide reactor as a reducing agent, and partly to the otherwise gas-fired electric power plant.

A11.5 The iron carbide plant is fed by iron ore fines, natural gas, and electric power, as well as hydrogen from the carbon black plant, and produces iron carbide for storage and export, and a mixture of carbon monoxide (CO) and hydrogen fed to the power plant. The power plant is fueled by off-gases from the carbon black and iron carbide plants, and produces electric power, mainly for export, and also for use in the carbon black and iron carbide plants.

A11.6 This is a highly integrated process with a carefully balanced material and energy flow as shown in Figure A11.1. The advantage is optimal integration of all material and energy flows and thus high energy efficiency. A potential disadvantage is that on account of the high degree of integration, all the three main units need to run simultaneously. In particular, failure of one unit may mean that the other two units will also have to be shut down.

Figure A11.1 Combined Carbon Black, Iron Carbide, and Electric Power



A11.7 Data for the economic evaluation of a full-scale plant are not yet available. Hence no conclusion may be drawn on the gas value, or general viability.

A11.8 Main material and energy requirements and outputs are given below, albeit subject to further optimization:

Input:	Iron ore	500,000 t/y
	Natural gas	9,750 million scf/y, 245 bcf in 25 years
Output:	Iron carbide	335,000 t/y
	Carbon black	122,000 t/y
	Electric power	125 million kWh/y, about 15 MW installed

Location

A11.9 With respect to the plant location, it should be close to the main feedstocks, which are iron ore and natural gas. The export products, iron carbide and carbon black, are easy to transport to their markets, and electric power can go into an existing electricity distribution system. It might be worthwhile to study this concept further for specific locations in Africa.

Annex 12. Bioproteins

Concept

A12.1 The concept discussed here is to use natural gas as a feed for a bacterium, which will convert it to proteins, suitable for food in poultry, fish farming, and other uses. A full-scale plant for such a process is being built by Statoil in western Norway. The data needed for an economic evaluation are not available; consequently, only a brief qualitative presentation is given.

A12.2 Producing proteins by the bacterial action on hydrocarbons, such as naphtha or natural gas, is not a new idea. The former Soviet Union produced 2 million t/y of "monocell proteins." An ICI plant in the United Kingdom produces 75,000 t/d from natural gas.

A12.3 Statoil, in cooperation with their partly owned subsidiary Dansk Bioprotein, has developed a new method, and a new bacterium, *Methylococcus capsulatus*, which produces high-quality proteins from natural gas. EU approval for using the product as animal and fish food has been granted. Some key statistics are given below.

Capacity	10,000 t/y proteins
Capex	$30–45 million
Gas consumption	90,000 scf/t
Market price	$700–5,000/t, depending on type and quality
Uses	Feed for salmon, cattle, chickens, pets
	Adhesives
	Savory for human food
	Protein additives

A12.4 Further data for the project are not available at present, nor has it been possible to consider the potential viability of bioproteins (of any type or description) for use in Africa. This would require a study of the balance of the flow, availability, and price of human food versus animal food in specifically defined geographic regions in Africa, and the potential for trade between regions.

Annex 13. Ranking of Projects

A13.1 All the processes evaluated in this report are ranked in order of decreasing gas value in Table A13.1. A localization factor of 1.3 is applied as a representative, if not minimal, addition to U.S. Gulf Coast capex in Sub-Saharan Africa.

Table A13.1 Ranking of Projects by Gas Value
Localization Factor of 1.3

Type of production	*Daily production*	*Annual revenue (MM$)*	*Capex (MM$)*	*Annual gas consumption (bcf)*	*Life time gas consumption (tcf)*	*Gas value ($/MMBtu)*
Iron reduction ("New DR")	2,900 t	150	300	12	0.3	2.9
Carbon black	120 t	27	78	2.4	0.06	2.3
Dimethyl ether	4,300 t	280	680	65	1.6	2.2
Iron reduction Midrex	2,900 t	150	290	11	0.3	1.9
Dimethyl ether	1,800 t	120	360	27	0.7	1.6
Methanol	2,500t	120	390	27	0.7	1.4
Methanol offshore	1,500 t	74	230	16	0.4	1.0
GTO	2,400 t $C_2^=$[a]	580	1,900	120	3.0	0.9
Ammonia	1,800 t	100	360	20	0.5	0.9
Methanol	1,500 t	74	280	16	0.4	0.7
Synthetic fuel	20,000 bbl	150	610	68	1.7	0.2
Methanol offshore	900 t	44	140	9.8	0.2	0.1
GTO	1,500 t $C_2^=$	380	1,500	80	2.0	0.1
Ammonia	1,000 t	56	250	11	0.3	-0.1
GTO	1,200 t $C_2^=$	290	1,200	61	1.5	-0.2
Synthetic fuel	10,000 bbl	75	390	34	0.9	-0.4
Methanol offshore	600 t	30	130	6.5	0.2	-0.5
Ammonia & urea	3,100 t	150	670	23	0.6	-0.5
Syncrude, FPSO	10,000 bbl	54	330	34	0.9	-0.7
Methanol	600 t	30	150	6.5	0.2	-0.8
Synthetic fuel	5,000 bbl	37	250	17	0.4	-1.2
Syncrude, FPSO	5,000 bbl	27	210	17	0.4	-1.5
Ammonia & urea	1,700 t	86	460	13	0.3	-2.3

Note: FPSO = floating, production, storage, and off-loading.
a. $C_2^=$ ≡ ethylene

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
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
	Project of Energy Efficiency in Buildings (English)	09/95	175/95

Region/Country	*Activity/Report Title*	*Date*	*Number*
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

Region/Country	*Activity/Report Title*	*Date*	*Number*
Mauritius	Bagasse Power Potential (English)	10/87	077/87
	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

Region/Country	*Activity/Report Title*	*Date*	*Number*
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
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
Fiji	Energy Assessment (English)	06/83	4462-FIJ
Indonesia	Energy Assessment (English)	11/81	3543-IND
	Status Report (English)	09/84	022/84
	Power Generation Efficiency Study (English)	02/86	050/86

Region/Country	***Activity/Report Title***	***Date***	***Number***
Indonesia	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
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
	Small Scale Uses of Gas Prefeasibility Study (English)	12/88	--

Region/Country	*Activity/Report Title*	*Date*	*Number*
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
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
Portugal	Energy Assessment (English)	04/84	4824-PO
Romania	Natural Gas Development Strategy (English)	12/96	192/96
Turkey	Energy Assessment (English)	03/83	3877-TU

MIDDLE EAST AND NORTH AFRICA (MNA)

Arab Republic of Egypt	Energy Assessment (English)	10/96	189/96
Morocco	Energy Assessment (English and French)	03/84	4157-MOR
	Status Report (English and French)	01/86	048/86
	Energy Sector Institutional Development Study (English and French)	07/95	173/95
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
	Energy Efficiency Improvement in the Fertilizer Sector (English)	06/90	115/90

Region/Country	*Activity/Report Title*	*Date*	*Number*
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
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
	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	--

Region/Country	*Activity/Report Title*	*Date*	*Number*
Ecuador	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
Saint Lucia	Energy Assessment (English)	09/84	5111-SLU
St. Vincent and the Grenadines	Energy Assessment (English)	09/84	5103-STV
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

Region/Country	*Activity/Report Title*	*Date*	*Number*
	GLOBAL (Continuation)		
	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

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