OCCASION

This publication has been made available to the public on the occasion of the 50th anniversary of the United Nations Industrial Development Organisation.

DISCLAIMER

This document has been produced without formal United Nations editing. The designations employed and the presentation of the material in this document do not imply the expression of any opinion whatsoever on the part of the Secretariat of the United Nations Industrial Development Organization (UNIDO) concerning the legal status of any country, territory, city or area or of its authorities, or concerning the delimitation of its frontiers or boundaries, or its economic system or degree of development. Designations such as "developed", "industrialized" and "developing" are intended for statistical convenience and do not necessarily express a judgment about the stage reached by a particular country or area in the development process. Mention of firm names or commercial products does not constitute an endorsement by UNIDO.

FAIR USE POLICY

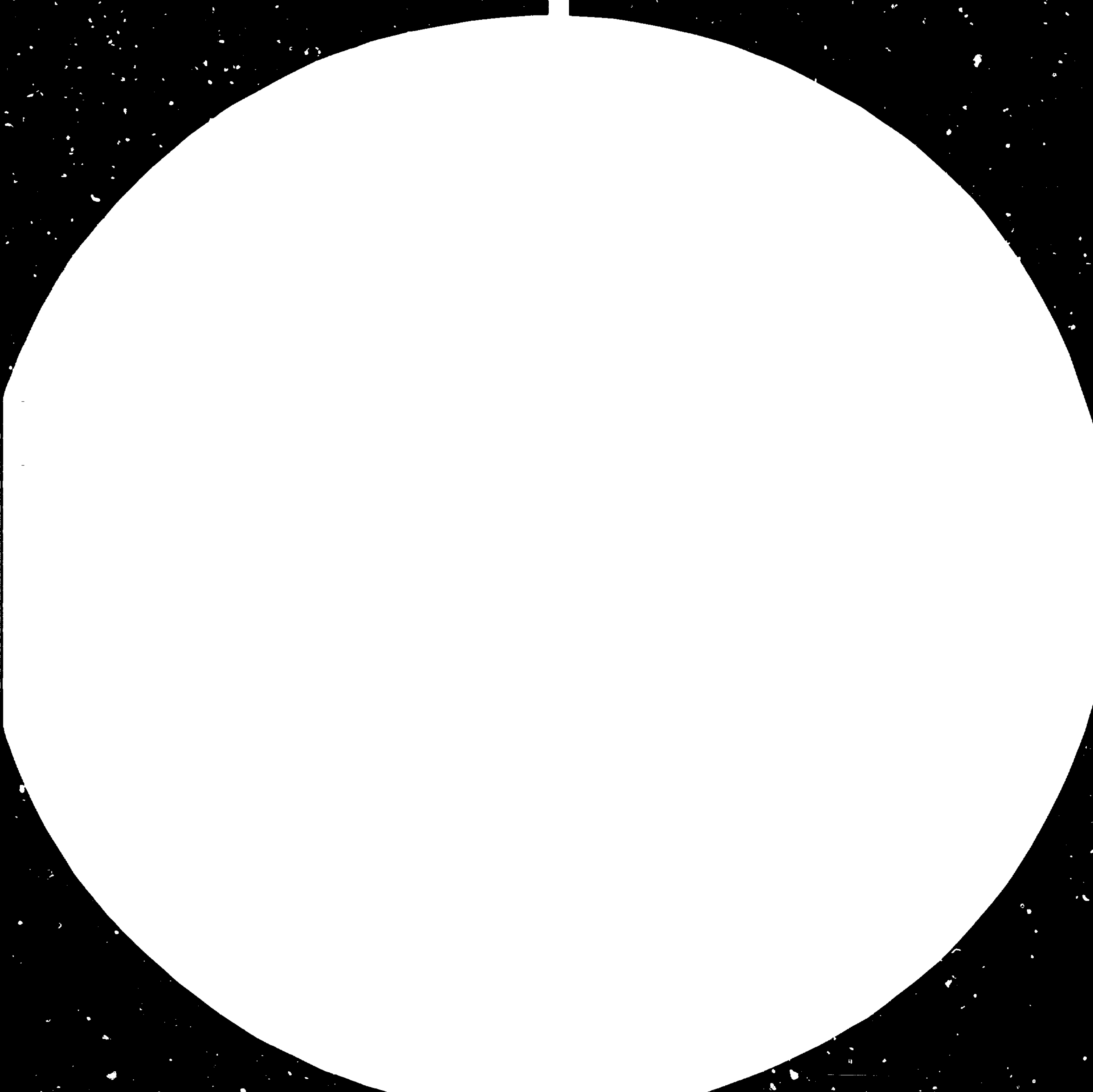
Any part of this publication may be quoted and referenced for educational and research purposes without additional permission from UNIDO. However, those who make use of quoting and referencing this publication are requested to follow the Fair Use Policy of giving due credit to UNIDO.

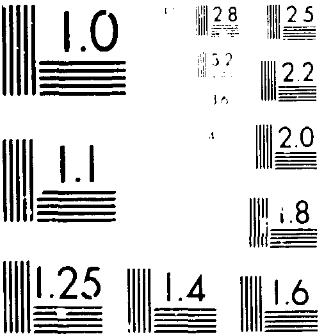
CONTACT

Please contact publications@unido.org for further information concerning UNIDO publications.

For more information about UNIDO, please visit us at www.unido.org

UNITED NATIONS INDUSTRIAL DEVELOPMENT ORGANIZATION
Vienna International Centre, P.O. Box 300, 1400 Vienna, Austria
Tel: (+43-1) 26026-0 · www.unido.org · unido@unido.org




1.0
2.8
2.5
3.2
2.2
3.6
4
2.0
1.1
1.8
1.25
1.4
1.6

10527

Distr.
LIMITED

UNIDO/PC.11
20 July 1981

ENGLISH

UNITED NATIONS INDUSTRIAL
DEVELOPMENT ORGANIZATION

THE INDUSTRIAL USES OF ASSOCIATED GAS.

A Joint Study

by

UNITED NATIONS INDUSTRIAL DEVELOPMENT ORGANIZATION

in co-operation with

GULF ORGANIZATION FOR INDUSTRIAL CONSULTING

30 April 1981

001.[illegible]

V.81-27672

CONTENTS

FIGURES

Page

TABLES

Definitions, Abbreviations and Explanatory notes

Definitions

Associated gas	Natural gas produced in conjunction with oil production.
Non-associated gas	Natural gas produced from fields or domes independent of oil production.
Natural gas	Associated plus non-associated gas including methane, natural gas liquids and non-hydrocarbons (water, carbon dioxide, etc.).
Flared gas	Natural gas that is burned rather than utilized.
LPG	Liquefied petroleum gas - propane (C_3) and butane (C_4).
LNG	Liquefied natural gas excluding non-hydrocarbons; composition depends on pretreatment to remove LPG and/or condensates.
NGL	Natural gas liquids - all natural gas components excluding methane, ethane and non-hydrocarbons.
Condensates	Heavier fractions in natural gas liquids (C_{5+})

Abbreviations

Organizations

UNIDO	United Nations Industrial Development Organization
GOIC	Gulf Organization for Industrial Consulting
OAPEC	Organization of Arab Petroleum Exporting Countries
OECD	Organization for Economic Co-operation and Development
OPEC	Organization of Petroleum Exporting Countries
ECWA	Economic Commission for West Asia, United Nations

Economic and commercial terms

GDP	gross domestic product
GNP	gross national product
R and D	research and development
DC	developing country
IC	industrialized country
OPDC	oil-producing developing country

Technical abbreviations

billion	10^9 or 1,000,000,000 (sign, G; prefix giga)
trillion	10^{12} or 1,000,000,000,000 (sign, T; prefix tera)
bbl	barrel
b/d	barrels per day
t/a	tons per annum
cu ft	cubic foot
cu m	cubic metre
kcal	kilocalorie
Gcal	million kilocalorie
Btu	British thermal unit
l	litre

Equivalents

1 kwh = 3,412 Btu = 860 kcal
1 bbl = 0.159 cu m
1 cu m = 35.315 cu ft

Approximate thermal equivalents[a]

1 ton LNG = 8.9 bbl crude oil (1.2 tons)
= 2.2 cu m liquid (77 cu ft, 14 bbl)
= 1400 cu m gas (50,000 cu ft)

1 billion cu m natural gas = 0.04 trillion cu ft (gas)
= 890,000 ton crude oil
= 6.56 million bbl crude oil

1 million cu m natural gas = 35.3 million cu ft (gas)
= 890 ton crude oil
= 6,560 bbl crude oil

1 billion cu m natural gas per year = 100 million cu ft gas per day
= 17,800 bbl LNG per day
= 27,200 bbl LNG per day

1 million cu m natural gas per year = 14 billion cu ft gas per year
= 325,000 ton crude oil per day
= 265,000 ton LNG per year

---

a/ assuming a gross calorific value of 8600 kcal/cu m for natural gas

Explanatory notes

References to dollars ($) are to United States dollars.

Annual rates of growth or change refer to annual compound rates, unless otherwise stated.

A full stop (.) is used to indicate decimals.

A comma (,) is used to distinguish thousands and millions.

A slash (/) is used to indicate "per", for example t/a = tons per annum.

A dash between dates (for example 1979-1989) indicates the full period, including the beginning and ending years.

The following notes apply only to the tables:

Three dots (...) indicate that data are not available or are not separately reported.

A dash (-) indicates that the amount is nil or negligible.

A blank indicates that the item is not applicable.

Totals may not add precisely because of rounding.

The description and classification of countries and territories in this paper and the arrangement of the material do not imply the expression of any opinion whatsoever on the part of the secretariat of UNIDO concerning the legal status of any country, territory, city or area, or to its authorities, or concerning the delimitation of their frontiers or boundaries, or regarding their economic system or degree of development.

Mention of company names and commercial products does not imply the endorsement of the United Nations Industrial Development Organization (UNIDO).

PREFACE

The first UNIDO Consultation on the Petrochemical Industry held in Mexico City in March 1979 noted that many of the oil-producing developing countries produced large quantities of associated gas and that 100 billion cu m of this gas (equal to well over 2 billion barrels of oil per day) were flared each year. The Consultation therefore recommended that:

> UNIDO should make a detailed study of the associated gas that is presently flared in oil-producing developing countries in order to give a clear picture of the advantages of setting up economic projects to use these wasted resources.

To implement the study, UNIDO worked initially with both OAPEC and GOIC. At their suggestion, the scope of the project was extended to include selected energy-intensive industrial uses of associated gas in addition to fertilizer and petrochemical uses. It was further suggested that the study examine industrial uses of natural gas in the context of an overall plan for the optimal utilization of gas. A Progress Report was prepared in co-operation with OAPEC and GOIC for presentation to the OAPEC Symposium on the Ideal Utilization of Natural Gas held in Algiers in June 1980.

The study was completed by UNIDO and GOIC in April 1981 for presentation to the Second Consultation on the Petrochemical Industry convened by UNIDO in Istanbul, Turkey, in June 1981.

Part One of this final report examines the present situation of associated gas in 18 oil-producing countries[1/] that together account for a major part of the natural gas that is flared.

Chapter I looks at the availability of hydrocarbons by region and the broad areas of utilization—reinjection, direct export, local industries etc. Gas availability data is based on information collected from official and published sources. In this connexion it should be noticed, however, that the numbers are only approximate: associated and non-associated gas are not always clearly distinguished in the world statistics. This is followed

---

[1/] Algeria, Bahrain, Brunei, Indonesia, Iran, Iraq, Kuwait, Libyan Arab Jamahiriya, Malaysia, Mexico, Nigeria, Oman, Qatar, Saudi Arabia, Syrian Arab Republic, Trinidad and Tobago, United Arab Emirates and by a section on gas composition and the economics of gas processing to recover the individual components. (Gas processing is discussed in more detail in annex I).

In chapter II the main uses of associated gas are analyzed in more detail, focussing on applications where gas is a raw material (petrochemicals, fertilizers, sponge iron) and where it is used an an energy source (LNG, LPG and power generation for aluminium). The progress in these product areas being made by the 18 countries is summarized, and the individual country reports presented in annex II.

Chapter III outlines the criteria used for selecting products to utilize flared gas and why nine potential products were selected for further study: ethylene, ethylene oxide, ethylene glycol, low-density polyethylene (LDPE), high-density polyethylene (HDPE), methanol, ammonia/urea, aluminium and sponge iron.

In Part Two (chapter IV), the world market situation for the selected products is assessed in terms of the supply and demand through to 1990. The outlook for LNG and LPG is included at this point —LNG for comparison as an alternative export strategy, and LPG because its recovery and export complements the industrial uses based on methane and ethane.

Part Three examines the prospects for establishing competitive production facilities in representative developing countries in the Middle East and Latin America. Their comparative advantage is assessed on the basis of production and transportation costs involved in reaching markets in Europe and North America.

The study is concluded in Part Four with recommendations concerning technology transfer and market access for the developing countries, and the general need for more co-operation between developed and developing countries.

The UNIDO Secretariat gratefully acknowledges the contributions and assistance of CAPEC, in the initial stages, and GOIC in participating in the study and in the preparation of the report. UNIDO alone accepts responsibility for the final draft and any errors and omissions it may contain.

SUMMARY AND CONCLUSIONS

1. In 1978 the global loss of associated gas in the practice of flaring in the 18 developing countries studied, amounted to some 400 million cu m/d. This was equivalent to 2.62 million b/d of crude oil, i.e. over 8 per cent of crude oil production, and worth $ 94 billion at today's prices. Harnessing this wasted resource would have added over 40 per cent to the combined gas production of these countries.

2. Rising world gas prices and the developing countries' increasing control over their oil and gas resources in the early 1970s lead to plans for increasing utilization of associated gas - at first by means of liquefaction to recover LPG or produce LNG for export, then as the raw material for petrochemical and energy-intensive uses. These plans took longer than expected to realize, but by 1985 the output in nine product areas is estimated as follows:

Product	OPDC Output (1985) million t/a	Per cent World Capacity %
Ethylene	6.25	10.5
LDPE	1.84	9.4
HDPE	0.76	7.6
PVC	1.44	7.6
Ammonia	16.99	15.4
Methanol	4.62	18.3
Aluminium	1.42	5.0
Sponge iron	27.56	2.8

Only in three product areas - ethylene, ammonia and methanol - will oil-producing developing countries' output exceed 10 per cent.

3. Analyzing the individual strategies of the 18 countries, five motives for industrialization can be identified:

- self-sufficiency in petrochemicals;
- establishment of an export-oriented industry;

- oil conservation, boosting oil exports;
- diversification of income sources;
- elimination of political objections to flaring.

4. Energy export strategies relating to associated gas emphasized LPG rather than LNG or pipeline gas during the 1970s. Improving world prices for LNG and pipeline gas may switch the balance the other way in the future.

5. Present plans for industrial and energy utilization will consume more gas than available from projected oil supplies in Algeria, Bahrain, Iran, Kuwait, the Libyan Arab Jamahiriya, Mexico, Nigeria, Qatar, Saudi Arabia, UAE and Venezuela. In Brunei, Oman and Trinidad and Tobago further action is needed to dispose of a clear surplus. In many countries considerable investment in collection and treatment facilities would be needed to permit use of associated gas in preference to non-associated supplies.

6. Many developing country plans involve using associated gas for its fuel value, e.g. in power stations, rather than the chemical value of its components. This leaves considerable scope for further development of petrochemical activities based on the ethane content.

7. The global impact of present OPDC plans on world industrial capacity through to the mid-1980s is modest—less than 10 per cent of total capacity in all products except methanol and ammonia where it might reach 18 and 12 per cent respectively. All forecast increases could therefore be absorbed without difficulty in world markets.

8. The world supply and demand outlook influencing gas-based petrochemical production indicates the need for the following plants to be built between 1984 and 1990: ethylene, 18 units (500,000 t/a each); LDPE, 32 units (200,000 t/a); HDPE, 39 units (75,000 t/a) and PVC, 26 (250,000 t/a). Nearly half these will have to be built to meet demand arising in the Third World itself. Given their favourable feedstock position there is scope for many more to be built by the oil producing developing countries in order to supply developed regions.

9. Methanol—selected for special study because of its impending fuel and chemical uses—is conservatively forecast to move from a global surplus of 900,000 t/a in 1983 to a broadly balanced position in 1990 with demand in the region of 23 million t/a. To achieve this capacity build-up two large production units (2,500 t/d) in Latin America, two in Asian developing countries, and three in Africa/Middle East could be based on associated gas. If fuel uses for methanol grow rapidly, however, both demand and the number of plants required could be doubled.

10. In fertilizers, the demand analysis indicates a requirement for an additional 12 million tons N capacity between 1984 and 1990. Thus the expanding market alone is equivalent to 44 units with 1000 t/d capacity each.

11. Sponge iron demand is determined by the market for scrap steel, which in turn reflects the health of the steel industry in general and the growth rate in electric furnace steel in particular. The long-term outlook is favoured by reduced availability of good quality steel scrap. In the meantime, developing countries are advised to gear both sponge iron and steel output to cover domestic or local regional demand.

12. Primary aluminium consumption is forecast to reach 19.9 million tons in 1985, 24.6 million tons in 1990 and 29.5 million tons in 1995. Between 1985 and 1995 some 60 to 70 smelters each with a capacity of 150,000 t/a would be needed to meet this demand assuming a GNP growth of 3 per cent annually. Given the general reappraisal of the industry's energy position, many of these plants could be built to use electric power from gas turbines fuelled with low-cost associated gas.

13. LNG and LPG: LNG and pipeline gas consumption is forecast to reach 253 million cu m in the mid-1980s and 373 million cu m in 1990. Depending on the eventual contribution of pipeline gas - which would pre-empt supplies from Algeria, for example, demand is sufficient to justify between 20 and 32 new LNG units each producing 7 million cu m/d. The outlook for LPG inputs depends largely on price relative to other energy sources. High prices will prevent penetration of price sensitive but high growth markets in industrialized countries, limiting exports to 34 million tons in the mid-1980s. Lower prices could increase international demand to 47 million tons.

14. A comparison of net production cost for eleven products - ethylene, ethylene oxide, ethylene glycol, HDPE, LDPE, methanol, ammonia, urea, sponge iron, steel, aluminium - based on associated gas in developing countries - and ethane, natural gas or naphtha in developed countries, showed all could be manufactured more cheaply in Mexico and the Arabian Gulf than in the United States and the Federal Republic of Germany. Inclusion of shipping costs to deliver these products to the United States and North and South Europe indicate that developing country production would be able to compete with broad margins against local products in the three developed country markets.

15. Long-term competitivity will be determined by current R and D efforts aimed at alternative feedstocks. Projects coming to fruition in the 1990s include synthesis technology ——modern versions of Foscher-Tropsch, hydroformylation and carbonylation—— crude and heavy gas oil cracking, natural gas from deep formations, and coal-based synthesis gas.

16. In addition to basic competitiveness, a second essential ingredient for successful entry into world markets is co-operation with developed country partners. This could take the form of long-term supply arrangements, product specialization and exchange agreements, jobbing contracts and agency sales agreements. It is recognized that financial and fiscal incentives may be necessary to encourage such co-operation. This can easily be justified in terms of the skills and experience acquired under co-operation arrangements.

17. Such North-South co-operation has mutual advantages. Traditional producers and consumers gain access to new supplies at reasonable costs and with minimum disturbance to existing price and marketing arrangements, i.e. orderly marketing is preserved. The newer, gas-based producers gain access to the best technology and can sell in traditional markets while moving quickly up the learning curves for plant operation, business management and international marketing.

18. While North-South co-operation would focus on primary and secondary derivative petrochemicals, for example, South-South (co-operation between developing countries) would be needed for fertilizers, the main market for which is other developing countries. OPDC co-operation with both groups would be needed in the case of petrochemical end products such as plastics and resins.

PART ONE

THE PRESENT SITUATION

In an energy-short world any flaring of gas is already recognized as a waste, not only for the country doing it but also for the major energy-consuming countries. Part One therefore assesses the present situation of associated gas in developing countries in terms of the amount produced, the proportion wasted by flaring, and the significance of these losses to the individual countries. Current consumption in the form of gas for reinjection, energy exports and local consumption by the process industries, e.g. petrochemicals, sponge iron and aluminium production, is analyzed and current prospects are estimated. These data suggest the need for a development strategy featuring three aspects: reinjection, direct exports and local consumption. The main factors influencing these applications are examined, current strategies of individual countries are evaluated, and a short list of products compiled for further study.

Chapter I

Gas availability and current uses

Associated gas: its origins and why it is flared

Associated gas takes its name from the fact that it is produced in association with crude oil. While still underground the associated form remains dissolved in the surrounding oil due to pressure. Released at the well-head when the pressure drops, it is flared there as a safety measure, failing any alternative use.

Flared gas was variously known to early civilizations as the "eternal flames", the "leaping fiery furnace" and the "burning springs". Ignited by lightning, and burning through the centuries, natural gas seepages were documented by the Greeks and Egyptians; in the Baku area of the USSR, gas flares existed from pre-Christian times. As early as A.D. 200 the Chinese transported natural gas through simple pipelines made of hollowed bamboo logs.[1]

The utilization of associated gas in modern times developed most rapidly in the United States where, following the discovery of oil in the early 1860s, it was used as fuel in a number of Pennsylvania towns. By 1890 there were already 27,000 miles of gas transmission piping in the United States. The development of welded steel pipelines in the 1920s enabled natural gas to be distributed over still greater distances. Today transcontinental pipelines totaling over 500,000 miles in length are in operation.[2]

In a more recent development natural gas is liquefied by refrigeration and transported by sea. The development of LNG tankers, pioneered by the United States and the United Kingdom in 1959[3] and introduced commercially by Algeria, France and the United Kingdom in 1963, brought to countries with surpluses the possibility of selling natural gas to the centres of population and industry in Europe, Japan and North America.

Transport of gas by pipeline in generally still preferred to liquefaction where it is economically and politically feasible. The successful completion of a pipeline from Algeria to Italy under the Mediterranean and off-shore gas pipelines elsewhere may well be followed

---

[1] E.N. Tiratsoo, Natural Gas, Scientific Press, London 1967.

[2] "Reassessment of natural gas prospects", United Nations, E/C.7/106, 1929, p. 5.

[3] M.H.W. Peebles, Chemical Economy and Engineering Review, April 1980, p. 7.

by a greater interest in sea-bed pipeline projects in the 1980s.

There are thus no technical barriers to the collection and transportation of flared gas. The main economic barrier has been the low price of gas in international markets (in both absolute terms and in relation to the price of oil). Despite high transportation costs of LNG, in order to match energy costs in the receiving country LNG from the first liquefaction plants in Algeria was priced at 30¢/million Btu f.o.b. This proved to be an inadequate incentive for further investment in the expensive plant needed to collect and transport the gas.[4/] Other countries meanwhile started to separate methane and ethane for local conversion into petrochemicals and fertilizers as well as reinjection and liquefying propane and butane for local and export consumption as LPG.

Following large rises in the price of gas in the developed countries and the prospect that further rises will take it at least to parity with oil, the choices are much more complex. At $6.00/million Btu f.o.b., LNG projects would not only give an acceptable investment return but considerable economic rent as well. Petrochemicals and fertilizers, on the other hand, open the way for future earnings when revenues from oil exports for many of the countries begin to dwindle towards the year 2000: experience gained in the 1980s with associated gas can be capitalized on by exploiting other resources in the 1990s, especially non-associated gas reserves when available. Entering the sophisticated world of petrochemicals is not easy, however, and many developing countries will require considerable help if they are to overcome the problems of technology transfer, distribution and marketing.

This study is therefore concerned with the possibilities and problems posed by an industrialization strategy based on associated gas: under what circumstances developing country production of petrochemicals, fertilizers and selected energy-intensive industries is competitive in the oil producing developing countries, what kind of market access problems they face, and how industrial co-operation can be used to improve that access.

[4/] In 1978 when crude oil was selling at $12.70/bbl, LNG liquefaction and regasification costs were estimated at the equivalent of $12/bbl. M.A. Borham, OAPEC

The study focuses particularly on associated gas for one main reason: unlike non-associated gas it cannot be left in the ground for use by future generations. By definition associated gas production levels are geared to those of crude oil production. The more oil produced, the more gas becomes available and it must either be utilized[5] or flared.

Availability of hydrocarbons

In 1978 the 18 oil-producing developing countries considered had a combined oil output averaging 32 million b/d. Their natural gas production totalled 323 billion cu m (884 million cu m/day)—the thermal equivalent of 5.7 million b/d of crude oil i.e. one sixth of crude oil output. Of this, 87 per cent, equal to 4.9 million b/d, was associated gas and just under one half (392 million cu m/day, equal to 2.5 million b/d of crude oil) was lost due to flaring.[6]

The importance of these losses to individual developing countries is evident from table 1 showing their reserves and production levels for oil and gas. At present rates of oil extraction, many oil producers' reserves are sufficient to last for only two or three decades. Failing further discoveries, this indicates that by the year 2020 only Saudi Arabia, Kuwait and the UAE would be left as oil suppliers.

Associated gas will follow of course the same production pattern as crude oil As an alternative to flaring, associated gas can: (1) substitute for crude oil as an export earner; (2) substitute for refined products such as naphtha or fuel oil in the domestic economy, thereby releasing further crude or derivatives for export; (3) assist crude oil recovery by means of reinjection; and (4) through industrial use, pave the way

---

[5] In this study the term "utilization" is used in a broad sense to include energy export uses (LNG and pipeline gas), industrial uses (petrochemicals, fertilizers, sponge iron and aluminium production) and reinjection in the oil fields to assist oil recovery and store for industrial use in future years.

[6] Developing countries are not alone in wasting gas by flaring. In 1978 the United States flared 9.6 million cu m/d, 0.6 percent of production. In Europe, gas flaring increased 59 per cent between 1972 and 1976. See United Nations, E/C.7/100, p. 15.

Table 1

Reserves and production of oil and natural gas by country (1978)

Country	Crude oil			Natural gas			
	Proven reserves[a]	Production[b]	Ratio reserves to production	Dry gas proven reserves[c]	Production		
					Non-associated	Associated[d]	Total[d]
	billion barrels	million bbl/d	years	billion cu m	billion cu m/a	billion cu m/a	billion cu m/a
Algeria	6.30	1.16	15	2970	16.75[e]	15.77[e]	32.52
Bahrain	0.25	0.20	12	100	3.50[e]	1.11[e]	4.61
Brunei	1.48	0.25	16	220	-	12.7	12.7
Indonesia	10.20	1.64	17	1088	11.50[e]	6.71	18.21
Iran	59.00	5.24	31	10700	-	55.15	55.15
Iraq	32.10	2.56	34	790	-	11.00	11.00
Kuwait	66.20	2.13	85	1015	-	11.12	11.12
Libyan Arab Jamahiriya	24.30	1.98	29	695	-	21.24	21.24
Malaysia	2.80	0.21	36	473	-	4.00	4.00
Mexico	16.00	1.21	36	1723	9.69[e]	16.79[e]	26.48
Nigeria	18.20	1.90	26	1140	-	20.43	20.43
Oman	2.50	0.32	21	100	-	2.80	2.80
Qatar	4.00	0.49	22	312	-	4.65	4.65
Saudi Arabia	165.70	8.30	55	2000	-	43.75	43.75
Syria	2.08	0.17	33	50	-	1.60	1.60
Trinidad and Tobago	0.50	0.23	6	240	-	4.50	4.50
U.A.E.	31.32	1.83	47	840	-	13.55	13.55
Venezuela	18.00	2.17	23	1190	-	34.52	34.52
Total 18 countries	460.93	31.99	39 (av)	25651	43.59	281.39	322.83

a/ Source: Oil and Gas Journal, 25 December 1978.

b/ Source: OPEC, Annual Statistical Bulletin, 1978

c/ Natural gas reserve figures obtained from CEDIGAZ "Quelques éléments statistiques concernant la situation du gaz naturel dans le monde en 1978", Paris, April 1979.

d/ Gas production/utilization for OPEC member countries from OPEC op. cit., for non-OPEC countries from CEDIGAZ op. cit.

e/ The breakdown between associated and non-associated gas production for Algeria, Bahrain, Indonesia and Mexico has been estimated by UNIDO, based on information from official sources, CEDIGAZ op. cit., etc.

to a non-oil, gas-based economy when crude oil supplies are exhausted. In this context, when non-associated gas is available, it may be noted that the ratio of reserves to production is much higher—running into several decades even in the case of Algeria where production is well developed.[7]

Table 2

Ratio proven reserves to 1978 production in selected countries[a]

	Oil years	Gas years[b]
Algeria	15	91
Bahrain	12	22
Indonesia	17	60
Iran	31	194
Iraq	34	72
Kuwait	85	91
Mexico	36	65
Saudi Arabia	55	46
Trinidad and Tobago	6	53
Venezuela	10	34

Source: Table 1

a/ Assuming present oil and total gas production levels

b/ Includes consumption of both associated and non-associated gas

The global loss

In an energy-short world all gas flared at the well head is a waste of a valuable resource. The size of that wastage in each producing country during the 1970s is evident in table 3. The developing countries' global loss of around 400 million cu m/day as already noted was thermally equivalent to 2.6 million b/d of crude oil. This loss was broadly equal to removing Iraq, in 1978 the world's second largest producer, from the market. At 1978 oil prices ($12.70/bbl) the revenue loss to these countries was over $33 billion; at today's prices ($36.00/bbl) it would have been worth $94 billion. Comparing these losses to individual countries' oil output(table 4) the largest

---

[7] On a world basis it was estimated in 1978 that gas reserves could sustain prevailing production levels for 50 years. Higher gas prices since then have stimulated the search for new sources, thereby increasing the size of proven resources in some countries severalfold. See United Nations, E/C.7/100, p. 10.

Table 3

Associated gas flared, 1972 to 1978

Country	flared (billion cu m)[a]						Proportion of production (%)[c]	
	1972	1973	1974	1975	1976	1978[b]	1973	1978
Saudi Arabia	22.0	33.0	39.1	29.2	37.4	32.4	86	74
Iran	25.9	28.2	27.7	23.5	27.8	24.0	59	43
Nigeria	16.8	20.5	28.4	18.2	21.1	19.5	98	95
Algeria	8.6	12.5	9.5	7.7	10.6	11.4	58	35
Iraq	6.5	7.5	8.1	8.3	8.8	9.3	86	84
U.A.E.	11.1	14.4	14.2	13.5	16.1	12.8	91	95
Indonesia	2.9	4.2	4.6	3.9	5.3	7.5	84	41
Mexico	4.3	3.7	5.1	5.3	5.2	2.0	...	7
Libyan Arab Jamahiriya	6.2	5.4	2.2	3.0	3.2	4.2	33	20
Kuwait	11.6	9.3	6.1	4.6	4.3	4.2	57	38
Brunei	4.3	3.3	1.9	1.5	1.2	3.9	...	31
Qatar	4.0	4.6	3.8	3.2	3.2	3.3	75	71
Venezuela	14.5	14.9	9.8	4.3	3.0	2.5	30	7
Oman	0.9	0.9	1.0	1.1	1.2	2.4	...	36
Bahrain	...	...	...	...	...	0.9	...	19
Trinidad and tobago	0.8	1.2	1.5	1.7	1.6	...	...	62
Total	143.4	168.6	163.0	129.5	150.0	140.3	63	43

Source: United Nations E/C.7/106

[a] Partly UNFSC estimates; includes all gas not marketed (direct losses, venting, gas to drive turbines).

[b] CEDIGAZ op. cit.

[c] Incl. non-associated gas.

losses are normally found with the largest oil outputs, e.g. Saudi Arabia with 89 million cu m/d, Iran with 66 million cu m/d and Nigeria with 53 million cu m/d. These are also countries where oil production has expanded most rapidly, i.e. output growth outpaced the ability of producers to find uses for the associated gas. Quantities of this size were almost double the capacity of the largest LNG plant of the day and the combined total exceeded the volume of gas entering international trade by way of LNG or pipeline shipment.

One measure of the significance of these losses in petrochemical terms is their equivalent in tons of ammonia and ethylene. If 75 per cent of the flared gas could be used in one or other outlets, world ammonia capacity could be boosted by 150 plants each producing 1000 t/d[8] and ethylene by 10 plants each producing 1.500 t/d [9] This could increase world production by up to 40 and 22 per cent, respectively.

Flaring losses should also be judged in relation to the oil output from which they arose: had the gas been put to good use it would have released a thermally equivalent amount of crude oil (or refined products) for export. In this context the heavy losers were some of the smaller oil producers - Malaysia and Brunei with the equivalent of around 30 per cent table 4 of their oil production, and Trinidad and Nigeria with nearly 20 per cent. One measure of the significance of this ratio is Saudi Arabia's plan to invest $ 4 billion in a gas gathering scheme[10] that could save associated gas up to the equivalent of 7.4 per cent of the country's oil output. By such standards the really efficient gas users in 1978 were Venezuela and Mexico in Latin America and Kuwait, Libya and Syria in the Middle East - all with flared gas losses of the equivalent of less than 5 per cent of their oil output.

As evident from the trends shown in table 4 many oil producing developing countries have long recognized the value of these wasting resources; between 1973 and 1978 most producers cut the ratio of flared gas to gross production substantially. In 1978 many projects were in hand that would reduce the ratio still further. Their different strategies and progress through to 1985 are the subject of the next chapter. Individual country reports are included in annex II.

---

[8] Assuming 50 per cent methane content.

[9] Assuming 10 per cent ethane content.

[10] See annex II.

Table 4

Flared gas losses by country

(1978)

Country	Gas flared million cu m/d	Oil equivalent 1000 b/d	Proportion of oil output %
Saudi Arabia	88.8	582	7.0
Iran	65.7	431	8.2
Nigeria	53.4	350	18.4
UAE	35.15	230	12.6
Algeria	31.2	204	17.6
Iraq	25.5	167	6.5
Indonesia	20.5	135	8.2
Kuwait	11.8	75	3.5
Libyan Arab Jamahiriya	11.5	75	3.8
Brunei	10.7	70	28.0
Malaysia	10.7	70	33.0
Qatar	9.0	59	12.1
Venezuela	6.8	45	2.1
Trinidad and Tobago	7.3	47	20.4
Oman	6.6	43	13.5
Mexico	5.5	36	3.0
Bahrain	2.5	16	8.0
Syria	1.4	9	5.3
Total	404.0	2644	8.2

Source: tables 1 and 2

Current uses of associated gas

In broad terms, the outlets for associated gas are six: reinjection to assist crude oil recovery, energy exports in the form of pipeline gas, LNG (liquefied natural gas) and LPG (liquefied petroleum gas), local uses by the process industries (petrochemicals, fertilizers, sponge iron and aluminium) and others (power generation, cement manufacture, general industrial heating, domestic heating etc.). The breakdown and the amount of gas flared for each of the 18 countries is shown in table 5.

The accuracy[11] of the data does not permit a detailed analysis, but the broad picture is clear:

- the quantity of gas flared or vented far exceeds any individual use made of associated gas;
- the largest single use is reinjection for enhanced crude oil recovery;
- direct exports are relatively few in number, but the individual volumes can be large;
- local consumption by the process industries and others is of the same order of magnitude as reinjection;
- compared to other uses, the consumption by the process industries - the main focus of this study - was small.

A preliminary conclusion from these data is therefore that any strategy for eliminating flared gas should feature three components: reinjection, direct exports and local consumption. Reinjection and energy export policies should take care of the volume aspects; local consumption should be promoted to ensure maximum advantage going to the local economy in the form of raw materials and low-cost energy for industrialization. The optimum mix of these three depends on the nature of the gas (see next section), the quantity available in the long term, and the stage of development of the country concerned. The following sections show how the three strategy components are influenced by two upstream factors—gas composition and the type of gas treatment used in the field.

---

[11] The data are necessary by approximations because of the inadequate distinction between associated and non-associated sources in many countries.

Table 5

Breakdown of current uses for associated gas (1978)

Country	Production a/	Utilization						Vented and Flared
		Reinjection b/	Energy exports			Local consumption		
			Pipeline c/	LNG c/	LPG/NGL d/	Process industries f/	Other g/	
	million cu m/d	million cu m/d	million cu m/d	million cu m/d	million cu m/d	million cu m/d	million cu m/d	million cu m/d
Algeria	89.1 e/	13.9	-	17.5	7.0	2.7	16.8	31.2
Bahrain	12.6	2.7	-	-	8.5	2.3	4.6	2.5
Brunei	34.8	-	-	20.3	-	-	3.3	10.7
Indonesia	49.9	2.7		25.8	-	3.5	...	20.5
Iran	151.1	27.0	25.8	-	1.8	3.0	27.8	65.7
Iraq	30.1	-	-	-	0.4	2.6	1.3	25.5
Kuwait	30.5	1.6	-	-	15.5	1.5	...	11.5
Libyan Arab Jamahiriya	58.2	29.6	-	12.0	6.1	1.6	...	11.5
Malaysia	10.9	-	-	-	-	-	0.2	10.7
Mexico	72.5	1.9	-	-	4.3	11.5	34.6	14.8
Nigeria	56.0	-	-	-	-	-	0.1	55.9
Oman	7.7	-	-	-	-	-	1.1	6.6
Qatar	12.7	-	-	-	1.6	0.3	1.3	9.0
Saudi Arabia	119.9	3.7	-	-	17.9	0.4	9.8	88.1
Syria	4.4	3.3	-	-	...	0.1	...	1.4
Trinidad and Tobago	12.3	-	-	-	...	2.5	2.5	7.3
U.A.E.	37.1	-	-	7.9	3.9	2.6	...	35.2
Venezuela	94.6	47.4	-	-	4.1	13.0	23.3	6.8
Total	864.4	145.0	25.8	86.4	63.1	48.1	...	414.9
	100%	16.4%	2.9%	9.7%	7.1%	5.4%	...	49.1%

a/ From table 1
b/ Source: as for table 1
c/ United Nations E/G.7/106
d/ UNIDO estimate assuming 1.185 million cu m/d per 1000 t/a product
e/ Includes some non-associated gas
f/ Includes petrochemicals, fertilizers, sponge iron and aluminium
g/ By difference; ... indicates some sourcing from non-associated gas supplies; includes power cement uses.

Gas composition and possible uses

When oil reaches the surface, the dissolved gas released comprises a mixture of hydrocarbons ranging from methane (C_1) to butane (C_4) and heavier fractions together with impurities such as CO_2, SO_2, H_2S and N_2. Usual oil field practice is to cool the gas to separate hydrocarbons heavier than C_4 as condensates; unless facilities are installed for recovering the other components, the remainder is either flared or reinjected.

The composition of associated gas differs significantly from that of non-associated gas in the higher level of heavier components—ethane, propane and butane.[11] Associated gas in the Middle East contains only 50 to 55 per cent by volume methane compared to at least 80 per cent and sometimes as much as 100 per cent found in non-associated gas. On average (table 5), associated gas in the Middle East contains between 12 and 18 per cent ethane, between 9 and 12 per cent propane and about 5 per cent butanes. In Mexico, associated gas may contain about 82 per cent methane and 10 per cent ethane, while in Indonesia, both are lower—methane 72 per cent, ethane 6 per cent—due to high carbon dioxide levels.

The significance of these differences is that whereas methane—the main component of non-associated gas—is confined to production of LNG (an export use), fertilizers and methanol (for local use or export) and thermal uses (local use only), ethane is a potentially valuable raw material for local petrochemical production, and the propane/butane fractions can be sold locally or exported as LPG. The optimum use of associated gas therefore depends on finding economic local and export outlets for all the main components: methane, ethane, propane, butane and heavier fractions.[12]

---

[11] In some areas, gas composition varies considerably. This can be a particular problem for the petrochemical consumers relying on components. See

[12] The main uses for products derived from associated gas are discussed in chapter II. For world supply and demand for selected products, see part three, chapters IV to IX.

Table 6

Average composition of associated gas in selected countries
(Volume, per cent)

Country	Qatar	Saudi Arabia	Syria	United Arab Emirates	Indonesia	Mexico
Composition						
Methane	55.49	51.0	54.50	55.66	71.39	32.0
Ethane	13.29	13.5	11.70	16.63	5.64	10.0
Propane	9.69	11.5	8.90	11.65	2.57	2.5
Butanes n-butane	5.63	4.4	6.10	5.41		3.5
C-5 and heavier	4.82	2.1	4.30	3.31	3.59	2.0
Carbon dioxide	7.02	9.7	3.50	5.50	14.51	...
Hydrogen sulphide	2.93	2.2	3.40	0.79	0.01	...
Nitrogen	1.12	0.5	7.20	0.55	0.35	

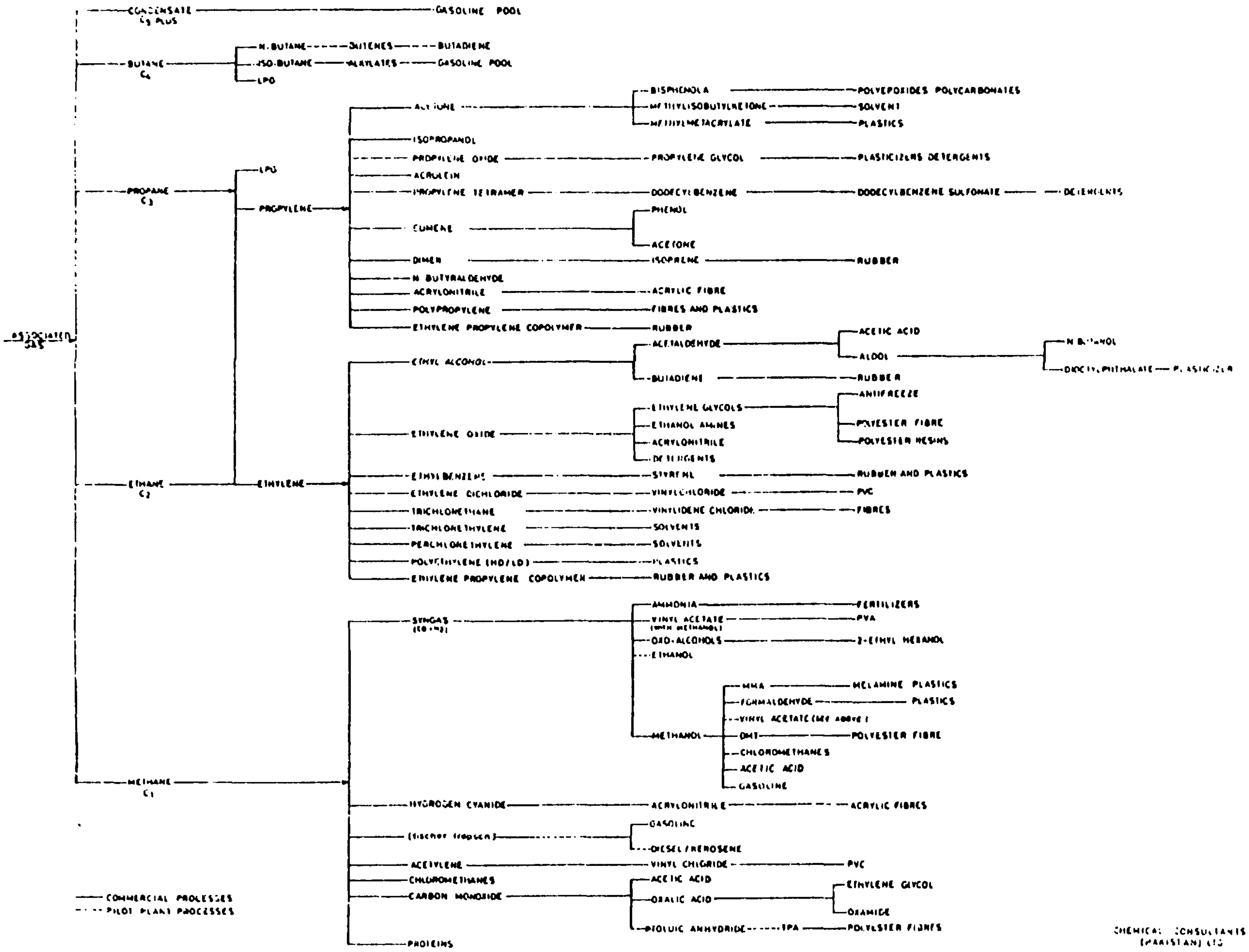
Methane has so far mainly been used for fuel purposes, e.g. power stations and general industrial and domestic heating. Three large-scale consumers of methane are reinjection (after LPG recovery, see next section) and export as pipeline gas or LNG. In the chemical industry, methane presently serves mainly as feedstock for manufacturing ammonia and methanol. More attention is now being paid to technology for converting methane to synthesis gas (mixtures of carbon monoxide and hydrogen) as the basis of new routes to chemical products, gasoline and the middle distillates.[13] Methanol is also attracting attention as a potential basic petrochemical building block on a par with ethylene (see fig. 1). A plant to produce gasoline from methanol is under construction in New Zealand and work on processes for converting methane to ethylene is said to be well advanced.

Ethane is most conveniently cracked to manufacture ethylene; the yields are high and this represents the most economical use. The range of petrochemical products that can be produced from ethylene are also shown in fig. 1.

---

[13] Synthesis gas derived from coal was used for the production of gasoline products in World II (Fischer-Tropsch processes). By the use of modified catalysts, a whole range of products with different numbers of carbon atoms can be produced. A commercial scale plant, mainly for making gasoline (C_5-C_8) exists in South Africa (SASOL process) and the use of such a synthesis for the production of middle distillates (diesel oil and kerosene) is now a commercial possibility. In 1980 the cost of a plant producing 8,000 to 10,000 b/d of middle distillates was estimated by Foster Wheeler at $120 million.

CHEMICAL PRODUCTS FROM ASSOCIATED GAS



Propane can be extracted along with butane in the form of LPG and either exported or used locally. In developed countries, LPG's potential as a chemical feedstock is now more widely considered. Some crackers in the United States and Europe have been adapted to take LPG in order to give feedstock flexibility. When propane is cracked, it yields both ethylene and propylene, the percentage of propylene depending on the severity of cracking. Propane can often be cracked together with ethane and the mixture produces mostly ethylene; only large crackers (producing 200,000 t/a ethylene or more) produce significant quanitities of propylene. Thus, if large quantities of propylene are required, it is better to crack propane alone or a butane-propane mixture. The petrochemical derivatives of propylene are shown in Fig. 1.

Butane is mainly consumed as LPG (see above). Chemically, it comprises a mixture of normal- and iso-isomers, of which iso-butane is the more valuable because it can be converted to iso-butylene. Iso-butylene is the precursor of a number of products including the alkylate required in large quantities for the gasoline pool. A potentially important use for iso-butane is to make MTBE, a gasoline component needed to replace lead in high octane gasoline.

Pentane and heavier fractions are generally separated in the field; the resulting liquid mixture, known as condensates, is either treated and sold as such or mixed with reformed motor gasoline, naphtha or crude oil.

Treatment and processing

Processing of crude gas depends ultimately on the way individual components are to be marketed, but there are two basic approaches - complete liquefaction to make LNG, and partial liquefaction[14] to recover LPG and possibly ethane. As noted, in either case pentane and heavier fractions are generally separated in the field.

With the emergence of LPG in developed countries as a high-value feedstock as well as a fuel—substituting for increasingly expensive naphtha—partial liquefaction is likely to increase in importance. Compared to LNG units, LPG recovery plant (fig. 2) is low in capital cost and, in addition to providing LPG for downstream consumption and export, provides two components streams for possible petrochemical and fertilizer use.[15] Ethane with some methane serves as feedstock for ethylene-based petrochemicals. Methane can be used for ammonia-based fertilizers and for methanol. At some locations, the methane-rich residual gas from an LPG recovery plant can be used for reinjection (see next section).

The operating cost characteristics for an LPG recovery plant are outlined in annex I. This indicates an average recovery cost of $ 80 to $ 100/ton including a 25 per cent pretax return on investment. If the ethane and methane are assumed to have zero value, the average cost of producing the remainder - LPG and natural gasoline - rises to $ 130 to $ 190/ton, i.e. still well below prevailing LPG prices of $ 300/ton.

---

[14] Partial liquefaction can be carried out in one or two stages. Single-stage systems recover components by fractional cooling. Two stage designs, used for example in Saudi Arabia, liquefy everything except methane in the field, and fractionate the resulting liquids in a separate unit. Where LPG recovery is the sole objective, associated gas can also be treated in absorption plants where it is compressed and scrubbed with kerosene. Such units typically recover 90 per cent of the butane but only 35 per cent of the propane and less than 10 per cent of the ethane. They are therefore unsuitable as precursors of petrochemical operations.

[15] For review of processes used in gas liquefaction and fractionation, see for example E.N. Tiratsoo, Natural Gas, London 1976; M. Medici, The Natural Gas Industry, a review of world resources and industrial applications, Newnes-Butterworths, London, 1974.

PROCESSING OF ASSOCIATED GAS

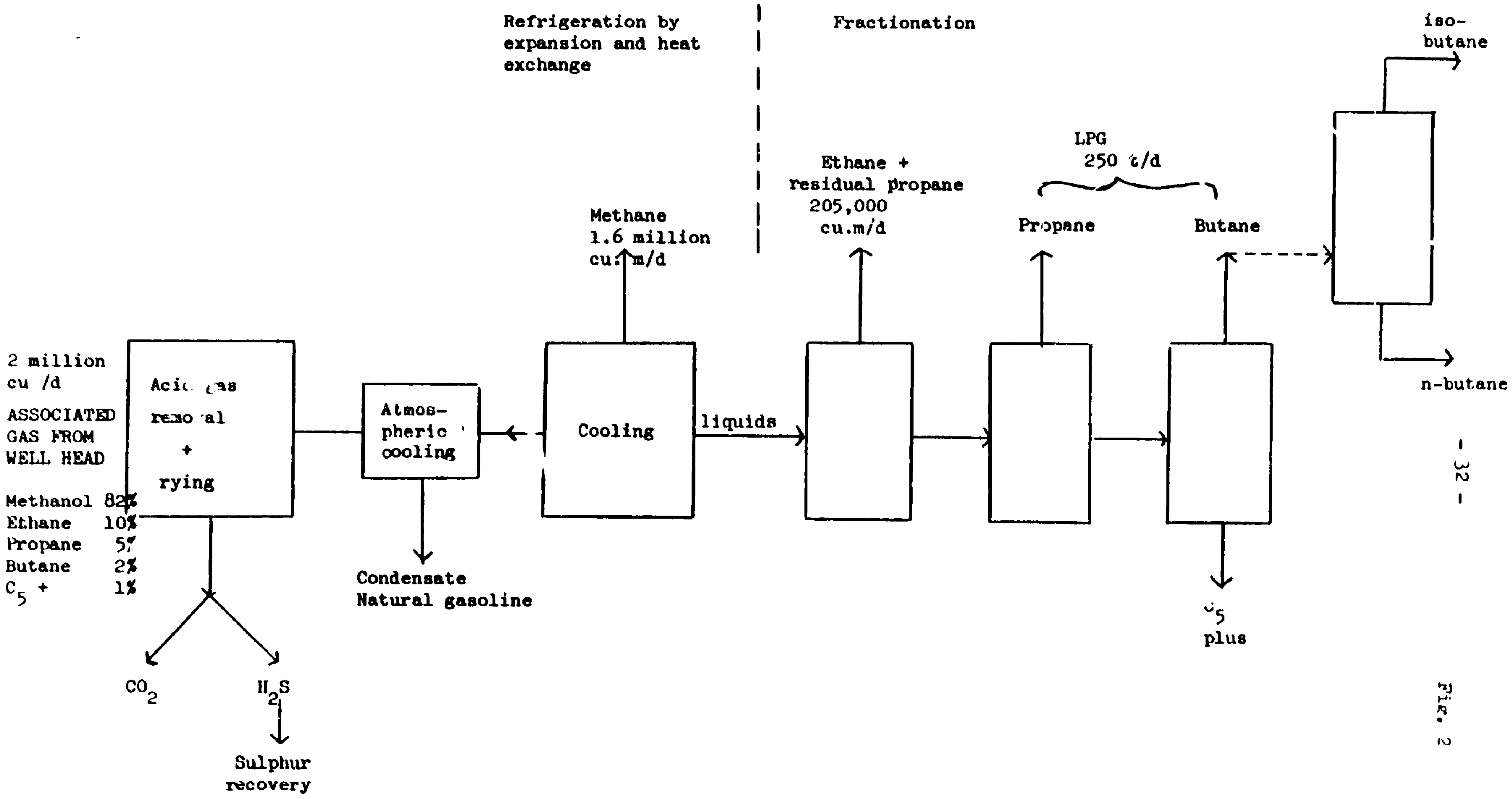


Fig. 2

In practice it does cost something to transport methane and ethane out of a recovery plant to consuming industries. For the purposes of subsequent calculations in the study[16] ethane in 1980 is assigned an arbitrary low value of $ 25/ton. Methane is priced at prevailing market levels for fuel gas.

---

[16] See part three, chapters X and XI.

Chapter II

The main uses of associated gas - 1980 to 1985

As identified in Chapter I, the main uses of associated gas are three—reinjection, industrial uses in the processing industry and energy uses for export, general industry and domestic consumption. The following sections discuss each in more detail and assess the progress being made by the oil-producing developing countries under each heading.

Reinjection - possibilities and limitations

When gas is reinjected[17] into an oil well to maintain the pressure, it partially mixes with the oil, lightens it and speeds or prolongs its recovery. As an outlet for associated gas, the large volumes required already make reinjection an attractive option: between 14 and 60 cu m of gas can be used per barrel of oil recovered. Furthermore, the gas reinjected may eventually be recovered along with the oil.

The problem is that the effectiveness of reinjection depends on the type of well and the type of oil. In certain geological formations, gas reinjection can even be counterproductive. There is a danger of water coning, gas loss due to too rapid increase in gas/oil ratios, and oil loss due to pocket formation. High pressure processes, furthermore, are confined to relatively light crudes, e.g. API gravity of 35 or over, and to reservoirs sufficiently deep for the overlying rock to contain pressures up to 400 atmospheres. The reinjection process can also be expensive, especially in off-shore fields.

Reinjection is nevertheless a way of storing gas underground pending development of suitable markets. This approach might therefore be considered a realistic solution for some countries—especially those lacking the infrastructure and skills needed for using associated gas in industrial projects.

17/ Gas reinjection is one of a number of enhanced recovery methods used in oil production. Other approaches include thermal recovery (steam injection or in situ combustion), miscible flooding (injection of LPG, enriched gas, alcohol, flue gas, nitrogen, carbon dioxide) and chemical flooding (using surfactants, polymers and alkaline chemicals). Gas reinjection requires either the presence of ethane, propane or butane to make the gas miscible with oil at low pressure (100 atm.) or very high pressures. See Scraping the Barrel, Financial Times Management Report, 1980.

The economic and technical limitations in reinjection combined in fact to reduce this use of associated gas from 30 per cent in 1972 to 26 per cent in 1976.[18] Although this was a period when oil production was rising rapidly, i.e. the overall quantity reinjected increased in absolute terms, the trend was to find other uses for the associated gas produced.

Industrial uses of associated gas

After reinjection, the largest outlet for associated gas is direct export in the form of pipeline gas or LNG. These are discussed in the next section and were the first large-scale uses. The interest in industrial applications as an alternative arose partly from demands for industrialization per se, but mainly because the prices for export gas were considered too low to justify the investments involved in liquifaction and long-distance pipelines.

The list of industrial products on which associated gas can be based is very large, even when confining it to products in which gas functions as a raw material rather than an energy source. A selection of those considered most probable in the next two decades (table 7) divides them into four groups: petrochemicals (olefin- and aromatics-based), fertilizers (ammonia-based), methanol (chemical and fuel uses), and metals (sponge iron and ferrosilicon). To this could be added a fifth group - petroprotein - initially based on methanol, later directly on gas-consuming microbes.[19] Table 7 shows over 100 products of which one third are end-products with many more individual members.

The techno-economic and marketing aspects of a representative sample from each group are discussed in detail in Parts Two and Three of this study. The following comments summarize the developing country prospects for the groups as a whole:

---

[18] United Nations, E/C.7/106, p. 15.

[19] Petroproteins were included in the initial studies, see Progress Report, "The Industrial Uses of Associated Gas", UNIDO, 31 May 1980.

Table 7

Possible industrial uses of associated gas

Group I - Petrochemicals excluding methanol (see also Fig. 1)

A. Olefine based: methane, synthesis gas, vinyl acetate, PVA[c]; oxo-alcohols, 2-ethyl dexanol; oxo-alcohols, ethanol and derivatives (see below); methanol[a] and derivatives (see below); hydrogen cyanide, acrylonitrite (see below); gasoline[c]; diesel[c]; kerosene[c]; acetylene, VCM (see below); chloromethanes, carbon monoxode; acetic acid, oxalic acid, ethylene glycol (see below), oxamide; phthalic anhydride, TPA, polyester fibre[c]; proteins[b,c].

Ethane, ethylene[a], ethyl alcohol, acetaldehyde, acetic acid, aldol, n-butanol, dioctylphthalate, plasticizers[c], butadiene[b], rubbers[c], ethylene oxide[a], ethylene glycol[a], antifreeze[c], polyester fibre[c], polyester resin[c], plastics[c]; ethanol amines, acrylonitrile, acrylic fibre[c], detergents[c]; ethylene dichloride, vinyl chloride (VCM)[a,b,e], PVC[a,b,e], trichlorethane; vinylidene chloride; trichlorethylene, solvents[c]; perchlorethylene; high-density polyethylene (HDPE)[a], low-density polyethylene (LDPE)[a], low low-density polyethylene (LLDPE)[a]; ethylene propylene copolymer.

Propane, propylene[b,e], acetone, bisphenol A, epoxy resin[c], polycarbonates[c], methylisobutylketone, methyl methacrylate; isopropanol; propylene oxide; propylene glycol; acrolein; propylene tetramer, dodecylbenzene, dodecylbenzene sulfonate; cumene, phenol; propylene dimer; isoprene; n-butyraldehyde; polypropylene[c]; butane, n-butane[b], butenes; isobutane, alkylates, LPG[a].

B. Aromatics based[d]: ethyl benzene[e], styrene[e], polystyrene[c,d], ABS[c], SAN[c], SBR[c]; carbon black[c].

Group II - Fertilizers

Ammonia[a,c], urea[a], ammonium nitrate[c], ammonia sulphate[c], DAP[c], MAP[c], complex fertilizers[c];

Group III - Methanol

Melamine plastics[c], formaldehyde, vinyl acetate (see above), DMT[e], polyester fibre[e], chloromethane (see above), acetic acid (see above), gasoline.

Group IV - Metals

Sponge iron[a,c], electric furnace steel[c], ferrosilicon[c].

---

[a] Selected for further study, see chapter III.

[b] Selected in Progress Report 1: **"Industrial uses of associated gas"**, paper at the OAPEC Conference on the Ideal Utilization of Natural Gas, Algiers, June 1980.

[c] End product

[d] Aromatics together with associated gas derivative

[e] Included in parallel work: Second World Wide Study of the Petrochemical Industry, UNIDO, June 1981.

Petrochemicals: high but rapidly slowing growth rates for industrialized country demand; opportunities for new entrants to compete both with older, inefficient developed country units and to supply growing demand in developing countries. Petrochemical technology (patent rights and production plant) is easily acquired, except for a few proprietary processes. Investment in petrochemicals requires, however, long lead times and large amounts of capital. Following improvements in world LNG and pipeline gas prices, opportunity costs for associated gas in petrochemicals have risen in recent years, making some products uneconomic and others less profitable. Compared to energy exports, petrochemichals are a small gas consumer. The immediate effect on local employment is small, but where desired, end-products such as plastics and fibres can provide, however, the basis of modern, but relatively labour-intensive industries in the fields of textiles, plastics processing and packaging.

Fertilizers: Forecasts of world ammonia supply and demand indicate a global surplus through to 1983/84,[20] but due to delays in bringing new capacity on stream, this may not happen in practice. Many older liquid feedstock plants in industrialized countries have already shut down for good due to competing imports from new, gas-based units. In the medium and long term, substantial new capacity will be needed to match growing demand in both developed and developing country markets. Much of this will take the form of ammonia/urea combinations. As with petrochemicals, fertilizers are capital- rather than labour-intensive. Local use in agriculture would absorb some of the output, eliminating imports, while offering the basis of product specialization arrangements with producers of complementary products, e.g. phosphate, potassium or mixed fertilizers in exchange for ammonia or urea.

Methanol: The future for methanol is the least certain of the industrialized uses. At worst, new methanol outlets would not develop, in which case there is already too much capacity committed world-wide. At best, new methanol applications in petrochemicals (see table 7), petroprotein, gasoline additives, and fuel uses (see next section) will be realized and methanol would become a commodity chemical as important as ethylene. If demand outstrips supply, methanol prices could rise to a level where local coal-based production is competitive in industrialized country markets.

20/ "Current World Fertilizer Situation and Outlook", FAO,Rome, January 1980.

Metals: Demand for sponge iron relates to the supply and demand for scrap steel suitable for electric furnace steelmaking. In turn, this depends on the health of the world steel industry, which although depressed at present, can be expected to recover by the mid-1980s. Although scrap is traded internationally, sponge iron shipment presents some technical difficulties. In this context, therefore, developing countries should consider sponge iron and steelmaking plant in the first instance to satisfy local or regional demand. Similar considerations would apply to ferrosilicon production.

Energy uses

Energy outlets for associated gas include LNG, LPG, pipeline gas, energy-intensive products and fuel grade methanol. These are divided between local and export uses as follows:

Table 8
Energy uses of associated gas

Domestic/commercial	Local industry	Export
Pipeline gas	LPG	Pipeline gas[a]
LPG	Pipeline gas	LNG[a]
	Energy-intensive products, e.g.	LPG/NGL[a]
	aluminium[a]	Methanol[a]
	magnesium	
	cement[b]	
	electric power	
	desalination	

a/ Selected for further study (see chapters X and XI).
b/ Selected in Progress Report, op.cit.

Local use of pipeline gas for domestic and commercial heating has long been established in industrialized countries, and many developing countries are beginning to follow suit with urban distribution networks. This has the advantage of both developing the local economy and releasing oil products for export. In view of the explosive growth of many cities in developing countries, this may represent large-scale use for gas in the long term; in the short run, however, expansion may be too slow to absorb much flared gas.[21]

---

[21] An Egyptian example illustrates the difficulty of many developing countries with low per capita energy consumption. In 1978, Egypt found that less than 7 per cent of surplus gas could be absorbed by converting the residential/commercial sector from existing fuels. See "Co-operative Energy Assessment Report", joint Egypt/United States study, Cairo, November 1978.

Usually the main immediate local use for pipeline gas is power generation, together with industrial consumers such as the aluminum and cement industry.[22] In contrast to industrialized countries, which have generally been reluctant to use gas in power stations—where its premium properties are lost, developing countries often need power station outlets to justify collection and distribution systems that allow residential/commercial uses to develop later.

Of the four energy-intensive export markets for associated gas, LNG was the largest in volume terms in 1978. As noted, the unfavourable prices for LNG until the early part of 1980 switched attention to other export projects. The prospects for LNG following higher prices in recent months are much improved. At the same time, these prices have also stimulated exploration for non-associated gas, especially in the United States. LNG trade would also be influenced by large-scale production of methanol for fuel use (see below).

NGL products have enjoyed a rapid increase in price due to demand from fuel, transport and petrochemical uses. The premium over low-sulphur residual oil in the industrialized country power station and boiler fuel markets may vanish, however, when all the forecast new capacities in the Middle East come on stream by about 1985.

As with its chemical uses, methanol's future as a fuel is the least certain. Demand will be determined by the relative cost of production, shipping and combustion compared to LNG. These factors are discussed in detail in chapter VI.

---

[22] For a study of cement industry applications of associated gas see Progress Report, op.cit.

Current developing country projects using associated gas

The factors determining the level and form of gas utilization in a particular country are technical, economic and political.

Technical and techno-economic considerations include the gas composition discussed previously, gas availibility and forecast rate of flow from different gas sources, and the minimum economic size of processing and production plant in the location concerned. Purely economic factors are the size of the local market for products that can be made from gas, and possibility of competing with these products in export markets.[23] Political questions—often the most important—concern the whole national strategy for industrialization, whether it should be local- or export-oriented, whether subsidized with low-cost utilities, infrastructural support and investment loans, and whether a large influx of foreign labour is necessary or desirable to operate the plants once built. This is not the place to discuss industrialization *per se*[24] but the need, and therefore the exploitation pattern for associated gas, will clearly be different for a small oil-rich population such as Kuwait and its equal oil-rich neighbour, Iran.

A further factor explaining some of the differences in the progress among the oil producing developing countries is that experience and ability to handle all the marketing aspects. The marketing problem faced by LNG plant operators seeking twenty-year contracts is quite different from those making ammonia where supply contracts are typically for only two or three years.

---

[23] The economic viability of export-oriented gas-based petrochemical, aluminium and steel production is discussed in subsequent chapters.

[24] For two recent examinations of industrial strategy adopted by different developing countries, see "The year 2000 in new perspective", collected background papers, Vol. 6, UNIDO-IOD/337, 1980

They are different again for producers of PVC resin attempting to break into industrialized countries' plastics markets. Some of these problems are discussed in Parts Three and Four of this study.

The different approaches adopted by eighteen countries in utilizing flared gas are summarized in annex II. The sources are either official or published.

Country-to-country differences

In nearly all the eighteen countries considered, gas usage forms an integral part of an overall strategy for industrialization.[25]

Within the context of industrialization, five motives determining the way and extent to which gas is exploited can be identified. They are clearest in the following examples:

+ Progress towards self-sufficiency in petrochemicals—Indonesia, Iran, Mexico;
+ Providing the basis of export-oriented industry—Mexico, Saudi Arabia, Kuwait, Iran, Venezuela;
+ Oil conservation, oil release for additional export, replacement of declining oil reserves—Iraq, Algeria, Qatar, Saudi Arabia, Trinidad and Tobago, UAE, Indonesia;
+ Diversifying income sources—Kuwait, Qatar;
+ Elimination of flaring as political factor per se—Mexico.

Governments that look to direct gas exports as a way to support export earnings while conserving oil supplies may choose between LPG and—where sufficient gas is available—LNG operations. To date only eight countries (table 9) have chosen to pursue this objective with LNG plants—compared to twelve that have selected partial liquefaction route for extracting LPG.

---

[25] In several cases it should be noted that industrialization itself has been reappraised. Algeria has scaled down industrial plans in favor of agriculture, housing and other social goals—at the expense of two LNG projects. In future Saudi Arabia will place more emphasis on social goals in its planning.

Table 9

How developing countries export energy - 1978

LNG[a]	LPG	Pipeline Gas
Abu Dhabi	Abu Dhabi[b]	Iran
Algeria[b]	Algeria[b]	Mexico
Brunei	Bahrain	
Indonesia[b]	Dubai[c]	
Libya	Indonesia	
Malaysia[c]	Iran[b]	
Nigeria[c]	Iraq[b]	
Trinidad and Tobago	Mexico[b]	
	Oman	
	Qatar[b]	
	Saudi Arabia[c]	
	Venezuela[b]	

[a] Depending on composition, LNG units may also export LPG.

[b] Expansion planned.

[c] Planned or under construction.

Two factors explain the preference for LPG: high capital cost and low returns on the first LNG units installed in Algeria, and the superior marketing flexibility offered by LPG products. LPG can be readily sold both to a large number of customers and into chemical as well as thermal uses.

In some cases the simplicity of marketing LNG—once the basic framework is established—may be considered more important, e.g. in Nigeria, pending development of marketing expertise in the country concerned. For the future, however, the new factor is the relatively high value now placed on LNG as a commodity. LNG at oil parity prices or above may give better returns with higher economic rent than hitherto. Ultimately the development of LNG trade depends on the speed at which the distribution system grows. When ships are readily available and liquefaction plants, terminals and regasification plants are in place, liquefaction will gather considerable momentum.

Gasification[26] of the local economy in order to release oil products for export usually goes hand in hand with a policy of industrialization

---

[26] Substitution of gas for bottle gas, heating oil and other energy forms in local industry, commerce and domestic uses.

to improve internal consumption. But as Mexico's experience illustrates, the cost of pipelines and compressors means this is not necessarily a cheap alternative. Under its National Industrial Development Plan, Mexico's domestic use of gas will be boosted by a $1.1 billion investment in compressors and 2,500 km of pipeline to bring gas from Cactus in the south to San Fernando, the northern industrial center. One side-benefit of this project, however, is the closure of number of non-associated gas fields for later use.[27]

The re-injection option has been pursued with most vigour by two countries, Libya and Venezuela. In 1978 both re-injected more than 50 per cent of their available associated gas. This was instrumental in their achievement of flaring rates below 10 per cent of associated gas produced. The only other developing country with a flaring level of this order was Mexico. Mexico's policy of maximum utilization of gas in industrial projects goes hand in hand with a re-injection programme that in late 1970s cut flaring from 17 million to 1.5 million cu m/d, bringing the volume down to 7 per cent of production.

Choice of industrial products

The choice of products for industrial projects based on associated gas (table 10) clearly reflects a combination of local needs and ease of international marketing. By 1985, fifteen of the eighteen countries will be operating ammonia plants, and seven of these plan downstream urea units Fourteen countries are building or planning direct reduction sponge iron plants as the basis of a local steel industry. Aluminium in contrast, has only ten adherents and one, Malaysia, may well switch into iron and steel as a better basis for downstream activities.

Methanol, which like ammonia can use natural gas as feedstock without significant pretreatment, will be produced in ten countries in 1985.

---

[27] Financial Times, 26 May 1980

Table 10

Products selected for gas utilization[a]

Ethylene:	Algeria, Indonesia,[b] Iran,[b] Iraq,[b] Kuwait,[b] Libya,[b] Mexico, Qatar, Saudi Arabia,[b] Venezuela
Low-density Polyethylene:	Algeria, Indonesia,[a] Iran,[b] Iraq,[b] Kuwait,[b] Libya,[b] Mexico, Qatar,[b] Saudi Arabia,[b] Venezuela
High-density Polyethylene:	Indonesia,[b] Iran,[b] Iraq,[b] Mexico, Qatar,[b] Saudi Arabia,[b] Venezuela
P V C:	Algeria, Iran, Iraq,[b] Kuwait,[b] Mexico, Venezuela
Ethylene dichloride:	Iran,[b] Saudi Arabia[b]
V C M:	Indonesia,[b] Mexico, Venezuela
Ethylene oxide/ ethylene glycol:	Indonesia,[b] Kuwait,[b] Saudi Arabia,[b] Mexico,
Styrene:	Mexico, Saudi Arabia,[b] Iran,[b] Kuwait,[b] Libya[b]
Ethyl alcohol	Saudi Arabia[b]
Acetaldehyde:	Mexico
Ammonia:	Algeria, Bahrain,[b] Indonesia, Iran, Iraq, Kuwait, Libya, Malaysia,[b] Nigeria,[b] Qatar, Saudi Arabia,[b] Syria, Trinidad and Tobago, UAE,[b] Venezuela
Urea:	Indonesia, Iran, Iraq, Kuwait, Libya,[b] Malaysia,[b] Nigeria,[b] Saudi Arabia,[b] Trinidad and Tobago,[b] UAE,[b] Venezuela
Methanol:	Algeria, Bahrain, Indonesia,[b] Malaysia,[b] Saudi Arabia,[b] Trinidad and Tobago[b]
Aluminium:	Algeria,[b] Bahrain, Indonesia,[b] Iran, Iraq,[b] Kuwait,[b] Libya,[b] Mexico, Trinidad and Tobago,[b] UAE (Dubai)
Sponge iron:	Bahrain, Indonesia, Iran,[b] Iraq,[b] Libya,[b] Malaysia,[b] Mexico, Oman,[b] Qatar, Saudi Arabia,[b] Syria,[b] Trinidad and Tobago,[b] UAE,[b] Venezuela

---

[a] Excludes power generation, desalination, cement manufacture and general gasification of the economy.

[b] Planned or under construction.

Despite the heavy upstream investment needed for ethane recovery ten countries are also embarking on petrochemical production with large scale ethylene crackers. In downstream plastics, high- and low-density polyethylene, with six countries each, have the edge over PVC with four prospective producers. Four countries are moving into ethylene oxide/ ethylene glycol, and further four will set-up styrene production on the basis of locally available benzene and ethylene.

The estimated capacities for gas-based industrial products in oil producing developing countries is shown in table 11.

Measured in terms of the number and diversity of project, the leading developing countries in 1985 will be Saudi Arabia, Iran, Mexico and Iraq. The least gas-oriented industries will be in Oman and Syria, both with only limited quantities of associated gas, and Nigeria.

For the future, gas re-injection can be expected to increase in importance, growing at the expense of water re-injection where both are technically feasible. Growth will be strongest in countries with partial liquefaction facilities to extract LPG, the lean gas from which can be returned underground.

General assessment

The data available to the secretariat permits at best a crude quantitative assessment of the likely positions in 1985. Apart from realization of plans for LNG, LPG, petrochemicals, fertilizers and other large-scale industrial uses, the reality for each country will also be determined significantly by government decisions on oil production rates and re-injection volume.

Assuming oil production rates at least equal to those in 1980, known industrialization plans will certainly bring down the quantities of gas wasted by flaring. In Algeria, Bahrain, Iran, Kuwait, Libya, Mexico, Nigeria, Qatar, Saudi Arabia, UAE and Venezuela resulting gas demand will be greater than the available supply from associated gas sources. Only in Brunei, Oman, and Trinidad and Tobago will there be a clear surplus that will still be flared unless some action is taken.

Table 11

Gas-based production of petrochemicals, fertilizers and selected industrial products in developing countries (mid-1980s estimates)

(ton/year)

	Ethylene	Low-density Polyethylene	High-density Polyethylene	EDC/VCM or PVC	Styrene	Ammonia	Urea	Methanol[g]	Aluminium	Sponge iron
Algeria	140 000	48 000	-	35 000	-	991 000	278 000	100 000	127 000[b]	800 000[a]
Bahrain	-	-	-	-	-	660 000[a]	-	350 000	120 000	400 000
Brunei	-	-	-	-	-	-	-	-	-	-
Indonesia	300 000[a]	185 000[a]	60 000[a]	110 000	-	2 173 000	3 954 000[b]	400 000	225 000[a]	2 200 000[b]
Iran	325 000[b]	100 000	60 000	40 000	30 000[f]	1 106 000[a]	1 180 000[a]	-	110 000	6 130 000[a]
Iraq	130 000[a]	60 000[a]	30 000[a]	60 000[a]	-	994 000	1 535 000	135 000[a]	120 000[a]	1 935 000[a]
Kuwait	350 000[a]	130 000[a]	-	-	320 000[a]	994 000[b]	1 360 000	-	120 000[a]	-
Libya	-	-	-	-	-	663 000[b]	900 000	330 000	60 000[a]	1 000 000[a]
Malaysia	1 945 000[b][c]	-	-	-	-	380 000[a]	328 000[a]	550 000	100 000[a]	800 000[a]
Mexico	300 000[a]	499 000[b]	200 000[b]	570 000[b][d]	333 000[b]	4 796 000[b]	1 691 000[a]	1 007 000	120 000	4 540 000[a]
Nigeria	-	120 000[a]	60 000[a]	120 000[a]	-	330 000[a]	496 000[a]	-	-	-
Oman	-	-	-	-	-	-	-	-	-	400 000[a]
Qatar	280 000	140 000	70 000	-	-	595 000[b]	991 000[b]	-	-	800 000[b]
Saudi Arabia	1 606 000	640 000	171 000	454 000[e]	295 000[a]	528 000[a]	500 000[b]	1 320 000	-	800 000[a]
Syria	-	-	-	-	-	300 000	346 000	-	-	1 000 000[a]
Trinidad and Tobago	-	-	-	-	-	1 280 000[b]	70 000[a]	435 000	180 000[a]	840 000[b]
UAE	-	-	-	-	-	330 000[a]	-	-	135 000	800 000[a]
Venezuela	150 000	50 000	60 000	54 000	-	792 000[b]	661 000	-	-	5 120 000[b]
Total	5 914 000	1 705 000	642 000	1 443 000	978 000	16 992 000	14 790 000	4 627 000	1 417 000	27 565 000

[a] UNIDO estimate of proposed new unit
[b] UNIDO estimate of proposed expansion
[c] Includes some naphtha-fed, older units
[d] As VCM, some of which may be exported
[e] As EDC
[f] For 40,000 t/a SBR unit
[g] GOIC estimate

Demand for gas in excess of supply will mean that some projects, especially those for LNG, will have to draw on non-associated sources. This will not necessarily mean the end of flaring, however. In many countries, e.g. Indonesia, Malaysia, Nigeria and Syria, considerable investment would be needed to permit sole use of associated gas in preference to non-associated supplies. In this context attention is drawn to the results of a Instituto Mexicano de Petroleos' study on economic usage of small quantity of gas flared at isolated wells.[28]

Attention is also drawn to the near universal use of the ethane component in associated gas streams for its fuel rather than chemical value. At best, e.g. in Saudi Arabia, only half the available ethane will be consumed by plants either planned or under construction. The remainder is extracted in LNG and LPG facilities or consumed as fuel and feedstock along with methane.

In some developing countries[29] existing uses of associated gas as a whole, e.g. fuel for power generation and fertilizer use, are given priority over possible uses of components such as ethane and propane. In particular, associated gas is considered suitable for petrochemical production only where other possible requirements have been met. This, however, is in contrast to the experience of major oil companies. They find that where ethane and propane are available in sufficient quantity, they can command sufficient premium value over other hydrocarbons to justify their separation even where any resulting shortfall in gas volume has to be made up with fuel oil for power generation.

Impact on world markets

By 1985, gas-based production in the 18 developing countries could account for around ten per cent of world ethylene and low-density polyethylene, and around 19 per cent of world methanol and ammonia (see table 12). With the possible exception of methanol, for which future uses are not yet clear, all the increases forecast could therefore be easily absorbed in world markets, even if there were no plans for domestic consumption. The volume entering international trade in practice will be considerably smaller.

---

[28] See also R. W. Rui, "Production of low-density polyethylene from ethane and propane in associated gas produced in the N. W. of Peru", UNIDO internal document, March 1980.

[29] R. W. King, op. cit p.6

Table 12

Global impact of gas-based industrial capacity in oil producing developing countries (mid 1980s)

Product	OPDC Capacity t/a	World Capacity[a] t/a	OPDC Share %
Ethylene	5 914 000	65 000 000	9.2
LDPE	1 705 000	15 554 000	10.9
HDPE	642 000	10 120 000	6.3
PVC	1 454,000	16 000 000	2.5
Ammonia	16 992 000	88 900 000	19.1
Urea	14 790 000	...	...
Methanol	4 627 000	25 250 000	18.3
Aluminium	1 417 000	28 000 000[b]	5.0
Sponge iron	19 470 000	960 000 000[c]	2.8

Source: table 11, annex II

[a] See Part Two

[b] A. Bokor, A. B. Domory, I. Varga, The Economic Use of Aluminium, UNIDO/108, 335, p. 7.

[c] The World Iron and Steel Industry, UNIDO/ICIS. 89, Nov. 1978

The impact of plans to use flared gas in other ways—general gasification of the economy, power generation, industrial heating operations such as cement manufacture and oil refining etc.—is harder to assess. If it were possible to recover 50 per cent of the 1978 volume for general energy use, the yield would be an additional 70 billion cu m, around three per cent of anticipated world gas supply.

Chapter III

Selected products based on associated gas

Determining the optimum utilization of gas at a particular location requires detailed studies to evaluate such factors as gas consumption, the value of the products to the local economy, their export earnings potential and the problems they might pose in international distribution and marketing. Competing projects for using associated gas can be compared using either their return on capital investment or the netback value of the gas at the plant inlet valve after deducting all downstream costs from the realized price at the point of sale.[30] For this study, however, a representative group of products was pre-selected to test the economic feasibility of using associated gas using non-economic criteria.

Criteria for selecting products

In practice, what is optimum at one location could be far from the best solution for another. Taking into account the plants actually being built (table 10), the criteria for selecting products for further study were therefore drawn up as follows:

- Products should be either petrochemical- or energy-intensive in manufacture, thereby placing gas-based production at maximum advantage;
- Intermediates and finished products should be capable of being traded internationally as well as becoming the basis of local transformation industries and local supplies;
- Processing should make use of individual components of associated gas, e.g. ethane for ethylene products, methane for ammonia and methanol;
- Products should be as far downstream as possible before being considered for export;

---

[30] See for example G. Bonfiglioli, F. Cima, Economics of Gas Utilization in Different Fields, paper to OAPEC Symposium on the Utilization of Natural Gas, June 1981.

- In the case of petrochemicals, products should not immediately rely on local sources of aromatics as co-feedstocks. Aromatics-based products could be introduced later as they become available from refining operations;
- Where possible, all products should be related so that all of one family, e.g. olefin derivatives, can be produced at a single location;
- Technology should be generally available but proven in world-scale plants.

Products selected - and rejected

The list of products finally selected for detailed competitivity studies is shown divided into four product areas:

Table 13

Products selected for further study

Petrochemicals

- Ethylene
  - Ethylene oxide
    - Ethylene glycol
  - HDPE
  - LDPE
  - Methanol

Fertilizers

- Ammonia
  - Urea

Metals

- Sponge iron
  - Steel
- Aluminium

Energy Sources

- LNG
- LPG
- Methanol

The world supply and demand position through the 1980s is estimated in Part Two, and the prospects for their competitive production in developing countries is discussed in Part Three of this report.

In the case of petrochemicals, the list reflects a secretariat judgement on which products will be generally competitive if based on associated gas in developing countries. Many others might be equally good or better options in particular cases. Two that were not pursued for this final report--PVC and PP--deserve particular comment.

PVC, ethylene dichloride (EDC) and VCM would be strong candidates for inclusion in an olefins complex. Local consumption as film and sheet for packaging and agriculture and as pipe may justify the investment even where international competitivity cannot be guaranteed. In world markets, PVC is second to polyethylene with 25 per cent of bulk thermoplastics applications. Growth is expected to average around 6 per cent annually through the 1980s reaching 16.5 million t/a in 1984 and 23.1 million t/a in 1990. Of the intermediates, EDC is easily shipped for PVC production at other locations — the intention in Saudi Arabia's plan to produce 450,000 t/a in one of its projects.

The problem in producing EDC or PVC in some developing countries is the local price of chlorine. Chlorine accounts for two thirds by weight of the monomer (VCM) and—depending on plant size and uses for co-product caustic soda from a chlor-alkali plant—its price can vary between zero and over $500/ton. A new 92,000 t/a unit in the Middle East, sized to supply a medium-sized VCM plant and selling caustic soda at $185/ton would yield chlorine at $460/ton.[31] A 640,000 t/a unit in Mexico obtaining only $120 for its caustic soda would produce chlorine at $275/ton. In this context existing VCM producers in industrialized countries may have an overwhelming advantage: in 1980 they were able to buy chlorine at $160 to $200/ton.

Another candidate product not considered further in this study is polypropylene. As noted in chapter II, the most favourable feedstock for ethylene available in associated gas is ethane. Ethane, however, produces negligible quantities of by-product propylene, the monomer for polypropylene. If propylene is required, ethane-propane feedstock could be obtained by changing the operating conditions on an LPG unit to leave more propane in the ethane stream. The problem is that, as a cracker feedstock, ethane-propane may mean higher cost ethylene; depending on the value of by-product credit:

31/ Assuming 85 per cent load factor and including 25 per cent ROI.

Ethylene production cost (1980), $/ton[a]

Feedstocks	Mexico	Arabian Gulf
Ethane	211	187
Ethane-propane	239	256

Source: UNIDO estimates

a/ Conditions as per methodology in chapter X.
b/ Propylene valued at: Mexico, $300/ton; Arabian Gulf, $400/ton.

The above example shows how a decision to make polypropylene from associated gas feedstocks could increase ethylene costs by 13 to 36 per cent.[32] In practice the increase (if any) depends (a) on the relative cost of ethane and ethane-propane, and (b) on the local value of by-product propylene. Raising propylene prices to $400/ton in Mexico, for example, would cut ethylene prices by $12/ton in the ethane-propane route.

On this basis, developing countries seeking polypropylene production should look to oil refinery sources of propylene or, as in Libya, via naphtha cracking.

---

[32] Heavier feedstocks such as butane and pentane give still better propylene yields. The opportunity cost of these components as LPG exports is much higher, however: $ 300/ton compared to $ 25/ton assumed for ethane and $ 90/ton for ethane-propane.

PART TWO

WORLD SUPPLY AND DEMAND FOR SELECTED PRODUCTS

In Part One, eleven industrial products were selected for further investigation as examples of gas-based industrial production in developing countries. Part Two looks at their world supply and demand position during the 1980s and beyond. The discussion focuses on present market size, the assumption and forecasts for the rest of the decade, the gap between supply and demand, and the structure and pricing trends in major industrial markets. Each chapter concludes with an assessment of opportunities for new producers.

Methodology note

The diversity of industrial sectors in Part Two poses problems concerning both of regional classification and the time period covered. Ideally, forecasts for each sector would cover the same time period, use the same base year and be broken down into the same regions and subregions. But while such a presentation would give international and interregional comparability, in practice each industrial sector prefers its own typology and forecast time periods. Such an approach better reflects the problems and characteristics of the individual sectors.

The decision for this study was a two-tier approach. Firstly the data for supply and demand are presented for each sector using its own typology. Secondly uniform supply and demand balances are developed for all the sectors in terms of two macro-economic regions: developed and developing countries. This permits sectoral comparability with previous and ongoing work in the sector, while addressing the main aim: an estimation of potential future markets for gas-based industries.

Chapter IV

Petrochemicals[33]

Forecasts for petrochemical end-products employ a combination of methods. Future developed country demand is based on delphi forecasts made for the OECD countries.[34] According to these estimates, annual growth rates for all thermoplastics are 6 per cent up to 1984 and 4 per cent thereafter up to 1990. To this is added planned demand in eastern Europe, estimates for which have been cross-checked with announced capacity increases (assuming 80 per cent stream factor) and associated buy-back obligations. Developing country demand is built up from announced and committed plant capacities.

Present market size

World demand for ethylene in 1979 reached 37.2 million tons (table 14). Over 93 per cent was produced and consumed in industrialized countries. Over 80 per cent was accounted for by three thermoplastics: PVC (33 per cent), LDPE (33 per cent) and HDPE (15 per cent). The thermoplastics consumption pattern is slightly different between developed and developing regions because of HDPE's lower penetration levels in developing countries. In industrialized countries a further 12 to 17 per cent of ethylene is consumed as ethylene oxide/ethylene glycols; in developing countries this use reaches only two per cent.

These differences partly reflect the developing countries' present production capability. The balance is best in PVC where developing countries account for 13 per cent of production and nearly 18 per cent of world demand. In the polyethylenes supply and demand are equally unbalanced: 9 per cent of production versus 18 per cent of demand for LDPE and four per cent of production versus 12 per cent of demand for HDPE. As intermediates, ethylene oxide and glycol are mainly captive inputs to other petrochemical units and their supply and demand are well balanced in all regions. In developed countries, producers convert most of their oxide to glycols - 50 per cent to monoethylene glycol, 10 per cent to higher glycols. Other outlets for the oxide include surfactants (13 per cent), glycol ethers (seven per cent), ethanolamines (six per cent). Monoethylene glycol goes 40 per cent for anti-freeze and 40 per cent for polyester fibre.

---

[33] Excluding methanol for which see chapter VI.

[34] "Forecast of the Plastics Industry" - Report of the IKU-Delphi Pannel, Aachen, Federal Republic of Germany, 1979, given in Modern Plastics International, March 1981, pp. 30-33.

Table 14

Capacity, production and demand for olefins and derivatives (1979)

Product		Developed Countries 1000 t/a	Developing Countries 1000 t/a	World Total 1000 t/a	Share of Developing Countries %
Ethylene	Production	34 962	2 355	37 317	6.3
	Demand	34 850	2 350	37 200	6.3
LDPE	Production	11 094	1 040	12 134	8.6
	Demand	9 941	2 195	12 136	18.1
HDPE	Production	5 504	229	5 733	4.0
	Demand	4 867	677	5 564	12.2
PVC	Production	10 793	1 618	12 411	13.0
	Demand	10 171	2 216	12 387	17.9
Ethylene Oxide	Production[a]	6 685	410	7 095	5.8
	Demand	5 509	331	5 840	5.7
Ethylene Glycol	Production[a]	5 785	515	6 300	8.2
	Demand	4 310	527	4 837	10.9

[a] Nominal capacity.

Source: Annex III

In developing countries the pattern is radically different: 98 per cent of the oxide goes to monoethylene glycol, one per cent to higher glycols. Better profitability from non-glycol derivatives is now a limiting factor on the quantity of oxide available for conversion to glycols, however.

Supply and demand during the 1980s

The main factors influencing world demand for individual peterochemicals in the 1980s are overall economic growth, the sectoral demand for plastics, fibres and organic chemicals, and a degree of substitution among competing products such as PVC, LDPE, HDPE, polypropylene in the plastics group, and between various man-made fibres.

The demand for ethylene is expected to grow 5.1 per cent annually through to 1984 (table 15) and slightly faster, 5.5 per cent annually thereafter as consumption in developed countries picks up.[35] Although in 1984 the developing countries as a group will be short of ethylene, by 1990 there will be a clear surplus, most of it due to plants in the Middle East with, as yet, insufficient down-stream consuming capacity. With both demand and supply growing at three times the rate in industrialized countries, the developing countries will account for a growing portion of world output - reaching nearly 17 per cent by 1990. All developing countries' growth rates will fall slightly from their high pre-1984 levels except Africa and centrally planned Asia. Africa[36] will gain its first ethylene cracker - in Nigeria in 1985/86. China has delayed its petrochemical expansion in Peking until 1986/87.

The outlook for LDPE reflects developed country expectations concerning inroads by HDPE and PP. For this reason Japan expects zero growth through to 1984. Demand will pick up thereafter with linear low-density PE regaining some of LDPE's lost markets. Developing country demand will grow at double the world rate, and as a group the developing countries will still be importing around 1.3 million t/a in 1984. Consumption amounts to 23 per cent of world demand in 1984 and will reach nearly 30 per cent in 1990.

HDPE follows a similar pattern to LDPE. Growth rates are higher in all regions, but developed countries' demand will be mainly supported by Eastern Europe where large units are due on stream in the Soviet Union and Romania.

---

[35] These are conservative forecasts compared to some. Predicasts (July 1980) predicts ethylene to grow at 6.4 per cent annually through to 1995.

[36] Excluding north African countries grouped in the Middle East.

Demand balance and growth ra

Product	
Ethylene -	Developed Countries
	Developing Countries
	World Total
	% Developing Countries
LDPE -	Developed Countries
	Developing Countries
	World Total
	% Developing Countries
HDPE -	Developed Countries
	Developing Countries
	World Total
	% Developing Countries
PVC -	Developed Countries
	Developing Countries
	World Total
	% Developing Countries
Ethylene - oxide	Developed Countries
	Developing Countries
	World Total
	% Developing Countries
Ethylene - glycol	Developed Countries
	Developing Countries
	World Total
	% Developing Countries

Source: Annex III

a/ 1979 to 1984
b/ Production less demand
c/ 1984 to 1990

Table 15

tes for selected petrochemicals (1984 and 1990)

1984			1990	
Demand 1000 t/a	Growth Rate % [a]	Balance 1000 t/a [b]	Demand 1000 t/a	Growth Rate % [c]
42 920	4.2	140	54 880	4.3
4 850	15.6	-130	10 990	14.6
47 765	5.1	10	65 870	5.5
10.1	-	-	16.7	-
11 920	3.7	1 409	15 360	4.3
3 630	10.6	-1 305	6 525	10.3
15 550	5.1	104	21 885	5.9
23.3	-	-	29.8	-
6 340	5.4	585	8 185	4.3
1 265	13.3	-480	2 340	10.8
7 605	6.5	105	10 525	5.6
16.6	-	-	22.2	-
12 840	4.8	340	16 550	4.3
3 710	10.8	-1 110	6 530	9.9
16 550	6.0	770	23 080	5.7
22.4			28.3	-
6 795	4.3	1 415	...	...
507	8.9	385	...	...
7 302	4.6	1 773	...	...
6.9	-	-	-	-
5 180	3.7	1 425	...	...
527	9.2	-8	...	...
5 998	4.4	1 417	...	...
13.6	-	-	-	-

Developing country average annual growth rate of 13 per cent to 1984 reflects a major jump in centrally planned Asia, where plants in Peking come on stream in 1986/87. Africa's first unit, also in Nigeria, will be in operation in 1986; demand for its output will be built up in advance by imports.

Although PVC will be in world surplus in 1984, the developing country imbalance will top 1.1 million tons. Growth patterns are similar to LDPE. In 1984 developing countries are to account for 22 per cent of world consumption; in 1990 it will be 28 per cent.

The outlook for ethylene oxides/glycol turns mainly on the future for anti-freeze in the northern developed countries, and polyester fibre worldwide. Of the two, polyester fibre will provide nearly all the growth; developing countries' dependence on this particular fibre is nearly total. In line with this, the developing countries will balance their supply and demand for ethylene glycol by 1984. At the same time, there could be a world surplus of 1.4 million t/a.

Market structure 37/

The petrochemical sector in industrialized country markets shows a marked trend towards downstream integration. Pressed by external competition, olefin producers consistently aim to raise the volume of captive business they can control. Merchant olefins sellers have seen their business reduced accordingly. The main exception to this trend are the ethylene pipeline grids in northwest Europe and the U.S. Gulf coast. In other areas there is a strong trend to integrate forward from ethylene into all the products selected for this study.

In Europe all LDPE/HDPE and ethylene oxides/ethylene glycol is now captive to ethylene producers. Some 13 out of 22 EDC/VCM producers are back integrated into ethylene. The main opportunities for new ethylene and intermediate suppliers are therefore the handful of non-integraged companies (Hoechst, ISR, Polysar, Unifos and Monsanto) and a merchant market that lives off the imbalances within the main companies.

In the United States there is also a high degree of integration but the sheer size of the market enables a large number of non-integrated firms to stay in business. Reflecting this there is a large merchant market in all major petrochemical products.

The Japanese petrochemical industry in contrast is much more fragmented. Only three out of the 12 olefins producers are integrated downstream into more than two products.

37/ For a more detailed discussion of market structure and price trends, see the "Second worldwide study of the petrochemical industry", UNIDO, 1981.

The companies involved in merchant sales are generally oil companies that have moved into ethylene and its immediate derivatives. In addition there are a number of traders, but their involvement in most of the petrochemicals considered for this study is minimal. Only in the case of ammonia (see chapter V), ethylene glycol and methanol (chapter VI) are they a significant factor.

The third agency in the petrochemical market is the distributor - a service oriented company that fulfils two purposes: 1) selling to small consumers, 2) selling on behalf of companies that do not have their own sales force. Distributors rarely handle base petrochemicals, but they are very active in polymer sales, especially LDPE, HDPE, and PVC.

Opportunities for new producers

Between 1984 and 1990 the following plants will be needed to meet estimated demand at the end of this decade:

Product	Plant capacity t/a	No. units
Ethylene	500,000	18
LDPE	200,000	32
HDPE	75,000	39
PVC	250,000	26

On the basis of developing country demand some 45 per cent of these units could be in developing country regions. Given their favourable feedstock positions developing countries with access to associated gas could justify investment in many more to supply developed country demand.

As evident from the balance analysis (table 15), in the medium term developed country markets as a group are either self-sufficient in the products selected or there is a large surplus aimed at export markets. The main exception is Japan, which has already made a number of arrangements to import from plants outside, many set up as joint ventures. Developing country strategy should therefore focus on co-operation arrangements that will preempt further investment in these areas.

Faced with high feedstock costs, the Japanese market may prove the easiest for newcomers to enter. Given the tariff protection and the existence of highly organized marketing/trading corporations working under supervision of MITI, co-operation with Japanese companies is probably essential. A plus factor would be these companies access to other sout-east Asian markets.

The North American market is the most developed petrochemical market worldwide, but it is highly structured and has substantial, although lessening low cost feedstock base. The market has traditionally been protected by high tariffs, but in co-operation with existing suppliers, access for intermediates could be assured and tariffs re-negotiated at government level.

Because of its integration, western Europe is the most difficult of the three major markets. In addition there is still a basic unwillingness to abandon domestic investment plans in favour of say North African or Arab Gulf investments. Western Europe furthermore is protected by tariffs and quotas that the EEC would be reluctant to abandon where imports were perceived to threaten domestic industry. As with North America, access to Western Europe would have to proceed by way of co-operation with existing suppliers, supported by inter-government negotiations on tariffs and quoters. Given sufficient determination, however, the example of Eastern Europe's penetration of West European markets shows what may be achieved.

The alternative to penetrating in industrialized country markets is to compete with industrialized country producers in the growing developing country markets. Although still small, these are the most dynamic and in many cases would involve developing countries' suppliers in lower freight costs than their exports to developed countries.

Chapter V

Fertilizers

All gas-based production of fertilizers involves ammonia. The prospects for developing countries using associated gas to penetrate these markets are therefore determined by the supply and demand for ammonia and its nitrogen fertilizer derivatives.

Present market size

World consumption of nitrogen fertilizers reached 57.1 million tons of nitrogen in 1979/80 according to latest figures from FAO.[38] Some 40 per cent was consumed in developing, 60 per cent in developed countries. Growth in over-all demand during the 1970s averaged 6.1 per cent annually, but it was both unevenly distributed and subject to considerable fluctuation. The 1978/79 growth of 6.5 per cent meant a recovery of demand compared to previous years, but it was confined to the developed countries, mainly the United States. Developing country demand in contrast showed a marked drop from the 12 per cent annual growth throughout most of the 1970s to around 6 per cent in 1978/79. Both markets recovered in the 1979/80 season.

On the supply side production rose 6.7 per cent in 1978/79 to reach 59.6 million tons, 57.3 million of which was available for agriculture. This increase was less than the 8.9 per cent reported for the year before but it exceeded the 1970-77 average.

During 1978/79, the largest quantitative increases came from Western Europe and centrally planned Asia. The West European performance reflected better plant capacity utilization enhanced by idling or shutdown of capacity in the United States and Japan. An absolute decline in nitrogenous capacity in Japan was due to a rationalization programme for ammonia and urea induced by the rapidly rising cost of feedstocks.

---

[38] The two most authoritative sources of information in this sector are FAO for past and actual figures (table 16) and the UNIDO/FAO World Bank Working Group on Fertilizers for yearly medium-term forecasts five and 10 years ahead. FAO is currently casting backwards its historical data base on China. The Working Group's five-year supply and demand forecast represents the harmonized result of commercial, lending and technical assistance authorities. The data and trends are crosschecked with the information supplied by individual members in a Delphi panel of experts. From 1978 onwards, the Group undertook a 10-year demand forecast using trend analysis judgements to reach panel consensus (see table 17).

For a relatively recent analysis of medium- and long-term demand forecasts based on the Group's records since 1976, see "Supplement to the Second World-Wide Study on the Fertilizer Industry 1975-2000", UNIDO, July 1980.

During 1979/80, there was a substantial drop in production growth in most regions: Africa and Eastern Europe suffered absolute declines of 16.5 per cent and 1.2 per cent respectively. The USSR suffered setbacks due to bad weather, shortcomings in feedstocks and other temporary technical and logistical difficulties. Feedstock and power problems beset India, Turkey and the Philippines. Plant operation problems are still hindering the USSR, India and Mexico. The Republic of Korea is reducing production due to domestic and export market constraints brought on by the feedstock price squeeze.

Table 16 shows that the developed countries have a nitrogenous fertilizer supply capacity well in excess of their demand, whereas the developing countries remain in a deficit situation. Comparison of total nitrogen production with ammonia capacity for 1979[39] shows that the developing countries operate at 67.3 per cent of ammonia capacity versus 79.5 per cent for the developed countries.

However, in many countries there is an unusually large proportion of new ammonia capacity not matched by a corresponding downstream conversion capacity to nitrogenous products: it is capacity that was primarily intended to supply ammonia export markets. This points to potential medium-term difficulties that may have to be resolved through improved operating rates for new downstream plants, additional conversion capacity and price increases in finished fertilizers that would bring idling plants in the developed countries back on stream.

Supply and demand in the 1980s

Table 17 shows planned increases in ammonia capacity, the supply of nitrogenous products up to 1984 and the demand for nitrogenous products up to 1990. From this it is clear that in quantitative terms the developing countries are far outstripping the developed countries in adding new ammonia capacity. In the period 1979-84, the developing countries will roughly double the new capacity increases in the developed countries. The only significant developed country increases are in the Soviet Union, where the full impact of 41 plants recently built but not yet in full operation will be evident.

---

[39] After deducting China's 4.3 million tons of nitrogen carbonate, fertilizer by-products from technical nitrogenous production and 7 per cent conversion losses from ammonia to nitrogenous products.

Table 16

Capacity, supply and demand for ammonia and nitrogenous fertilizers (1979)

Region	Ammonia capacity *million tons N*	Production nitrogenous products		Demand nitrogenous products	
		Fertilizers *million tons N*	% technical	Fertilizers million tons N	% technical
North America	18.9	12.9	28.0	11.1	27.6
Western Europe	15.7	11.7	26.0	10.0	26.8
Eastern Europe	30.4	15.1	11.6	12.0	14.6
Other developed countries	4.0	2.2	52.4	1.5	113.1
Total developed countries	69.0	41.8		34.6	
Africa	0.7	0.1	6.7	0.5	8.4
Latin America	4.0	1.5	4.1	2.7	4.6
Near East	4.2	1.5	1.6	1.8	2.6
Far East	7.9	4.6	2.9	6.3	2.9
Centrally planned Asia	5.7[a]	9.6	5.2	11.2	4.5
Total developing countries	22.5	17.8		22.5	
World total	91.5	59.6		57.1	
Share developing countries, per cent	24.5	29.8		39.4	

Source: FAO

[a] Excludes ammonium bicarbonate capacity

Table 17

Forecast capacity, supply and demand for ammonia and nitrogenous fertilizers (1984 and 1990)

Region	Ammonia capacity 1984 million tons N	Fertilizer production 1984 million tons N	Fertilizer demand 1984 million tons N	Surplus/ deficit (-) 1984 million tons N	Fertilizer demand 1990 million tons N
North America	19.22	13.85	13.18	.72	15.00
Western Europe	16.86	12.57	10.87	1.70	12.30
Eastern Europe	35.91	18.02	14.88	3.14	18.00
Other developed countries	4.12	2.32	1.66	.66	1.87
Total developed countries	76.11	46.76	40.59	6.17	47.17
Africa	1.31	0.68	0.79	-.11	1.05
Latin America	6.58	2.79	3.81	-1.02	4.84
Near East	6.24	3.07	2.65	.42	3.60
Far East	11.89	7.20	8.62	-1.42	11.25
Centrally planned Asia	8.37	12.43	14.04	-1.61	17.00
Total developing countries	34.39	26.17	29.91	-3.74	37.74
World total	110.50	72.93	70.50	2.43	84.91
Share developing countries, per cent	31.1	35.9	42.4		44.4

Comparing firmly committed projects between 1976 and 1984 with actual ammonia plant implementation, it is evident that although developing countries planned to double ammonia capacity during the past four years, they could only achieve 65 per cent of their aims; the lag on target dates was around two years. The medium-term projects to 1984/85 show that the developing countries plan an even larger ammonia capacity increase than in the previous period - despite current learning curve problems in the Far East and Latin America.

On the demand side consumption of nitrogenous products in developing countries is growing twice as fast as that in developed countries through till 1990. This reflects their low per capita consumption. Nevertheless, the trend shows a steady decline in growth rate through the decade. This situation may be exacerbated when the thorny problem of fertilizer subsidies and increased food production in developing countries is settled in the relatively near future.

Market structure and prices

In the developing countries, which will account for the largest share of future sales, the nitrogenous industry is predominantly government-owned with minor participation of local private industry, co-operatives and joint ventures with the large chemical/oil corporations. Eastern Europe apart, these same chemical/oil corporations dominate fertilizer production in developed countries - again with some minor participation by Western European Governments and some agricultural co-operatives.

The final market in all countries is composed of a large number of small consumers. Export deals are generally made, however, with either a relatively small number of importers in each country or with government organizations. Such contracts necessarily involve large quantities. The United States market is somewhat exceptional in having an established pipeline and ammonia distribution business: both are experienced in importing and redistributing ammonia in large quantities. Such deals have to be made on a long-term basis and would not, for example, be accessible via trading organizations. Traders on the other hand could help build up spot sales to the United States market.

The bulk of all transactions is traded at contract prices. These prices are generally not published but the trends in spot prices generally reflect similar trends in the contract market.

Despite large price fluctuations from January 1976 to January 1981, extrapolating the longer-term trend in spot prices gives a urea price of $307/ton in 1984 and $213/ton for ammonia c.i.f. Western Europe. The prices in early January 1981 were $235 and $175 respectively. The United States Gulf Coast f.o.b. prices are about 20 per cent lower than c.i.f. Western Europe ones.

Since traditional producers are suffering increases in production and distribution costs and are no longer able to absorb them through increases in efficiency, contract prices may undergo steeper growth rates than spot prices unless new producers with substantial production cost advantages make their presence felt in international markets.

Opportunities for new producers

The difference between 1984 capacity and forecast demand in 1990 indicates a requirement for a net additional 12 million tons N of capacity in this period. This is equivalent to 44 1000 ton/day units—many of which could be advantageously built to use developing countries' associated gas.

World exports of nitrogenous fertilizers reached 11.99 million tons of nitrogen in 1979/80, up 1.3 per cent over the previous year (table V C). The ratio of international trade in nitrogen to world consumption increased from 18.8 per cent in 1974/75 to 22.0 per cent in 1978/79. A fall to 21.0 per cent in 1979/80 reflected a deterioration of regional supply. With the exception of the Near East, all of the developing regions stagnated due to production difficulties, thus reversing the past trend of increased regional self-sufficiency. The situation was such that even a high-cost fertilizer producer such as Japan could export more fertilizer than it consumed domestically; similarly, Western Europe, a high-cost producing region, became the leading exporter. It should be noted that practically all imports by the developed countries represent intra-trade in that macro-region.

The gap analysis for ammonia identifies North America and Western Europe as areas with both short- and long-term deficits of ammonia. In Western Europe developing country strategy should focus on pre-empting local investment. The main competition for both these markets will come from the USSR.

The main opportunity for developing country producers remains, however, other developing countries.

Table 18

World trade in nitrogenous fertilizers by region

Region	Exports		Imports	
	1978/79 million tons N	1979/80 million tons N	1978/79 million tons N	1979/80 million tons N
North America	3.20	3.32	2.08	2.48
Western Europe	4.13	4.01	2.62	2.75
Eastern Europe	2.30	2.32	0.35	0.27
Other developed	0.90	0.83	0.09	0.12
Total developed countries	10.53	10.48	5.14	5.62
Africa	-	-	0.36	0.40
Latin America	0.16	0.21	1.34	1.37
Near East	0.69	0.88	0.95	1.03
Far East	0.41	0.42	2.47	2.47
Centrally planned Asia	-	-	1.53	1.56
Total developing countries	1.26	1.51	6.65	6.65
World total	11.84	11.99	11.79	12.41
Share of developing countries in world total (%)	10.6	12.6	56.4	54.7

Source: FAO, March 1981

These have continued to increase their imports of nitrogenous fertilizers over the years—mainly from the developed countries. As yet they do not appear to have reached a cost benefit ceiling on fertilizer prices in relation to prices for their exported agricultural commodities. Their main constraints are foreign exchange restrictions and temporary shortages in domestic fertilizer production.

Chapter VI

Methanol[40]

Methanol is probably the least predictable of the 11 products selected: although over-all world chemical uses will continue to grow at around 6 per cent annually through to 1983, forecasting fuel uses is hindered by the present small size of that sector of the market.

Present market size

In 1979, world methanol capacity totalled 13.5 million t/a, of which North America accounted for 31 per cent, Western Europe 27 per cent, Eastern Europe 22 per cent and the rest of the world together 20 per cent (table 19). Supply and demand followed a similar pattern so that with the exception of Africa, regional imbalances were five per cent of production or less. Africa's 330,000 t/a surplus production, mainly accounted for by Libyan output, broadly equals the world surplus. The North American data suggest there may be significant intra-regional trade, however: the United States deficit of 157,000 t/a could have been more than covered by Canada's 228,000 t/a surplus.

The demand analysis (table 20) shows chemical uses of methanol accounting for 55 to 75 per cent of consumption; formaldehyde production alone consumes 42 per cent in the United States and 59 per cent in Europe and Japan.

Supply and demand in the 1980s

If methanol has a future of interest to developing country producers during the present decade, it will be determined by development of its fuel uses.[41] MTBE (methyl tertiary butyl ether) and TBA (tertiary butyl alcohol) mixtures are already produced, and direct gasoline blending is already practiced in Europe. All are on a limited scale at present. In addition, synthetic gasoline, methanol as a complete automobile fuel and its use in power generation are at the stage of technical and economic evaluation.[42] Two views - one conservative, one optimistic - show where this could lead: SRI estimates the total demand for fuel use in the United States will reach

---

[40] Condensed from independent studies by COIC

[41] New chemical uses are also envisaged for the 1990s;

[42] See annex IV for further details.

Table 19

Methanol capacity supply and demand
1978/1979

Region/country	Capacity 1000 t/a	Production 1000 t/a	Demand 1000 t/a	Surplus/ Deficit (-) 1000 t/a
United States	3 600	2 923	3 074	-151
Canada	446	400	172	228
Mexico	182	103	88	15
Total North America	4 228	3 426	3 334	92
Argentina	36			
Brazil	4 148			
Total South America	134	143	143	-
Austria	30			
France	400			
FRG	1 285			
Italy	320			
Holland	660			
Norway	60			
Portugal	-			
Spain	200			
United Kingdom	660			
Total Western Europe	3 665	2 750	2 810	-60
Bulgaria	30			
Czechoslovakia	160			
GDR	250			
Poland	220			
Romania	250			
USSR	1 650			
Yugoslavia	360			
Total Eastern Europe	2 920	2 350	2 300	50
Republic of China	100			
India	85			
Indonesia	-			
Japan	1 254			
Republic of Korea	375			
Malaysia	-			
New Zealand	-			
China - Taiwan	126			
Total Asia	1 940	1 390	1 460	-70
Algeria	100			
Egypt	10			
Libyan Arab Jamahiriya	330			
South Africa	27			
Zambia	2			
Total Africa	469	330	50	330
Bahrain	-			
Saudi Arabia	-			
Other	60			
Total Middle East	60	50	55	-5
Total	13 466	10 494	10 157	337

Source: GOIC

a/ 1979 data

b/ Based on 1978 supply and demand

Table 20

Methanol demand analysis for industrialized country markets (1978)

Use	United States per cent	Western Europe per cent	Japan per cent
Formaldehyde	42.5	59.0	59.0
DMT	4.4	6.0	4.0
Methyl halides	8.8	...[b]	3.0
Methyl amines	5.2	...[b]	3.0
Methyl methacrylate	6.6	...[b]	5.0[c]
Acetic acid	6.7	1.0	-
Solvents	9.0	9.0	6.0
Single cell protein	-	-	-
Gasoline blending	2.4	-	-
MTBE	-	2.0	-
Power generation	-		
Miscellaneous	16.4[a]	23.0	20.0[d]
Total demand, t/a	2 074	2 910	1 070

Source: GOIC (based on SRI and Chem Systems estimates)

a/ Includes glycol methyl ethers, formaldehyde inhibitors and antifreeze
b/ Included under miscellaneous
c/ All other methylated chemicals
d/ Includes 4% for pharmaceuticals and agrochemicals

550,000 t/a in 1983 and 2.4 million t/a in 1990 (1.1 million tons for gas blending, 758,000 t/a for MTBE and 500,000 t/a for power generation;[43] Snam Progetti envisages a 30 to 40 per cent penetration of the West European market giving a methanol demand exceeding 25 million t/a in 1990.[44]

Among the chemical uses, formaldehyde will continue to be the main consumer. In turn urea and phenolic resins are the main outlets for formaldehyde and their demand depends on the fortunes of the housing sector. In industrialized countries, demand in the period 1978 to 1983 is expected to grow at 3 to 4 per cent annually.

The greatest growth potential in chemicals lies in acetic acid, for which methanol is increasingly selected as the feedstock. In the United States this use is growing at 15 to 16 per cent annually, in Western Europe and Japan at 38 per cent annually. Despite these high growth rates, acetic acid will account for only 4 per cent of demand in Europe, 7 per cent in Japan and 10 per cent in the United States.

Other chemical uses for methanol will grow at 6 to 7 per cent annually in all markets. In addition, production of single cell protein based on methanol is planned in Western Europe.[45] If this gains acceptance the resulting outlet for methanol could be significant. One optimistic source sees world-wide methanol demand reaching 2.5 to 5 million t/a in the late 1980s.

The impact of these considerations on the regional supply and demand position in 1983 and 1990 are shown in table 21. This shows a 6 per cent world surplus in 1983 and a 1 per cent deficit in 1990. As at present North America will be in surplus in 1983 with excess capacity in Canada making up the United States' deficit. By that year South America will become a net importer to the tune of one-fifth of its demand, and Western Europe will be importing 430,000 t/a - nearly 12 per cent of demand. These should easily be covered by surpluses arising in Eastern Europe, Asia, Africa and the Middle East. The forecast for 1990 is necessarily speculative. A large amount of new capacity is either planned or under construction but it is uncertain if the demand will exist when they start up. In contrast to projects like the

---

[43] SRI International, Zurich.

[44] Snam, Italy.

[45] For details see annex VI.

Sabic/Japanese plant in Saudi Arabia, the majority of new producers are banking on a major growth in fuel uses. The Chem Systems scenario for 1990 shown in table 21 assumes world demand and supply roughly in balance, with demand broadly double that in 1978. Europe's deficit will have risen to 30 per cent of demand, and North America as a whole, together with Asia, is also in deficit. They would be relying heavily on suppliers from Africa and the Middle East to make up the difference. Altogether seven 2500 t/d units would be required: two in Latin America, two in the Asian developing countries, and three in the Middle East/Africa.

New outlets for chemical methanol

In addition to the fuel and petroprotein uses emerging towards the middle and end of this decade, the 1980s may see further growth in chemical consumption. In principle methanol can be used as the feedstock for the following downstream chemicals:

Petrochemicals derived from methanol

Conventional technology	New techology
Formaldehyde	Vinyl acetate
DMT	Ethanol
Methyl methacrylate	Acetaldehyde
Methyl amine	Ethylene glycol
Chloromethane	Ethylene [a]
Acetic acid	Methyl acetate
	Acetic anhydride [a]

Source: Toyo Engineering.

---

[a] For further details, see annex IV.

Market structure, prices and trade

As in other petrochemicals, methanol production in the United States and Western Europe has been dominated by large chemical companies producing it for their downstream operations:

- In Western Europe 40 to 50 per cent of methanol demand for formaldehyde is captively produced;
- In the United States around 56 per cent of all uses is captive and in the case of individual markets, e.g. formaldehyde, acetic acid, methylamines, it is 100 per cent.

Table 21

Supply and demand for methanol 1983 and 1990

Region/country	1983			1990[a]		
	Production[b] 1000 t/a	Demand 1000 t/a	Surplus/ deficit (-) 1000 t/a	Production[b] 1000 t/a	Demand 1000 t/a	Surplus/ deficit (-) 1000 t/a
United States	4 550	4 760	-210	5 340	8 070	-2 730
Canada	655	215	440	1 500	312	1 188
Mexico	160	150	10	...	...	...
Total North America	5 365	5 125	240	6 840	8 382	-1 542
South America	212	272	-60	1 641	578	1 063
Western Europe	3 250		-430	4 025	5 960	-1 939
Eastern Europe	3 000	2 800	200	5 620	5 000	620
Japan	...	...	...	950	2 120	-1 170
Australia, New Zealand	...	...	...	360	125	235
Other	...	...	...	1 130	1 087	43
Total Asia	2 170	2 030	140	2 440	3 332	-892
Africa	380	70	310	2 575	100	2 475
Middle East	580	80	500			
Total	14 957	14 057	900	23 141	23 352	-211

Source: GOIC

a/ Chem Systems
b/ Assuming load factors: developing countries, 80%; industrialized countries, 85%.

Captive marketing thus has an established history in the industrialized country markets and it is relevant to note that a large part of the output from the planned Sabic/Japanese plant in Saudi Arabia will also be for captive use.

Nevertheless there is still a large merchant market open to competitive producers, assuming relatively free trade continues. In addition, as the Sabic/Japanese example shows, it is possible, by means of long-term co-operation arrangements, to pre-empt some of the investment needed for captive outlets.

In this context, prospective developing country producers should note the large price differences (table 22) that existed between the industrialized country markets in the 1970s. The advantageous position of low feedstock prices in the United States is clear, and this will continue to be a determining factor. The relative energy prices in the United States are expected to rise with decontrol of natural gas prices. New producers would therefore have good chances of penetrating all the major industrialized country markets.

A substantial and growing international trade is therefore likely. By the late 1980s this will be measured in millions of tons annually. From the supply and demand position shown in table VI C, the flows will be from areas of low cost energy - the Middle East, North Africa, Canada, Indonesia, Australia. The buyers will be the United States, Western Europe and Japan.

In the development of this trade, the ease of transportation will be a particularly important factor.

Market opportunities for new producers

The foregoing suggests three possible market strategies for new methanol producers:

- Entering existing and growing methanol merchant markets;
- Establishing captive use arrangements with user chemical companies;
- Establishing captive use arrangements with oil and other companies involved in methanol fuel applications.

Bearing in mind that sales to the fuels applications market is the area of greatest potential, all three possibilities must be pursued in practice. A detailed analysis will be required to show which, if any,

Table 22

Methanol prices in industrialized country markets

Year	United States $/ton	Western Europe $/ton	Japan $/ton
1973	46.6	80 - 85	...
1974	86.5	350	183
1975	119.7	135	195
1976	133.0	100 - 135	212
1977	139.7	130 - 146	214
1978	146.3	130 - 146	271
1979	162.9	182 - 198/	309
1980	...	222 - 265/	

Source: SRI International, Zurich

a/ 2nd quarter
b/ 1st quarter
c/ February

downstream alternatives - e.g. MTBE or synthetic gasoline - should be made by methanol producers rather than in the major consuming regions of the world.

Another factor of key importance to the development of the world methanol industry is relative energy costs. There are already serious plans for producing coal-based methanol. The extent and speed of development of coal-based methanol should be based on its over-all economics: no doubt political factors will also play a role.

New producers will have to judge this balance of advantage of alternative feedstocks and plant locations to determine their target market share.

The one thing that appears certain is that methanol demand will grow, and that in the next decade new demand for fuel uses is likely to be far greater than that for chemical applications. For intending new producers perhaps the most difficult question is when new capacity will be required: in all probability the fuels demand will not really grow rapidly until the capacity is available and product is offered for sale at competitive prices. The timing of plant investment becomes a matter of judgement involving a shrewd assessment of future potential fuels market growth.

Chapter VII

Sponge iron

Direct reduction of iron ore to make sponge iron—which in turn becomes the raw material for electric furnace steel—is gaining ground in both developed and developing countries.[46] With capital costs only 60 per cent of those for traditional blast furnace-basic oxygen furnace (BF-BOF) converter combinations, the approach is regarded as particularly suitable for developing countries moving into steel production for the first time. Direct reduction plants are also claimed easier to operate because they involve no liquid metal handling, and because they avoid the infrastructure, environmental and operating problems associated with blast furnaces.

Present market size

Although sponge iron is itself a marketable product, all developing country use to date has been as raw material for local steel production. In any market, however, sponge iron has to compete with the traditional raw material for electric furnace steel making - steel scrap.

The size of the scrap market in selected countries is indicated in table 23. This shows the developed countries with a combined total of 229 million tons annually. The main scrap suppliers are the United States, the Federal Republic of Germany and France; the main importers (excluding intra-EEC trade) are Spain, Japan and Eastern Europe. In comparison both the international trade in scrap (41 million tons between these countries) and the 1979 world sponge iron production capacity (14.1 million t/a) were small.

Supply and demand during the 1980s

Looking ahead, both production and trade in scrap will grow at a rate permitted by the health of the steel industry as a whole. In industrialized countries 70 to 75 per cent of scrap is either recirculating (internal to the steel plant) or processed scrap (prime quality direct from steel users). A depressed steel sector therefore means reduced availability of scrap for electric steel making.

---

[46] For a more detailed description including the different processes available for making sponge iron, see "Progress Report: Industrial utilization of associated gas", UNIDO, May 1980, p. 121.

Table 23

Iron and steel scrap: consumption,
trade and apparent supply in selected countries
1979

REGION	Consumption million t/a	Imports million t/a	Exports million t/a	Domestic Supply million t/a
EEC	69.1	10.1	9.6	68.6
Japan	45.6	3.4	-	42.2
United States	70.0	1.0	10.0	79.4
Canada	8.3	1.1	1.0	8.3
Other OECD[a]	15.4	4.2	-	11.2
Brasil	5.7	-	-	5.7
USSR	56.3	-	-	56.3
Other Eastern Europe	23.7	0.9	-	22.8

Source: IISI data

[a] Austria, Spain, Sweden, Yugoslavia

Table 24

Price trends in steel scrap[a]
($/ton, 1979 dollars)

	Actual		Forecast	
	1978	1979	1980	1984
United Kingdom	62.54	121.00	115.00	150.00
France	64.51	125.74	125.00	150.00
Federal Republic of Germany	66.33	113.80	115.00	150.00
Japan	76.79	106.34	101.63	150.00
United States	72.25	112.38	115.00	150.00

Source: World Steel Dynamics 1979

[a] Domestic prices

The outlook for sponge iron as an export product is determined by three factors: the growth in electric furnace steel making per se, the supply and demand for steel and steel scrap, and certain technical problems in shipping sponge iron in large quantities.

In practice whatever the fortunes of the steel industry as a whole, the market for sponge iron and scrap steel should expand rapidly. The reason: electric furnace steel making is rapidly gaining ground on all other processes. By the year 2000 it is forecast to account for over 40 per cent of world output.[47/]

Vis-à-vis scrap, the future for sponge iron depends on the price and availability of ferrous scrap. While the expansion of electric furnace steel is increasing demand for both scrap and sponge iron, the growing practice of continuous casting[48/] and general improvements in rolling yields is decreasing the amount of home scrap, thereby further increasing demand for purchased scrap. At the same time, scrap quality is going down, partly due to increased use of coated and alloy sheets, but also because a combination of rising labour costs and low copper prices have made selection and classification of ferrous scrap less attractive. This is leading to further shortages in number one heavy melting scrap needed for electric furnace steel making.

At the same time there is growing interest in sponge iron as one of the raw materials for blast furnace operations. Favourably located direct reduction plants may therefore find markets even in areas where steel making in general is plagued by over-capacity and where protectionist measures are introduced to keep finished steel imports to a minimum.

Market prospects for sponge iron will also be determined by redeployment trends in the world iron and steel industry. The number of traditional steel makers with excess iron ore and access to cheap fuel dwindles with every rise in gas prices. It seems likely therefore that by 1985 a large portion of world sponge iron output will come from merchant plants constructed where energy and/or iron ore are cheap. Ore will still be sold to steel makers for blast furnace reduction with coking coal. But for electric steel, the ore will be

---

[47/] G.P. Mathur, Technological Profiles in the Iron and Steel Industry, UNIDO/IOD.191, 1978, p. 117.

[48/] G.P. Mathur, op. cit., p. 141.

shipped increasingly to producers with low-cost gas and coastal sites suitable for deep water ports and direct reduction plants. One such plant is already under construction at Emden in the German Federal Republic. A similar unit to serve the European market but run as a joint venture by the Arab countries is suggested here as a subject for further study.

Market structure and prices

One structural trend of importance to sponge iron producers is the growing number of non-integrated steel works - i.e., rolling mills without steel or iron-making capacity. In developing countries, some of these mills will want to integrate backwards to eliminate ingot and billet imports and to reuse their own recirculating and processed steel rather than going all the way to blast furnace or direct reduction plants, some will prefer to import the raw materials - scrap or sponge iron. Which raw material any given electric furnace uses depends on relative price. Sponge iron producers can generally command some premium over No. 1 steel scrap, but the prices of both sponge iron and steel scrap (see table 24) generally move together in response to demand for steel generally. In periods of rising demand, increased scrap usage provides industrialized country steel makers with a relatively easy route to higher production rates and scrap prices therefore tend to rise. As production moves into high gear, the supply of scrap increases, tending to stabilize its price. In periods of slack steel demand the reverse is true. As a rough guide scrap prices tend to be about one-third of the export price of a common product, e.g. rebars. Fluctuations, however, may range between 20 and 40 per cent.

In practice, the February 1981 price of United States export scrap (No. 1 heavy melting) was approximately $98 per ton f.o.b. United States East Coast. In Antwerp, export rebar prices were quoted at $302 in January but fell to $280 in February and $265 in March 1981.

Prices are often much higher in the developing countries. At a time when scrap sold for $65 per ton in Europe, Argentina and Brazil installed direct reduction plants to avoid paying $180 to $200/ton for imported scrap.

Opportunities for new producers

Somewhat in contrast to the long-term optimism for sponge iron, the outlook for finished steel exports is not encouraging. Export sales to industrialized countries will remain difficult and, because of tariffs and low prices, they are likely to remain uneconomically unattractive for some time. New steel producers in developing countries are therefore advised to build capacity to supply domestic or regional needs. Once local steel supplies are available, domestic consumption and the capital goods sector generally grow rapidly.

The present depression in world steel production has been accompanied by major doubts on the validity of medium- and long-term forecasts. Citing the disappearance of an adequate base and the non-availability of statistical or other tools suited to the new situation, the International Iron and Steel Institute in Brussels has presently withdrawn all its forecasts.

There is nevertheless general agreement that world demand in 1985 will be between 960 million and 1 billion t/a, and that present over-capacity in the industrialized countries is around 80 million t/a, i.e. 16 per cent of their effective capacity.[49/] Over-capacity is most severe in the EEC, and although less critical in the United States, protectionist forces in that market are stronger.

The demand trend in the developing countries is much more encouraging. Despite rapid increases in production capacity in the past ten years - bringing capacity up to 13 per cent of the world total - the Third World imported 35 million tons of steel in 1977 compared to 15 million tons in 1967.[50/] These countries are likely to remain substantial net importers.

Given current reservations on long-term steel forecasting, the following estimates of world demand are presented only as a general indication of a conservative demand growth assuming the industry emerges from its present crisis within the next two years:

Year	World demand (billion t/a)
1985	0.960
1990	1.200
1995	1.430
2000	1.665

Source: The World Iron and Steel Industry (Second Study), UNIDO/ISIS.89, November 1978.

49/ The OECD Observer, March 1980, p. 3.

50/ The OECD Observer, op. cit., p. 10.

When considering such long-term demand one further factor must be taken into account. In contrast to their position on petrochemicals, most oil-producing developing countries will have to import iron ore or pellets. If they then try to export sponge iron or finished steel they could be subject to pressure from both ends. Their value added might thus be determined by outsiders.

Chapter VIII

Aluminium[51]

For the medium term, i.e. through to 1985, there are widely differing views on world demand patterns for aluminium. These reflect different assumptions concerning the nature, depth, timing and eventual rate of recovery from the recession affecting the large industrialized economies— the United States, Western Europe and Japan—which are the principal consumers of aluminium.

The longer-term forecasts through to 1990 and beyond show better agreement.

Present market size

Local world aluminium consumption in 1979 amounted to 20.1 million tons, the result of an average annual growth of 5.4 per cent through the 1970s (see table 25). Some three-quarters was accounted for by primary aluminium, the remainder by output from secondary aluminium smelters, i.e. scrap reprocessers. Nearly 90 per cent of both total and primary aluminium consumption was by the developed countries. Of these, six—the United States, Japan, the Federal Republic of Germany, France, Italy and the United Kingdom— took 58 per cent of world demand. The two largest developing country consumers were China with 580,000 t/a and Brazil with 280,000 t/a.

On the supply side (table 26) 14.8 million tons of primary aluminium were produced - again nearly 90 per cent in developed countries. This left a world deficit of 810,000 tons to be taken from stocks, nearly all accounted for by the developing countries' deficit of 750,000 tons. The biggest developing country producers were again Brazil and China, but consumption in both exceeded local supply.

Production growth through the 1970s amounted to only 1.4 per cent annually, most of it accounted for by developed country producers.

Supply and demand in the 1980s

Factors determining developments in the aluminium industry during the 1980s can be summarized as follows:

---

[51] Condensed from independent studies by GOIC, see "The Industrial Uses of Associated Gas: Primary Aluminium," GOIC, November 1980.

Table 25

Aluminium consumption (1979) and growth
rates in the 1970s

Country	Total aluminium		Primary aluminium	
	Consumptions[a] 1000 t/a	Growth[b]	Consumptions[a] 1000 t/a	Growth[b] %
United States	6 577	4.5	4 999	4.1
Japan	2 230	7.3	1 744	7.5
FRG	1 436	5.6	1 021	4.8
France	711	4.2	552	3.3
Italy	678	5.5	410	4.4
United Kingdom	575	0.5	404	0.0
Other OECD	2 113	5.0	1 905	5.3
Total OECD	14 320	4.8	11 035	4.6
Eastern Europe	3 720	5.6	2 838	4.8
Total developed countries	18 040	4.9	13 873	4.6
Brazil	280	13.4	252	13.0
Arab countries	178	31.0	142	30.4
Iran Turkey	110	18.4	102	18.6
China	580	11.1	450	10.7
Other developing countries	951	8.6	846	7.2
Total developing countries	2 069	10.4	1 792	10.1
TOTAL WORLD	20 109	5.4	15 655	5.1

Source: GOIC

[a] Primary production plus primary imports less primary exports, plus or minus inventory

[b] Average annual growth 1970-79

Table 26

Primary aluminium demand, supply, surplus and deficits in 1979

Country	Demand 1000 t/a	Supply 1000 t/a	Supply growth 1000 t/a	Surplus/ deficit (-) 1000 t/a
United States	4 999	4 557	0 5	-442
Japan	1 744	1 010	-2 0	-734
FRG	1 021	742	1 5	-279
France	552	395	0 1	-157
Italy	410	209	4 9	-141
United Kingdom	404	359	4.1	-045
Other OECD	1 905	2 992	-0 5	1.087
Total OECD	11 035	10 324	0.2	-711
Eastern Europe	2 838	2 800b/	1 7	-038
Total developed countries	13 873	13 124	0 5	-749
Brazil	252	230b/	15 1	-022
Arab countries	142	233b/	14 6	091
Iran Turkey	102	40b/	-04 7	-062
China	450	275b/	11 4	-175
Other developing countries	846	953b/	9 8	107
Total developing countries	1 792	1 731	8 4	-061
TOTAL WORLD	15 665	14 855	1 4	-810

Source: GOIC

a/ Average annual growth 1974 to 1979

b/ GOIC estimates

- The persistent growth shown over the past 15 years will continue with little loss through substitution by other materials. The industry's innovative capacity will continue to yield new products that stimulate over-all growth rate;
- In line with the above, a total world aluminium consumption will increase at an annual rate of 4.3 per cent in the period 1979 to 1995;
- Due to increasing secondary aluminium (scrap reprocessing) activity, primary aluminium consumption will grow slightly less rapidly, namely at 4 per cent annually;
- Scrap reprocessing level in industrialized countries is assumed to continue at 25 per cent of total consumption. In the newly industrialized countries, e.g. Brazil, the corresponding figure would be 10 per cent and in other developing countries 4 per cent;
- The economic projections for individual countries are controlled by an assumed real increase in oil prices of not more than 4 per cent;
- With the exception of Japan, the six major aluminium consuming countries will experience compound growth rates of less than 3 per cent for their GNPs. Japan is assumed to grow at 4.6 per cent.

With these assumptions, world consumption is forecast to reach 25.7 million tons in 1985, 32.8 million tons in 1990, and 39.6 million tons in 1995 (see table 27). Average annual growth rates for the period are 4.6 per cent (for 1979 to 1990) falling to 4.0 per cent (1979 to 1995). As in the past, consumption growth rates in the developing countries will strongly outpace those in the industrialized countries (table 28). Developing countries' share of consumption will increase only marginally however:

Forecast total aluminium consumption growth rates and breakdown

	Consumption growth rate		Breakdown of consumption			
	1990/1979 %	1995/1979 %	1979 %	1985 %	1990 %	1995 %
Developed countries	4.6	4.1	88.5	87.7	86.1	83.5
Developing countries	8.2	7.9	11.5	12.3	13.9	16.5
World total	4.6	4.3	100.0	100.0	100.0	100.0

Source: table VIII D.

Table 27

Forecast aluminium consumption

	1980		1985		1990		1995	
	Total 1000 t/a	Primary 1000 t/a	Total 1000 t/a	Primary 1000 t/a	Total 1000 t/a	Primary 1000 t/a	Total 1000 t/a	Primary 1000 t/a
United States	5 942	4 498	8 029	5 941	9 541	6 965	10 558	7 655
Japan	2 363	1 843	2 997	2 248	4 228	3 086	5 373	3 869
FRG	1 480	1 051	1 804	1 272	2 206	1 544	2 633	1 835
France	733	567	884	672	1 066	800	1 232	912
Italy	696	421	849	509	1 023	611	1 191	709
United Kingdom	576	404	705	491	806	559	910	628
Other OECD	2 150	1 927	2 657	2 323	3 379	2 911	4 108	3 490
Total OECD	13 940	10 711	17 925	13 456	22 249	16 479	26 005	19 098
Eastern Europe	3 830	2 907	4 630	3 412	6 040	4 385	7 140	5 141
Total developed countries	17 770	13 618	22 555	16 868	28 289	20 861	33 145	24 239
Brazil	295	266	401	353	589	501	807	670
Arab countries	178	171	351	334	591	547	952	859
Iran	94	86	188	166	296	242	474	365
Turkey								
China	620	479	900	681	1 350	1 013	1 940	1 445
Other developing countries	1 007	897	1 323	1 148	1 743	1 474	2 353	1 963
Total developing countries	2 194	1 899	3 163	2 682	4 569	3 777	6 526	5 302
Total world	19 964	15 517	25 718	19 550	32 858	24 638	39 671	29 541

Source: GOIC

Table 28

Forecast growth rates for aluminium average annual consumption

	1990/1979		1955/1990		1995/1979	
	Total %	Primary %	Total %	Primary %	Total %	Primary %
United States	3.4	3.1	2.0	1.9	3.0	2.7
Japan	6.0	5.3	4.9	4.6	5.6	5.1
FRG	4.0	3.6	3.6	3.5	3.9	3.7
France	3.8	3.4	2.9	2.7	3.5	3.2
Italy	3.8	3.7	3.1	3.0	3.6	3.5
United Kingdom	3.1	3.0	2.5	2.4	2.9	2.8
Other OECD	4.8	4.3	4.0	3.7	4.5	4.1
Total OECD	4.1	3.7	3.2	3.0	3.8	3.5
Eastern Europe	4.5	4.0	3.4	3.2	4.1	3.8
Total developed countries	4.6	4.2	3.2	3.0	4.1	3.8
Brazil	7.0	6.4	6.5	6.0	6.8	6.3
Arab countries	13.4	13.0	10.0	9.4	12.3	11.9
Iran Turkey	9.4	8.0	9.9	8.6	9.6	8.3
China	8.0	7.7	7.5	7.4	7.9	7.6
Other developing countries	5.7	5.2	6.1	5.9	5.8	5.4
Total developing countries	8.2	7.7	7.4	7.0	7.9	7.5
TOTAL WORLD	4.6	4.2	3.8	3.7	4.3	4.0

Source: GOIC

The medium-term supply capability for primary aluminium based on known plans through to 1985 (table 29) follows a similar pattern to demand. World production is forecast to reach 20.2 million tons representing an average growth rate of 5.3 per cent in the first half of the 1980s. This would give a small over-all surplus of nearly 700,000 tons. As with the demand side, developing country growth rates are approximately double those of the developed countries, but their over-all contribution improves only marginally:

Forecast primary aluminium production growth rates and breakdown

	Production growth rate 1985/1979 %	Breakdown of production 1979 %	1985 %
Developed countries	4.3	88.3	83.4
Developing countries	11.6	11.7	16.6
World total	5.3	100.0	100.0

Source: table 29.

Although the developing country growth rates (table 29) are high, they start from a small base. This stands in contrast to the expected performance of the non-major OECD producing countries. As a group their production already exceeds that of Japan, the world number two producer, and their expected growth rate is over 9 per cent. Australia in particular will be making a large contribution by 1985—reaching 1.51 million t/a, compared to 425,000 tons in 1979. The expected exports will total 1.25 million tons.

Market structure and prices

One of the key factors allowing a greater role for new aluminium producers in future is the changing structure of the world aluminium industry.

Having long dominated world production, consumption and distribution, the influence of six transnational aluminium producers[51] is declining. Nevertheless with 56 per cent of the world's alumina output — the smelters' main raw material — and 41 per cent of primary aluminium production still under their control, the influence of these transnationals cannot be ignored for a long time to come. One option taken up by many new producers[52] is to

---

[51] Alcan, Canada; Alcoa, United States; Kaiser Aluminium, United States; Reynolds Metals, United States; Pechiney-Ugine, France; Alusuisse, Switzerland.

[52] For example, Venalum in Venezuela, Dubai in the United Arab Emirates and Albras in Brazil.

Table 29

Forecast primary aluminium production

Country/region	1980			1985			
	Demand 1000 t/a	Supply 1000 t/a	Surplus/deficit (-) 1000 t/a	Demand 1000 t/a	Supply 1000 t/a	Growth[a/] %	Surplus/deficit (-) 1000 t/a
United States	4 498	4 557	59	5 941	5 125	2.0	-816
Japan	1 843	1 080	-763	2 248	1 100	1.4	-1 108
FRG	1 051	727	-324	1 272	746	0.1	526
France	567	407	-160	672	648	8.6	-24
Italy	421	283	-138	509	311	2.4	-198
United Kingdom	404	376	-28	491	390	1.4	-101
Other OECD	1 927	3 513	1 586	2 323	5 040	9.1	2 717
Total OECD	10 711	10 943	232	13 456	13 360	4.8	-96
Eastern Europe	2 907	2 866	-41	3 412	3 511	3.8	99
Total developed countries	13 618	13 809	191	16 868	16 871	4.3	3
Brazil	266	263	-3	353	423	10.7	70
Arab countries	171	314	143	334	484	13.0	150
Iran Turkey	86	22	-64	166	82	12.7	-84
China	479	300	-179	681	800	19.5	119
Other developing countries	897	993	96	1 148	1 557	8.5	409
Total developing countries	1 899	1 892	-7	2 682	3 346	11.6	664
Total world	15 517	15 701	184	19 550	20 217	5.3	667

Source: GOIC

a/ 1979 to 1985

sign long-term supply contracts either with the big six or with international trading houses that import into deficit markets such as Japan. Although major producers of primary aluminium themselves, the transnationals are in constant need of dependable additional supplies.

As a partial alternative, the London Metal Exchange (LME) has emerged as a major commodity trading centre for primary aluminium ingot. While the existence of this market favours the independent producer, there may be limits to its benefits. If the quantities traded through the LME become too large, it would lead to unstable aluminium product pricing downstream - with adverse effects on their market development.

Another limitation on using the LME as a main outlet for aluminium ingot from independent producers is the fluctuation and possible low level of LME prices. In 1980 the free market price ranged between $1,500 and $2,200/ton. In November 1980 the price of $1,530 was 12 per cent down on the previous year. The likelihood of obtaining better prices under long-term contracts to stable export markets is illustrated by the forecast price movements through to mid 1982:

Short term price forecast for primary aluminium ingot

	Year (by quarter)						
	1980	1981				1982	
	4th qr. cents/ lb.	1st qr. cents/ lb.	2nd qr. cents/ lb.	3rd qr. cents/ lb.	4th qr. cents/ lb.	1st qr. cents/ lb.	2nd qr. cents/ lb.
London Metal Exchange	74.36	73.55	73.78	72.17	75.47	82.07	86.35
% change on previous year	- 11.16	- 21.05	- 9.14	- 7.30	1.49	11.58	17.03
Alcan Export Price	79.91	79.85	80.47	81.54	82.21	83.54	86.34
% change on previous year	15.03	9.45	1.38	2.72	2.87	4.62	7.28
US Producer List Price	75.91	75.85	76.97	78.04	78.71	81.04	84.34
% change on previous year	15.42	14.92	6.91	8.39	3.68	6.85	9.56

A combination of primary metal marketing at three-month contract prices to domestic fabricators, long-term contract supplies to export markets on a formula pricing basis and a smaller proportion of aluminium ingot being marketed through metal brokers would provide the best conditions for consistent economic development.

The opportunistic marketing of primary aluminium ingot in the last two years has probably been over-exaggerated if the over-all situation in commodity trading — which has shown very similar fluctuations in market prices for a wide range of commodities—is considered. Highly speculative marketing pricing policies are therefore not to be substantially encouraged for a major new entrant to this industry.

On the raw materials side, the International Bauxite Association (IBA) is establishing guideline prices for bauxite and alumina export. The IBA is currently attempting to link the price of metallurgical grade alumina to ingot prices, for example.[53] In addition national policies regarding mining of bauxite and its on-site refining into alumina are designed to create greater added value and increase national benefits through greater foreign currency earnings. This promotes autonomous structures within the industry and strengthens other commercial agreements at the expense of more traditional multinational structures. It would appear that these changes are not resisted by the big six transnationals, however, as they have advantages to them as well as to the supplying countries.

Opportunities for new producers

As the medium-term trend makes clear, the traditional large consumers of primary aluminium are becoming less self sufficient. The reason is partly the changing energy base, which by itself has meant a dramatic review of the location parameters for primary smelters.

The gap analysis shows that no new primary smelting capacity is required world wide beyond the present investment programme until 1985. Beyond that commitments have not been made, but with a lead time of four and a half years for installation and commissioning, decisions on primary metals investment for the period 1985 to 1995 will be taken in the near future.

---

[53] In November 1979 the IBA Council of Ministers recommended a minimum c.i.f. price for metallurgical grade alumina in 1980 in the range of 14 to 16 per cent of the average American metal market list price for 99.6 per cent purity primary aluminium ingot.

The total world aluminium investment requirements beyond current commitments are as follows:

Investment requirement to 1995
(million t/a)

	1980	1985	1990	1995
Existing and planned smelting capacity	17.5	21.8	21.8	21.8
Production at 92% load factor	16.1	20.1	20.1	20.1
Demand for primary metal [a/]	15.5	19.5	24.6	29.5
Metal deficit (minus)/surplus	0.6	0.6	- 4.5	- 9.4
New capacity requirements at 92% load factor	-	-	4.9	10.2

---

a/ From table VIII.

This conservative view of the aluminium industry's future indicates a global requirement of 60 to 70 150,000 t/a smelters to meet demand through to 1995. If the over-all economic outlook were to improve to the extent of 5 per cent annual growth rate, demand for primary metal would be increased by an additional 3.2 million tons in 1995. This would mean a further 20 smelters. Given the intensive nature of aluminium production, it would seem logical that many of these smelters be built in countries where energy is inexpensive. In that sense, the use of associated gas that would otherwise be flared would put developing countries in an advantageous position: how advantageous is shown in chapters X and XI.

Low cost energy for smelter power is of course only one factor. Alumina may have to be imported. On the other hand some developing countries, e.g. the Arabian Gulf region, have alumina clays that would not normally be considered for alumina refining. It may be feasible to apply more energy-intensive refining to such clay feedstocks, thereby avoiding the cost of shipping in ready refined alumina.

The biggest incentive to set up gas-based alumina production may prove, however, to be the changing energy picture elsewhere. In the past large industrial power consumers such as the aluminium industry have been able to negotiate very favourable tariff rates. It is no longer accepted that this should be at the expense of domestic and commercial power users and industry faces a rising tariff burden on top of a general rise in energy charges.

Pricing policies for alternative energy forms - gas, hydropower, lignite, etc. - in national and State planning are apparently moving through a confused period. The utility value of these alternative energy sources is, in many cases, calculated at the heat equivalent value of oil. Whatever view is taken of the rationality of this practice, its main consequence for the application of flared gas is that the trend strongly favours the establishment of a primary aluminium industry which will have a growing economic advantage as time passes.

As with sponge iron, plans for gas-based aluminium smelters in developing countries should be tempered with the consideration that both the raw material—bauxite and alumini—and large parts of the market for the product are in the hands of others. To avoid consequent external control of the value added, some form of co-operation with raw material and downstream distributors may be advisable (see chapter XII).

CHAPTER IX

Energy sources - LNG, LPG, and pipeline gas

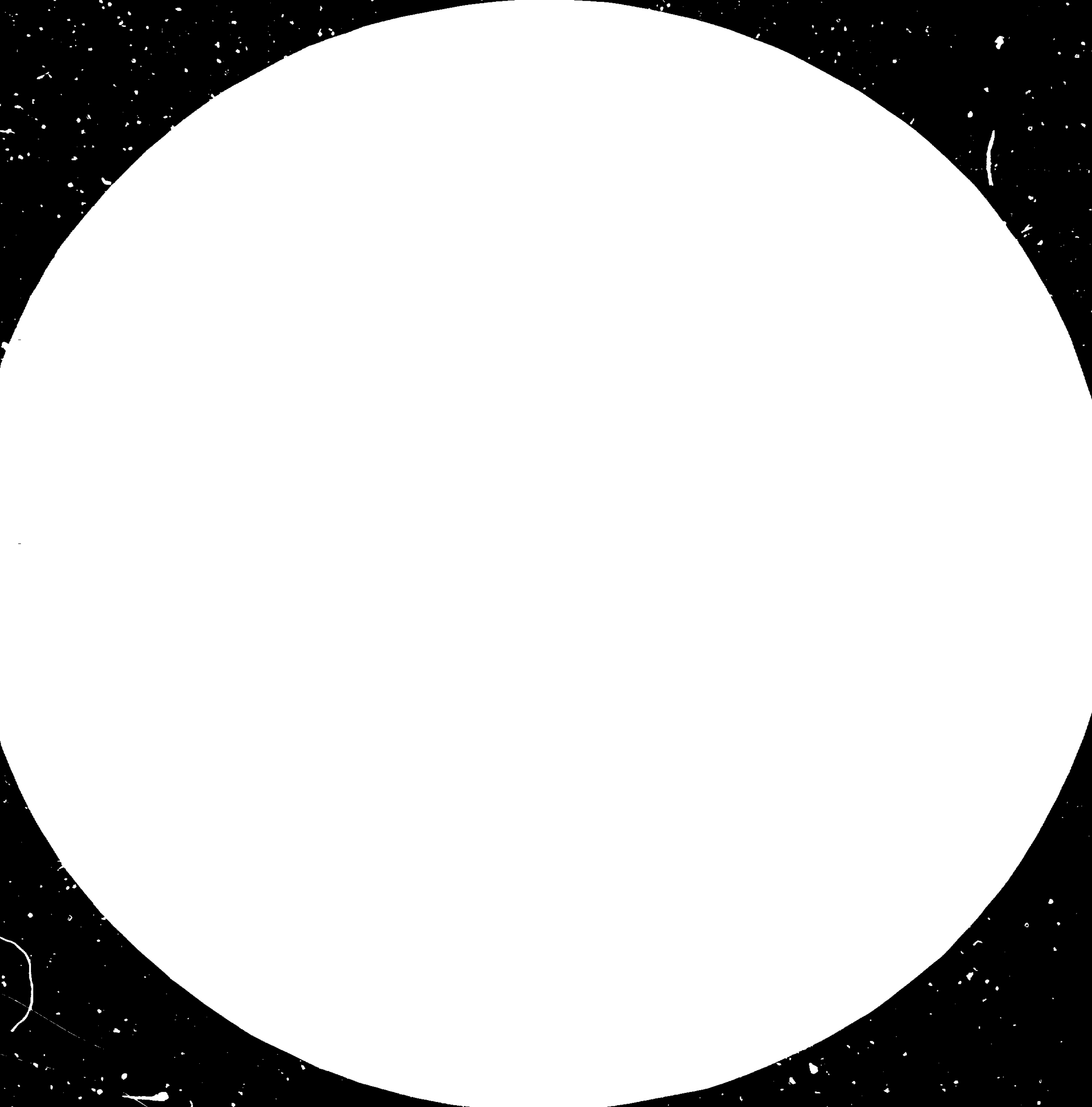
Energy exports can be considered either as an alternative to industrial utilization of associated gas (the case with LNG) or complementary to it (LPG). When LPG is exported, propane/butane components are extracted from the gas, leaving an ethane-methane residual gas for petrochemical, fertilizer and other uses. When LNG is exported, all the associated gas is liquefied, precluding any local industrial use.

Whether either represents an optimum use for associated gas depends on the cycle of world market prices. At present both LNG and LPG prices are high, but the higher energy prices have yet to work their way through to higher prices for the industrial alternatives. Thus, LNG economics are more attractive now than at any time in the past. Furthermore, if OPEC producers succeed in linking gas export prices to oil price levels, the natural price swing back in favour of industrial products will be slow—possibly resisted altogether. If they fail, the relative price of LNG will drop to where it was in the mid- to late 1970s when non-energy uses of associated gas gave significantly better returns.

LNG

Present market size

The world trade in LNG and pipeline gas in 1980 totalled 230 billion cu m. All but 2 per cent was imported by industrialized countries. Nearly three-quarters were supplied as pipeline gas and two-thirds came from the industrialized countries themselves (table 30). The five main suppliers were the Netherlands, the Soviet Union, Canada, Norway and the OPEC countries.



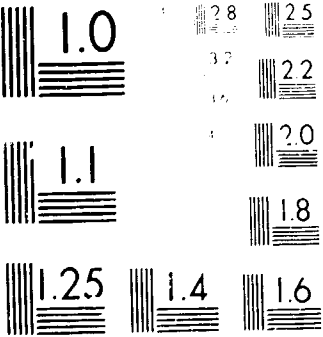

1.0
2.8
2.5
2.2
2.0
1.1
1.8
1.25
1.4
1.6

Table 30

Supply and consumption of LNG and pipeline gas (1980)

Exporter	LNG billion cu m/a	Pipeline gas billion cu m/a	Importer	LNG billion cu m/a	Pipeline gas billion cu m/a
Alaska	1.38	-	United States	12.98	14.56
Canada	-	14.56	Western Europe	13.24	113.73
Netherlands	-	50.95	Japan	26.94	-
North Sea	-	15.59			
Norway	-	23.38			
Total OECD countries	1.38	104.48	Total OECD countries	53.16	128.29
USSR	-	44.05	Eastern Europe	20.24	12.87
Total developed countries	1.38	148.53	Total developed countries	76.40	141.16
Afghanistan	-	2.96	Argentina	-	2.86
Algeria	21.17	-	Brazil	-	2.45
Bolivia	-	5.31			
Brunei	7.67	-			
Colombia	1.53	-			
Indonesia	12.78	-			
Iran	9.91	9.44			
Libyan Arab Jamahiriya	3.52	-			
UAE	5.11	-			
Total developing countries	61.69	17.71	Total developing countries	-	5.31
Total world	63.07	166.24	Total world	76.40	146.57

Source: United Nations,E/C.7/106

Supply and demand in the 1980s

The future supply of internationally traded gas, shown in table 31, is expected to reach 250 billion cu m annually in 1985 and over 370 billion in 1990. With new LNG plants probably coming on stream in Algeria, Indonesia, Malaysia, Australia, Trinidad, Colombia, Qatar and Iran, the proportion of world trade taken by LNG will rise to around 40 per cent, i.e. around 150 billion cu m/a.

The three main markets will remain Japan, Western Europe and the United States, each taking between 40 and 60 billion cu m of LNG in addition to the United States' and Western Europe's purchases of pipeline gas. The main complications in the forecast---the United States government reluctance to permit increased LNG imports and Algeria's possible switch from LNG to pipeline exports to Southern Europe---are not expected to alter total trade significantly. In other words gas will be liquefied or not, and shipped to the United States or elsewhere depending on market conditions.

Hand in hand with the expected gains for LNG is the greater role expected of gas exporters in the oil-producing developing countries. Compared to their 16 per cent of traded gas supplied in 1980, OPEC countries are expected to reach 30 per cent in 1990.

Market structure and prices

In most countries gas is distributed to end users by a large number of small utilities. Because of terminalling and distribution facilities, imports are generally handled by only a handful of agencies.

Prices are a complex issue beyond the scope of this study. Firstly they vary considerably within each major market, secondly they have been rising rapidly and there is no agreement where this should stop.

The important point for would-be gas exporters is the general acceptance of the idea that prices should be geared to the market cost of some alternative fuel and that this can be indexed to insure prices do not fall out of line

Table 31

Future supply of LNG and pipeline gas

	1985[a] billion cu m/a	1990 billion cu m/a
Alaska	1.4	4.4
Canada	14.6	17.0
Netherlands	51.0	30.0
North Sea	23.4	
Australia	5.2	14.2[b]
Total OECD countries	95.5	65.6
USSR	44.1	120.2[b]
Total developed countries	139.6	185.8
Afghanistan	3.0	2.0[b]
Algeria	42.9	79.7
Bolivia	5.3	5.0
Brunei	7.7	7.7
Chile	-	2.5[b]
Colombia	1.5	3.0[b]
Indonesia	20.5	26.0[b]
Iran	9.4	12.4[b]
Libyan Arab Jamahiriya	4.4	4.4
Nigeria	8.0	16.0[b]
Qatar	-	8.0[b]
Trinidad and Tobago	5.2	15.0[b]
UAE	5.4	5.1
Total developing countries	113.2	186.8
Total world	252.8	372.6

Source: industry estimates

a/ Mid 1980s.

b/ All or part previously designated for the United States; project and market now uncertain.

with alternative fuels over the years. Equally important, the base prices—whether they reflect thermal parity with crude oil on an f.o.b. basis as some suppliers want, or the cost of some alternative fuel in the receiving market as the buyers prefer—have risen. Investment in liquefaction plant, shipping, terminals and regasification equipment therefore looks more attractive today than three or four years ago.

Opportunities for developing countries

The largest potential market for gas is the United States, but a major policy change at government level is necessary if it is to be realized. Because of the very low reserves/production ratio some 400 billion cu m must be found or imported during the next 20 years to maintain current production levels. In practice what seems likely is a switch from gas to coal by the United States electricity utilities, thereby freeing gas for premium uses elsewhere at prices broadly equal to fuel oil. Since it would cost as much as $ 2.00/million Btu to ship LNG from the Middle East to the United States East Coast, fuel oil parity pricing at $ 4.50/million BTU rules out many would-be suppliers.

If both government policy and price levels change, there is room for up to 178 million cu m/day of additional imports by the year 2000, i.e. 7 to 8 new LNG export units.

Probably the best market for LNG in the future is Japan. The Government has deliberately chosen large-scale LNG imports as a major energy source for the rest of the century and already imports amount to 70 million cu m/day from Indonesia, Brunei and Abu Dhabi. If all boiler fuel and iron and steel energy needs are switched to gas, consumption could rise to between 280 and 340 million cu m/day by the year 2000. Through to 1990, roughly half this amount will be fully covered by additional suppliers from Malaysia, Australia, the Soviet Union and Canada. These and other countries have an opportunity of supplying a further 156 million cu m/day in the 1990s. All told, this could mean construction of 14 to 21 large-scale LNG units (25 million cu m/day) of which two thirds could be by developing countries.

In Western Europe the prospects for LNG are least clear. Demand will certainly rise steadily but the main suppliers will be the Soviet Union in the east and North African producers in the south—both via pipelines.

The USSR plans a 99 million cu m/d additional pipeline for Siberian gas. By the year 2000 there could be three transmediterranean pipelines from Algeria and Libya. In addition gas supplies from the North Sea will continue to be developed. This suggests a degree of competition that will keep LNG prices down at the levels of fuel oil.

Within the above limitations, demand in Western Europe is sufficient to justify at least three 7 million cu m/day units in the developing countries.

LPG

In 1979 world LPG consumption was around 85 million tons, equivalent to 2.65 million b/d, i.e 5% of world oil consumption. Some three quarters of this was consumed in the country where it was produced, leaving 20 million tons to be traded internationally (see table 32). Forecasts indicate that imports - mainly by the industrialized countries - could reach 34 to 47 million tons annually by the mid 1980s.[54]

In contrast to LNG, LPG is traded under short-term contracts ranging from 1 year to 5 years, and at prices reflecting short-term supply and demand positions. Despite this, interest in LPG increased towards the late 1970s and plans were laid in Japan and Europe for terminal and internal transportation systems to handle imports in large quantities.

The problems arose when prices more than doubled in 1979. Potential consumers responded by scaling down their plans for switching to LPG; others are still waiting for more stable market conditions to develop.

This explains the range of forecasts for the mid 1980s (table 32). Some 13 million tons may or may not move into international trade.

---

[54] E.K. Faridany, "The international LNG/LPG trade: 1980-1990", OAPEC Symposium on the International Utilization of Natural Gas in the Arab World, Kuwait 1980.

Table 32

LPG trade forecasts

Exports	1978/79 million t/a	1980 million t/a	1985 million t/a	1990 million t/a
Saudi Arabia[a]	4.9	6.7	17.8	12.9
Other Middle East[a]	2.5	5.7	14.2	13.6
Algeria[a]	0.2	2.0	5.6	6.1
Other Africa[a]	0.2	0.3	0.4	0.8
North Sea[b]	–	-	3.0	4.0
Western hemisphere[b]	-	-	6.0	13.0
Others[b]	-	-	2.0	-
	7.8	14.7	44.0	50.4
Imports[b]	6.5	...	9.8–16.2	22.0
Japan	9.7	...	15.0–20.0	21.7
Western Europe	4.1	...	8.9–10.8	13.2
	20.3	-	33.7-47.0	56.9

---

a/ Chem Systems estimates

b/ Ocean Phoenix Gas Transport BV, Holland

The rate of expansion of LPG trade in the 1980s will thus be determined by :

- LPG competition with other energy forms in thermal and non-thermal applications;
- LPG price in relation to these alternatives, given that supply will not become a restraint;
- The development of an orderly international trading system.

Assuming an orderly trading system evolves, the opportunities for LPG exporters will turn on price. At high prices consumption will be confined to the premium markets, i.e. household and commercial heating, agricultural uses and substitute natural gas. In all the major markets the rapid growth possibilities lie, however, in the price competitive sector: automotive and industrial uses, as a chemical feedstock, and for power generation.

PART THREE

PROSPECTS FOR COMPETITIVE PRODUCTION IN DEVELOPING COUNTRIES

The products selected for further study in Part One and shown in Part Two to have encouraging export prospects may or may not be economical to produce in a developing country. The answer in each case depends on a trade off between low feedstock and energy costs from associated gas on one side and generally higher capital charges plus shipping costs on the other.

In the following two chapters the investment and production costs are compiled for each product at four representative locations: the Arabian Gulf and Mexico as the two developing countries, and the US Gulf Coast and German Federal Republic as the two developed countries. The competitivity of each product made at the two developing country locations is determined by comparing the landed cost with the cost of making it locally in the two developed countries.

The longer-term competitive prospects are assessed with a brief look at the impact of likely technological developments in processing.

Chapter X

Investment and production costs at four representative locations

Methodology

Production costs for the 11 products selected in Part One are built up from variable and semi-fixed and fixed costs as follows:

Variable costs - feedstock, other raw materials (e.g., catalysts and chemicals), utilities, by-product credit, maintenance materials, operating supplies;

Semi-fixed and fixed costs - operating labour, maintenance labour, control laboratory, taxes and insurance, interest on working capital, depreciation.

Together these give the net cost of production at 100 per cent load factor—the basis of subsequent cost comparisons for this study. Production costs at other load factors and transfer prices including an assumed rate of return on capital[55] can be derived if desired.

The aim with these calculations has been to use a consistent set of raw material and feedstock prices for each process in order to ensure comparability in the net cost of production at each location. The methodology had to be modified to suit each product but generally followed the following pattern for petrochemicals.

Some generally accepted assumptions for calculating production costs in developed countries are shown in table 33. In contrast there are no agreed principles on how (if at all) such assumptions should be varied to reflect developing country conditions. Table 33 includes a secretariat view based on discussions with developing country planners and plant operators, but it should not be regarded as definitive. Attention is particularly drawn to three differences where lower cost and overhead requirements would offset some of the capital cost disadvantages suffered by developing countries:

- Plant overheads (cost of shared facilities such as fire services, security, common buildings, etc.) are 80 per cent of total labour instead of 100 per cent;

---

[55] In parallel work, the net cost of production at 65 and 85 per cent load factor and at transfer prices with 5 and 25 per cent ROI were developed for a range of petrochemicals, including those investigated in this study. See "The Second Worldwide Study of the Petrochemical Industry", UNIDO, June 1981, p. 00

- Taxes and insurance on fixed assets are 1 per cent instead of 2 per cent of fixed capital; and
- Interest on working capital is 5 instead of 10 per cent.

Feedstock costs, by-product values and utility costs are either those reported as market values or estimated by calculating the opportunity costs of local production.[56] All developing country figures are the best available for mid 1980; industrialized country prices are list prices for large volume, general purpose grade material, f.o.b. plant. In reality therefore there may be substantial discounting.

Plant capacity in tons/year represents annual production rate from a plant assumed to be operating 90 per cent of the time. It is appreciated that any plant handling large volumes of solid materials, e.g. sponge iron and aluminium, may have to operate at lower stream factors.

Investment costs are based on those reported by SRI and others for US Gulf Coast conditions. These are adjusted to different capacities by the ratio:

$$\frac{\text{Cost A}}{\text{Cost B}} = \left(\frac{\text{Size A}}{\text{Size B}}\right)^m$$

where m ranges between 0.6 and 0.8 depending on the process. Investment costs are divided into battery limits and offsites. Battery limits include all equipment necessary to the process including feed treatment, product separation and purification, recycle handling and packaging. Offsites include the cost of utilities generating plant, i.e. steam boilers, water treaters, cooling towers, refrigeration plant, tankage and general service facilities.

Total investment cost reflects the "overnight construction cost" at mid 1980.[57] Cost excalation during construction is not specifically foreseen, but the total investment includes a 25 per cent contingency factor.

---

[56] Notional opportunity costs are the net back value of products after deducting shipping costs from prices in a nearby international market. For this study, the UNIDO estimates were taken at 75 per cent of notional opportunity costs in order to represent situations where local industry obtains locally-produced intermediates and raw materials at advantageous prices.

[57] For similar data projected to mid 1985, see "The Second Worldwide Study of the Petrochemical Industry", op. cit., p. 00.

Table 33

Assumptions used in calculating petrochemical production costs

Cost component	Developing country	Industrialized country
Maintenance materials[a]	3% of ISBL per year	3% of ISBL per year
Maintenance labour[a]	3% of ISBL per year	3% of ISBL per year
Operating supplies	10% operating labour	10% operating labour
Control laboratory[d]	20% operating labour	20% operating labour
Plant overhead	30% total labour	100% total labour
Taxes and insurance[b][d]	1% total fixed capital	2% total fixed capital
Depreciation	10% of fixed cost	10% of fixed cost
Working capital:		
Stores	1% of fixed capital	0.5% of fixed capital
Cash	0.5% of fixed capital	0.5% of fixed capital
Raw material inventory	5 days at purchase value[c]	5 days at purchase value
Finished product inventory	30 days at direct cost plus plant overhead[d]	30 days at direct cost plus plant overhead
Accounts receivable	40 days at direct cost plus plant overhead[d]	40 days at direct cost plus plant overhead
Accounts payable	30 days raw material consumption plus 11 days labour	30 days raw material consumption plus 11 days labour
Interest on working capital	5%	10%

a/ For plants including refrigeration plant a further 1½% should be added.

b/ Excludes income taxes; covers cost of insuring fixed assets and local taxes on assets.

c/ 60 days for imported materials.

d/ Varies considerably by product and country. For discussion see "The Second Worldwide Study of the Petrochemical Industry", *op. cit.*, p. 00.

Source: SRI and UNIDO estimates

Investment costs for other locations are related to those for the US Gulf Coast by means of the following location factors:

Location	Location factor
US Gulf Coast	1.00
Federal Republic of Germany	1.15
Arabian Gulf	1.30
Mexico	1.25

Petrochemicals and fertilizers

The feedstock costs, by-product values and utility costs used for calculating production costs in the petrochemical sector are listed in table 34. Those for the United States and the Federal Republic of Germany were supplied by SRI International, Zurich, together with these countries' investment costs and technical coefficients. Corresponding developing country data was either supplied from field reports or estimated as described above. Prices for intermediates in all countries were taken as the calculated net cost of production for the upstream plant, e.g. ethylene oxide for ethylene glycol.

Only one size of plant and one process was studied for each product. For comparison purposes, plants using ethane, ethane propane, naphtha and gas oil were investigated as alternatives to ethane and methane feedstocks.[58/] In all cases the selected size would be considered medium to large by world standards. Downstream plants related to the output of a 500,000 t/a ethylene cracker and could therefore form the core of an integrated complex at one location. Allowing for a 90 per cent stream factor, production costs were developed using the following feedstocks and capacities:

[58/] For the cost variations possible with other processes and from economies of scale the "The Second Worldwide Study of the Petrochemical Industry", UNIDO, June 1981.

Table 34

Petrochemical feedstock costs, by-product values, utilities, and labour costs at four locations

Factor input	Location			
	U.S. Gulf Coast	FRG	Arabian Gulf	Mexico
Primary feedstocks:	$/ton	$/ton	$/ton	$/ton
methane	223	223	17[c]	25.3[a]
ethane	215	...	25[c]	25[c]
ethane-propane	198	...	90[c]	90[c]
naphtha	280	326	...	...
gas oil	245	280	...	...
Intermediates:	$/ton	$/ton	$/ton	$/ton
ethylene	423[b]	627[b]	184[b]	210[b]
ethylene oxide	626[b]	329[b]	418[b]	436[b]
ammonia	219	233	95	93[a]
By-products:	$/ton	$/ton	$/ton	$/ton
propylene (chemical grade)	419	441	400[c]	300
C-4 fraction	544	542	320[c]	400
pyrolysis gasoline	288	337	235[c]	210
fuel oil	183	210	...	...
diethylene glycol	694	758	-	-
purge ethylene	380	564	387[c]	355[c]
Utilities				
fuel, $/ton-cal[d]	0.0159	0.0182	0.00119	0.001563
cooling water, $/ton[e]	0.0139	0.0148	0.04	0.0113
steam, $/ton[f]	14.11	16.20	2.25	1.59
process water, $/ton	0.159	0.0629	0.30	0.439
electricity, mills/kWh[g]	32.40	42.90	10.00	26.00
inert gas, ¢/Nm^3[h]	2.61	6.31	-	-
Labour, $/h	15.40	17.25	10.44	6.35

[a] Market price

[b] Calculated price: net cost of production at 100% local factor

[c] UNIDO estimate

[d] Gas or low sulfur residual fuel oil with heating values 1000 Btu/standard cu ft and 18,700 Btu/lb respectively

[e] Recirculated from cooling towers at 50 psig and at 2.8° C above ambient wet-bulb temperatures; includes cost of circulating power and and treating water make up

[f] From fuel oil-fired boilers; includes distribution cost assuming 80% return to boiler house; includes depreciation on boiler (see offsites). Steam condition: 900 psig, superheated to 480° C.

[g] Prices for high voltage 8000 h/a usage

[h] On-site generation: O_2-free mixture of CO_2, N_2, and rare gases.

Plants investigated

Product	Feedstock	Capacity t/a
Ethylene	Ethane	500 000
Ethylene	Ethane-propane	500 000
Ethylene	Naphtha	500 000
Ethylene	Gas oil	500 000
Ethylene oxide	Ethylene	131 000
Ethylene glycol	Ethylene oxide	150 000
HDPE	Ethylene	75 000
LDPE	Ethylene	200 000
Methanol	Methane	640 000
Methanol	Naphtha	640 000
Ammonia	Methane	430 000
Ammonia	Naphtha	430 000
Urea	Ammonia	648 000

The resulting production cost breakdown for the four locations considered are tabulated in annex V . These results are summarized in table 35.

Sponge iron

In contrast to other product groups considered in this study, the competitivity of sponge iron in foreign markets has to be measured against the local price of an alien material - steel scrap - rather than the local cost of producing sponge iron itself. Similarly, steel produced in electric furnaces at developing country locations should be compared with steel from all sources in intended export markets.

Using the same location factors as for petrochemicals, the production cost breakdown for sponge iron and electric furnace steel are included in annex V . The respective net production costs at the four locations selected are shown in table 36. In view of the difficulty in obtaining consistent data for current sponge iron and electric furnace steel cost components, all figures should be regarded as indicative.

Aluminium

Depending on geography and infrastructure, there are several investment alternatives that can be implemented to develop a primary aluminium industry. The three most common are:

Table 35

Net cost of production for selected petrochemicals and fertilizers in four locations (1980)

Product	U.S. Gulf Coast $/ton	FRG $/ton	Arabian Gulf $/ton	Mexico $/ton
Ethylene:				
from ethane	422.47		183.69	210.84
from naphtha		626.93		
Ethylene oxide	625.83	892.45	417.52	436.21
Ethylene glycol	534.32	753.67	381.44	390.13
HDPE	678.70	920.17	438.96	449.81
LDPE	623.82	854.86	382.45	416.57
Methanol:				
from methane	213.61		69.89	68.03
from naphtha		228.20		
Ammonia:				
from methane	218.78		95.15	92.62
from naphtha		233.32		
Urea				

Source: annex V

Table 36

Net cost of production for sponge iron and electric furnace steel

	U.S. Gulf Coast	FRG	Arabian Gulf	Mexico
	$/ton	$/ton	$/ton	$/ton
Sponge iron	155.1	153.0	108.2	110.2
Electric furnace steel	423.1	452.6	369.6	301.5

Source: annex V

- an aluminium smelter linked directly to the national grid system;
- an aluminium smelter with on-site power generation utilizing combined cycle (gas/steam) turbine configurations;
- an aluminium smelter with on-site, open cycle gas turbine power generation with exhaust gas heat used in a water desalination plant.

Without prejudice to the other two, this study focuses on the third option, which has the advantage of giving three products: power, aluminium metal and potable water. The key parameters for such a complex are presented in table 37.

The main operating cost elements for primary smelters in the United States, Brazil, Australia and the Arabian Gulf States are tabulated in annex (V) and summarized in table 38.

These figures give an indication of the relative economic benefit for the countries under consideration. As with sponge iron they should not, however, be taken as anything more than a general guideline.

Table 37

Investment and operating parameters for an aluminium smelter with open cycle gas turbine power and associated desalination unit (Arabian Gulf location)

Power station:

Energy input per ton metal = 177 million Btu
Power input per ton metal = 14,500 kWh
Gas price = $ 0.25/million Btu
Power station investment = $ 158 million
Maintenance costs for power station = 2.5% of capital cost
Electricity costs = $ 0.012706900/kWh

Smelter:

Annual metal production = 150,000 t/a
Capital cost = $ 525 million
Operating cost = $ 795.12/ton metal
Maintenance costs for smelter = 2.5% of capital cost

Desalination unit:

Water production = 50,600 gal/ton metal
Capital cost = $ 260 million
Maintenance costs for desalination unit = 2.5% of capital cost

Table 38

Net cost of production of primary aluminium (1980)

	United States	Australia	Arabian Gulf	Brazil
	$/ton	$/ton	$/ton	$/ton
Primary aluminium	1 452.0	1 259.0	1 299.9	1 400.4

Chapter XI

Comparative advantages for developing countries

The main conclusion of chapter X was that, based on the assumptions used, it is cheaper to produce all twelve industrial products in the two developing countries than in nearby industrialized countries using comparable units. While this immediately substantiates the case for developing country investment to meet local demand, other factors must be taken into account—transport costs, tariffs, the cost effect of non-tariff barriers etc.—in determining the competitivity of developing country products in export markets.[59]

Transport costs

Estimates of transportation costs assume the product is shipped from a coastal production plant in a developing country to a port in an industrialized country market. From there, local distribution costs are considered equal to those of local competing producers and for comparison purposes can be ignored.

Three representative destinations are considered: New Orleans in the United States, Rotterdam in north Europe and Genoa in south Europe. Shipping distances and basic freight charges for different products are shown in table 39.

Landed vs. local price in export markets

Combining net cost of production (tables 35, 36, 38) with freight costs (table 34) gives the landed cost of gas-based industrial products from developing countries in each export market. The results for products are compared (tables 40 and 41) with the cost of local production in the United States and Western Europe.

On these admittedly simple criteria, all the selected products would be competitive in all three industrialized country markets. Part of the difference between landed and local production cost would be partly absorbed or increased in several ways—differential company overhead charges, selling costs, tariffs, discounts expected from new suppliers etc. The remainder

---

[59] In the longer term, tariffs can be considered a negotiable item; they are therefore excluded from further study. For a more rigorous approach applied to petrochemicals that includes the present cost of tariff barriers see "The Second Worldwide Study of the Petrochemical Industry", op. cit.

Table 39

Freight costs for shipping industrial products to North America and Europe in standard vessel sizes (1980)

Exporter/product	Importer					
	United States (New Orleans)		Northern Europe (Rotterdam)		Southern Europe (Genoa)	
	Distance km	Freight $/ton	Distance km	Freight $/ton	Distance km	Freight $/ton
Arabian Gulf: (Doha)	9574		6365		4510	
Ammonia		50.1		39.1		29.6
Ethylene		61.2		47.8		36.1
Methanol[a]		29.0		21.8		16.6
Urea (bulk)		54.2		41.6		33.1
Urea (bagged)		84.6		69.2		58.4
LDPE[b]		120.0		95.7		92.3
Sponge iron		12.4[c]		8.3		5.9
Steel billets		6.2		4.1		2.9
Aluminium ingot		17.7		11.8		8.3
Mexico: (Vera Cruz)	810		5137		5661	
Ammonia		7.7		28.6		48.2
Ethylene		9.4		35.0		58.9
Methanol[a]		4.0		18.6		16.6
Urea (bulk)		11.5		31.9		34.8
Urea (bagged)		31.7		58.0		66.1
LDPE (bagged)[b]		37.3		78.1		90.8
Sponge iron		1.0		6.7		7.4
Steel billets		0.5		3.3		3.7
Aluminium ingot		1.5		9.5		10.5

Source: H.P. Drewry, London

a/ Valid also for aqueous ethylene oxide and ethylene glycol
b/ Valid also for HDPE
c/ Assuming $1.30/1000 ton-km
d/ Assuming 65 ¢/1000 ton-km
e/ Assuming $1.85/1000 ton-km

Table 40

Competitivity of gas-based industrial
products in the Arabian Gulf:
landed vs. local production cost
in industrialized markets

Product	Export price $/ton	Importer					
		United States		Northern Europe		Southern Europe	
		Landed price $/ton	Local[a] price $/ton	Landed price $/ton	Local[a] price $/ton	Landed price $/ton	Local[a] price $/ton
Petrochemicals:							
Ethylene	184	245	422	232	627	220	627
Ethylene oxide[b]	417	446	620	439	929	434	929
Ethylene glycol	382	411	512	404	704	399	704
HDPE	439	559	672	535	961	531	961
LDPE	382	502	618	478	892	474	892
Methanol	70	99	214	92	228	87	228
Fertilizers:							
Ammonia	95	145	219	134	233	125	233
Urea (bulk)	86	140	169	128	183	119	183
Metals:							
Aluminium[c]	1 300	1 318	1 452	1 312	1 602	1 308	1 602
Sponge iron[c]	103	109	153	115	153	116	153
Steel[c]	370	371	423	373	452	374	452

[a] From tables X C, D and E: cost of competing product produced locally.

[b] Aqueous solutions.

[c] Pro-rated from U.S. estimates assuming 50% greater power costs.

Table 41

Competitivity of gas-based industrial products from Mexico: landed vs. local production cost in industrialized markets

		Importer					
		United States		Northern Europe		Southern Europe	
	Export price $/ton	Landed price $/ton	Local[a] price $/ton	Landed price $/ton	Local[a] price $/ton	Landed price $/ton	Local[a] price $/ton
Petrochemicals:							
Ethylene	211	220	422	246	627	270	627
Ethylene oxide[b]	436	440	620	455	929	453	929
Ethylene glycol	390	394	512	409	704	407	704
HDPE	450	487	672	528	961	541	961
LDPE	417	454	618	495	892	508	892
Methanol	68	72	214	87	228	85	228
Fertilizers:							
Ammonia	93	101	219	122	233	141	233
Urea	78						
Metals:							
Aluminium	1 400[c]	1 402	1 452	1 410	1 602[d]	1 411	1 602[d]
Sponge iron	110	111	153	117	153	118	153
Steel	302	304	423	312	452	313	452

[a] From tables X C, D and F: the cost of competing products produced locally.

[b] Aqueous solution.

[c] Equated with Brazil (table X F).

[d] Pro-rated from U.S. estimates assuming 50% greater power costs.

provides producers with their return on investment. The return for the developing country producer is higher, and vice versa where market prices in export markets rise above calculated local production costs.

Technological developments in the petroleum-based industry

In the longer term the competitivity of gas-based petrochemicals will be affected by a number of developments that at present are still in the R and D stage. Their aim is a new era in which petrochemicals are synthesized instead of cracked.

In the past 30 years, the availability of inexpensive raw materials, the important technological breakthroughs, the favourable economies offered in plant scale-up and the proliferation of new products and processes, all contributed to the huge petrochemical and nitrogenous fertilizer industries of present. The basis of this industry, however, was cracking: decomposing large molecules into simple ones. However, during the 1970s the rapid increases in the cost of those raw materials, the increasing governmental regulation, the demands for stricter pollution abatement and the on-going inflation were briging this era to an end.

In the present transition period, the high cost of raw materials, and toughening pollution standards mean that R and D will continue to focus on improving over-all efficiency of existing processes, achieving better selectivity, increasing yield of desirable products, and permitting flexibility with alternative feedstocks.

But for the industry of the 1990s and beyond, researchers are already at work creating the basis for what might be called a true synthesis industry - starting with the basic building blocks and working upwards. It is expected that the existing cracking-based industry will be inefficient and inflexible by comparison. There are presently three main lines of development for synthesis gas chemistry - all using C-1 starting materials:[60/]

(a) Modern Fisher-Tropsch technologies, involving hydrogenation of carbon monoxide to olefins and linear paraffins through catalysts in slurry reactors. Closely related is isosynthesis in which a synthesis gas mixture is reacted over thoria catalysts to produce branched hydrocarbons with high content of aromatics and naphthenes.

(b) Modern hydroformylation or oxo technology for the production of aldehydes and alcohols.

[60/] Future work will be based on C-2 starting materials.

(c) Modern carbonylation, in which reaction of carbon monoxide with unsaturated and nucleophilic compounds produces an array of intermediate products, the more important of which are acrylates and carboxylic acid derivatives.

On more conventional lines, it is expected that although current refinery cuts and gas fractions will still remain the dominant factors in petrochemicals and fertilizers during this century, three strong contenders will find a place in the longer term.

(a) Cracking of crude oil and heavy gas oil, with claimed advantages over enhanced naphtha cracking in terms of high feedstock flexibility, better olefins selectivity and lower yields for fuel products. Costs are stated to be cheaper per ton of ethylene than naphtha processing, despite higher initial investments.[61]

(b) Natural gas, from deep drilled formations beyond 5,000 meters. Recent commercial drilling proved the correctness of a long standing geological claim that large deposits of natural gas should exist below 4,000 meters. The advent of systemological surveys linked to sophisticated computers enables oil men to accurately map the deep deposits for the first time. As a result, in 1980 the United States acquired more gas reserves than it consumed for the first time in thirty years.

(c) Coal-based synthesis gas. This is being revived a time when the cheap petroleum era is over - in response to demands for feedstock flexibility based on indigenous resources. To make such plant economically feasible, it should be designed in such scale as to supply feedstocks to several basic plants like ammonia, methanol and in the future eventually ethylene.[62]

---

[61] "World Petroleum Congress and Trends in Oil and Petrochemical Industries". Chemical Economy and Engineering Review, Oct/Nov. 1979.

[62] Op. cit. in 1, "Synthesis gas: a raw material for industrial chemicals", Science, 2 January 1981, "Use syngas for olefin feedstock", Hydrocarbon Processing, Jan. 1981.

PART FOUR

CONCLUSIONS AND RECOMMENDATIONS

The ability--demonstrated in Part III of this report—to produce and ship petrochemicals competitively, is only part of the problem in exploiting associated gas. The product also has to be marketed internationally. Whether justified or not, many developing country governments regard this as the major stumbling block in their planning and it is the main reason they hesitate to commit funds to petrochemicals, fertilizers and other industrial products.

Because of the high capital outlay involved, the need to guarantee outlets for product in excess of domestic requirements can only be satisfied by one or other form of international co-operation. Whether the co-operation is North-South or South-South, the advantages of international co-operation can be mutual.

Chapter XII

Conclusions, recommendations and plan of action

Gas-based developing country producers have essentially two export options— the spot or merchant markets, and long-term arrangements for selling under contract to users or distributors.

Normally not more than 25 per cent of plant output can be left subject to the risk of selling in spot markets. The rest must be sold under long-term contracts (i.e. two years or more).[63] But while such co-operation between producers in developed and developing countries and among the developing countries are still exceptional.

Each product group requires a different type of co-operation. Fertilizers are a deficit item in developing countries and would therefore employ South-South co-operation. Primary oil intermediate petrochemicals, likewise aluminium, would involve co-operation with industrialized country producers that at present have most of this production capacity. Final products such as plastics call for a mixture of South-South and North-South co-operation.

Logically the type of co-operation reflects the relative ease and difficulty in marketing the particular product. Methanol, which is a bulk commodity, can be sold to small numbers of consumers at one internationally recognized specification. Low-density polyethylene, on the other hand, runs to hundreds of grades and sells to several thousand plastic producers in each country. In all cases co-operation involves one of four approaches:

- long-term supply arrangements;
- product specialization and exchange agreements;
- jobbing contracts;
- agency sales arrangements.

The arrangements can be envisaged in the context of:

- joint ventures for production and marketing;
- joint ventures for marketing alone;
- non-equity joint ventures;
- regional co-operation agreements;
- long-term government-to-government and enterprise-to-enterprise co-operation.

---

[63] The minimum for contracts sales varies by product depending on plant production economies.

The need for incentives

In the long term market forces will probably redistribute production capacity according to the laws of comparative advantage. However, because traditional petrochemical producers are unlikely to redeploy capacity until forced to by feedstock shortages, the timing of such changes is unlikely to conform to the immediate needs of developing country producers. Developing countries looking to industrial co-operation as a means of rapid industrialization may therefore offer incentives to potential foreign partners in order to speed up the process.

As oil and gas producers, oil-producing developing countries can offer various types of incentive for industrial co-operation:

- feedstock at favourable prices;
- low-cost loans;
- intermediates at favourable prices;
- access to local markets;
- access to other export markets;
- access to non-chemical commodities, e.g. crude oil;
- equity investment in the foreign partner itself;
- tax incentives (e.g. tax holidays).

The OPDC producers' task is to put together a package of these incentives that attracts the right kind of foreign partner without at the same time conceding too much of the economic rent due to themselves as owners of scarce, non-renewable resources.

The justification for providing such incentives is the same as that for building up the related infrastructure: the added value of the country that uses rather than burns associated gas is considerable. Even more important in the long run are the benefits of industrialization - the acquisition of skills and know-how in preparation for the day when non-associated gas and other resources have to replace income lost from declining oil production. In that sense, even a break-even or less-making venture could be considered worthwhile.

General Conclusions

The review of the availability of associated gas, flaring practices and country utilization plans (Part One) showed that although gas flaring is widely recognized as a waste in principle, it will take a long time before it can be brought under control in practice. At present, only five per cent of the gas produced in the 18 countries studied was being used by the process industries (table 4). The opportunities for using it in an export context are summarized by number of new plants that will have to be built somewhere to satisfy world demand in 1990:

Product	No. Plants
Ethylene	16
LDPE	32
HDPE	39
PVC	26
Methanol	7-14
ammonia	44
aluminium	60-70
LNG	20-32

Of the gas-based industrial products selected for detailed study, all show satisfactory long-term export prospects and nearly all can be produced economically in developing countries given suitably low prices for the gas raw material. Inclusion of shipping costs indicates that all these products can also be shipped competitively with locally produced materials to Europe and the United States.

The main problems are therefore those of market access and technology transfer. In this connexion, it has to be recognized that even in good times the petrochemical world has not been beating a path to associated gas producers' doors. Barring a handful of oil majors attracted by oil incentives, the numbers are not encouraging. This may be a case of the cautious waiting on the performance of the bold before taking action themselves, but it is hardly in line with the recommendation of the First Consultation on Petrochemicals that new capacities be built in developing countries and that the international petrochemical industry assist in various ways.[64] Solving the flared gas problem could, then be regarded as a test of will. The basic economies of using flared gas recovered at a price of 40 cents per million Btu or less are such that if the developing countries cannot succeed in penetrating world markets on this basis, then they will succeed in no other. In the words of one commentator they will be condemned "to a permanent role as hewers of wood and drawers of water".[65]

---

[64] UNIDO WG 336/2

[65] Louis Turner, op.cit., p. 79

Recommendations

1. Petrochemical producers in industrialized countries actively encourage addition of new capacity and replacement of old capacities by means of investments in and long-term co-operation arrangements with developing countries where associated gas is available.

2. Governments and producers in developing countries study ways to improve security of supply under long-term co-operation arrangements. This should include regional back-up in supply and shipping.

3. Governments and producers in industrialized countries consider ways to ensure orderly marketing arrangements with developing country suppliers so as to absorb their capacity with minimum disturbance to existing world markets.

4. A further study of potential South-South co-operation based on associated gas from OPDCs, (a) in the context of market size and mutual exchange or use of raw materials, e.g. energy versus bauxite or alumina, and (b) in the context of development aid to non-OPEC developing countries, e.g. fertilizer supplies.

5. Elaboration of the procedures used in the present study to evaluate not only the competitivity of gas based industry, but also relative profitability in particular cases. This would take two forms: (a) an information and evaluation package enabling developing country planners to collect and manipulate data on their own, and (b) a UNIDO service in which data supplied by developing countries would be used to calculate the value added, return on investment and/or net back value of the gas used for specific projects.

ANNEX I

Recovery of liquids from associated gas[66]

As an example of the costs involved in recovering gas **components—ethane**, propane and butane—from associated gas, the following calculations apply to a rich gas feedstock in Texas, United States, with the composition shown in table A.I.1. The composition is close to that for associated gas in Saudi Arabia.

There are three possible processes for gas liquids recovery:

1. Expander - cooling by means of an iso-entropic turbine.
2. Cascade refrigeration - refrigeration on a number of levels.
3. Refrigerated absorption.

Because expander type plants are generally favoured for new projects, this technology has been assumed for the calculations. In fact, however, liquids recovery costs are much the same for all three processes.

Liquids recovery costs are calculated assuming:

- * inlet associated gas has zero value
- * residue gas (methane and ethane) has zero value
- * utility values as for the petrochemical calculation (table 00)
- * costs as for an Arabian Gulf location in mid-1980
- * plant size: to treat 4.72 million cu m/d

Three cases are considered—cases A and B with an ethane recovery of 86 per cent, case B showing more up-to-date (higher) capital costs; case C with a recovery of 50 per cent.

---

[66] Contribution by GOIC based on data from SRI International, Zurich.

	Case A	Case B	Case C
Ethane recovered, per cent	86	86	50
Liquids recovered, t/a	518 000	518 000	301 700
Plant investment, $ million			
Battery limits	50.35	66.60	44.07
Offsites	19.36	25.70	15.49
	69.71	92.30	59.56
Average liquids recovery cost:	$/ton	$/ton	$/ton
Bare cost[a]	40.87	51.82	44.34
Interest on working capital and start-up costs (5%)	1.08	0.39	0.98
Interest on 50% of total fixed capital (5%)	3.36	4.34	3.74
	45.31	56.55	49.06
25% return on investment	33.74	44.67	37.32
Total	79.05	101.02	86.38

---

[a] A world-scale, 500,000 t/a plant requires approximately 625,000 t/a of ethane as feedstock. Hence a much larger plant than this example would be needed. However, two or three smaller plants could also be considered.

Based on cases A and C, the liquids recovery would be as follows:

	Case A	Case C
Ethane recovery, per cent	86	50
	t/a	t/a
Ethane	625 000	625 000
Propane	388 277	631 393
Butane	208 712	350 579
C_{5+}, gasoline	119 439	206 824
Total liquids	1.341 428	1 813 796
Gas inlet volume, million cu m/d	12.2	21.1

It can be seen that recovery costs are not greatly affected by the percentage ethane recovery. Hence the percentage recovery actually chosen is likely to be dictated by overall marketing consideration—in particular, the sales prospects for propane and butane.

The value of ethane

From the above calculations, average liquids recovery costs are as follows:

	Case A	Case B	Case C
Average liquid recovery cost, $/ton	79	101	86

Since these are average costs, the recovery costs for the other liquids if ethane is assigned zero value are:

	Case A	Case B	Case C
Average recovery cost for C_3, C_4 and gasoline, $/ton	148	139	131

Since none of these products has an f.o.b. value much less than $300/ton, an ethane value of zero is perfectly possible. In effect petrochemical operations would be subsidized from LPG sales. To be realistic, however, it costs money to transport the ethane from the recovery plant to the petrochemicals site. Taking other administrative charges into account, ethane in this study has been assigned a minimum value of $ 25/ton (55 ¢ /million Btu).

ANNEX II

GAS UTILIZATION PLANS IN 18 DEVELOPING COUNTRIES

ALGERIA

Produced in Algeria since the mid 1950s, gas output in 1978 reached a level of 89 million cu m/d, of which 14 million cu m/day were re-injected. With less than 5 per cent sold or consumed locally, over 60 per cent was flared.

Government policy on exploitation of natural gas reserves is changing with new priorities assigned to national development. An ambitious industrialization programme ("Valhyd"-Hydrocarbon Development Plan for Algeria, 1976-2005) is being scaled down as part of a general shift away from heavy industry in favour of agriculture, housing and other social developments. Industrialization--the massive investment in LNG projects in particular--is considered to be consuming an unwarranted proportion of the country's capital reserves.[67]

The impact of these changes on the gas and petrochemical sector is twofold. Two LNG projects and a gas collection pipeline have been cancelled; at the same time gas exports via a new transmediterranean pipeline are being promoted and a proposal to double its capacity was due for decision by the end of 1980.

Gas-consuming industries in Algeria include petrochemicals (ethylene, methanol and PVC), fertilizers (ammonia), iron and steel, cement, glass and general chemicals. Counting power generations and home use, national consumption amounted to 14.1 billion cu m in 1978.

Under the Hydrocarbon Development Plan the revenues from oil and gas exports were to be used to create an independent and viable infrastructure for Algeria. The resulting steel mills, vehicle plants, textile mills, petrochemical plants and electrical equipment factories would have further increased local demand for gas. All these projects as noted, are currently under review.

67/ Mid East Markets, 26 January 1980

The largest single user of gas is the LNG industry. In 1978 Algeria exported 6.4 billion cu m of gas as LNG. At the time it had export contracts for future supplies adding up to 64 billion cu m/a—52 billion cu m as LNG and 12 billion cu m by pipeline. With the abandonment of two proposed LNG production units total capacity will reach only 42 billion cu m/a, when the third Arzew line comes fully on stream in 1984. The difference may be made up either by not resuming deliveries to the United States or by doubling pipeline deliveries to European customers.

With rising LPG prices, low transportation and relatively low extraction costs compared to LNG processing, Algeria's LPG and condensate projects are also set to become major revenue earners. Current production at Hassi Messaoud (1.28 million t/a LPG, 50,000 t/a propane and 106,000 t/a butane) and Arzew (butane 350,000 and propane 600,000 t/a) is supplemented by small quantities available from the LNG units. New turboexpanders are being installed at Alrar, Mereksen, Stah, Hassi-R'mel and Rhourde Nouss. LPG will also be produced as a by-product of the LNG II unit at Arzew.

Overall assessment

Prior to 1978 Algeria only exported non-associated gas, reserving most of its associated gas for re-injection. Associated gas was scheduled to become a source of pipeline gas when production exeeded re-injection requirements in the early 1980s.

In practice the conservation limits placed on oil production will curtail associated gas availability. Nevertheless even under a curtailed export programme, demand for LNG and pipeline gas will considerably exceed the quantity available as associated gas and solving the overall flaring problem will become a matter of internal adjustment. Industrial use of natural gas could therefore proceed at a pace indicated by domestic needs rather than the need to exploit a wasting asset. What remains uncertain is whether the ethane component of the associated gas will find optimal uses.

BAHRAIN

In 1978 Bahrain's associated gas output reached 12.6 million cu m/day of which 2.5 million cu m (20 per cent) was flared and 2.7 million cu m was re-injected.

With an oil output of only 57,000 b/d and reserves of 200 million bbl, Bahrain is one of the least endowed oil producing countries in the Arabian Gulf. Government industrial strategy therefore emphasizes cooperation with neighboring states. The gas-based joint ventures in petrochemicals and sponge iron (see below) link Bahrain with Kuwait, Jordan, Iraq and Saudi Arabia.[68] Six Gulf states are to co-operate in an aluminium rolling mill to be built in Bahrain[69], and Bahrain also considered a stake in a Gulf project to manufacture cement in Saudi Arabia.

Since 1979 responsibility for processing associated gas has been vested in the Bahrain National Gas Corporation (BANAGAS), a joint venture between the Bahrain National Oil Company (75 per cent), the Arab Petroleum Investment Corporation (12.5 per cent) and Caltex (12.5 per cent). The joint venture operates a 2.8 million cu m/day, NGL plant producing 80,000 t/a, propane 75,000 t/a butane and 125,000 t/a natural gasoline, all marketed by Caltex. Projected earnings are estimated at $33 million per annum. The plant produces a residual gas containing ethane and methane at a rate of 2.4 million cu m/day.

Main gas users are presently Aluminium Bahrain, a power station and an oil refinery. Between them they account for around 7 million cu m/day. In 1980 government approval was obtained for a $350 million plant to be built by the Arab Iron and Steel Co., a joint venture between Bahrain, Kuwait, Iraq and Jordan. The plant will come on stream with a capacity of 400,000 tons per annum of pelletized iron in 1983-84.[70] Gas consumption is estimated at around 2.5 million cu/day.

Another Arab joint venture in Bahrain, Gulf Petrochemical Industries Co., plans a $400 million project to produce 100,000 t/a each of ammonia and methanol.

---

[68] Mid-East Markets, 25 August 1980

[69] Saudi Arabia also provides 100,000 b/day for Bahrain to produce in its joint venture oil refinery with Caltex.

[70] Mid-East Markets, 16 June 1980

Overall assessment

With these new plants for ammonia and methanol, there should be sufficient utilization capacity to cease flaring associated gas. Further gas-based industrialization would therefore proceed on the basis of Bahrain's reserve of non-associated gas. On the other hand, no arrangements appear to be being made to utilize the ethane content of the associated gas for its chemical value.

BRUNEI

Oil and LNG exports are the mainstay of Brunei's foreign trade, bringing in $1.6 billion in 1978. Oil production has levelled at 230,000 and 250,000 b/d giving an associated gas output of around 35 million cu m/day. Of this, 11 million cu m (31 per cent) were flared, and none re-injected.

Government policy on exploiting both associated and non-associated gas is limited by lack of skilled manpower in a population of only 213,000. At present there is only one project, a 6 million t/a LNG unit whose output is dedicated under 20-year contracts to consumption in Japan.

The plant consumes around 20 million cu m/day i.e. nearly all the associated gas that is not being flared. Owned and operated by Brunei-LNG Limited, in which the state now has a 33 per cent share along with Mitsubishi and Royal Dutch-Shell, the plant buys gas from Brunei-Shell Petroleum Co., a 50:50 joint venture between the Brunei government and Shell group. The LNG is sold to Coldas Trading Limited, a 50:50 joint venture between Shell and Mitsubishi, which ships it to Japan.

Although further industrial development in the field of petrochemicals and fertilizers was considered under the last five-year plan, there are no projects of this nature in the present 1980-84 plans.

Overall assessment

Without further industrialization, Brunei associated gas will continue to be flared at around the 30 per cent level. Brunei also loses potential revenue through low contract prices; Brunei-Shell Petroleum receives only 20.1 cents/million Btu for the gas sold to the LNG plant, while the price in Japan for the 70 per cent of the deliveries is only 48.6 cents/million Btu.

are being negotiated for additional supplies; deliveries to the United States have yet to start. Both plants are scheduled to double their capacity by 1985

NGL-LPG recovery plants are in operation in North Sumatra, West Java, East Kalimantan. In most cases the LPG production is exported directly, natural gas liquids are spiked into crude oil and the residual gas is used for industrial purposes e.g. fertilizers and steel production.

Fertilizers have been produced in Indonesia since 1958 with strong emphasis on urea. By 1979 urea capacity reached an estimated 2 million t/a and it should exceed 3 million t/a in 1983. Two recent additions feature international co-operation: a unit at Kujang, West Java was financed with a $2 million loan from Iran; a 570,000 t/a at Aceh in North Sumatra is being built as joint venture by five ASEAN states and partly financed by a $3 million low interest loan from Japan.

Two petrochemical projects based on gas are $1.5 million complex to be built at Aceh and a $300 million, 350,000 t/a methanol unit at Bunya Island. The Aceh development includes an ethylene cracker (300,000 t/a), low-density polyethylene (285,000 t/a), high-density polyethylene (60,000 t/a), VCM (110,000t/a) and ethylene glycol (70,000 t/a). The project, which should save Indonesia from $200 million on imports annually is being discussed on joint venture terms with Union Carbide, Exxon, Phillips Petroleum, Cdf Chimie and Mitsui[71] Feedstock prices for these plants are understood to be somewhat about the 65 per million Btu currently paid by domestic gas users.

Overall assessment

In principle Indonesia is well on the way to solving its flared gas problem. In practice, however, a large amount of rationalization is needed before industrial users can be supplied preferentially with associated gas that would otherwise be flared rather than non-associated gas that could be left in the ground.

---

[71] Chemical Week, 19 March 1980

The remaining 1.5 million t/a is sold at 90 cents/million Btu i.e. well below world rates.[72]

A further loss is represented by the practice of re-injecting ethane, propane and butane components back into the LNG.

INDONESIA

Despite regulations to control flaring[73] and a number of gas-based industrial projects, in 1978 Indonesia was still burning the equivalent of nearly 35 per cent of its associated gas - 17 million cu m/day out of a production of nearly 50 million cu m/day. Provisional data for more recent years indicate, however, large improvements due to greater utilization by industries and increased re-injection. Together, this measure may have brought the flaring rate down to 22 per cent of associated gas production.

Government policy, embodied in Indonesia's third five-year plan (1979 to 1984) emphasizes three changes: a) greater use of gas for industrial and home needs, b) use of both associated and non-associated gas to make Indonesia sufficient in basic petrochemicals and fertilizers by 1985, and c) substitution of gas for oil in the economy to reduce oil imports.[74] This is taking concrete form in the expansion of two LNG plants and a number of petrochemical projects (see below). Several of the projects under discussion could involve co-operation with industrialized countries and with other developing countries. The Indonesian partner in such cases would be Pertamina, the state oil and gas agency.

Gas utilization projects are found at four sites: North Sumatra (LNG, fertilizer, petrochemical, LPG-carbon black, power generations); South Sumatra (fertilizers, power generations, LPG); West Java (LPG, NGL, steel, urea, cement) and East Kalimantan (LNG, urea, NGL, and LPG).

Indonesia's largest users of natural gas are the LNG plants at Arun and Badak. Owned by Pertamina, they are operated by joint companies in which Pertamina has 55 per cent, a Japanese consortium (the ultimate consumer) 15 per cent, and a third partner from the United States—Mobil Oil for Arun and Huffco for Badak—the remaining 30 per cent. Under 20-year sales contracts, LNG is designated for Japan (7.5 million t/a) and United States (4.5 million t/a). Japan currently pays $4.95/million Btu but higher prices

---

[72] Chemical Engineering, 12 Nov. 1973, 113.

[73] Gas flaring has been regulated in Indonesia since 1960 under a law requiring re-injection to be given first priority in order to maximize oil production.

[74] Although Indonesia is a net oil exporter, large quantities are imported because local refineries are unable to process Indonesia's heavy crudes to provide sufficient middle distillates.

Gas demand in 1978 assuming the LNG plants had been running at full capacity was 58 million cu m/day, i.e. close to Indonesia's total gas production. By 1985, following further expansion of fertilizers and petrochemicals production, demand will exceed 100 million cu m/day. This will require all the available associated gas plus supplemental supplies from non-associated sources.

With only one major user, however, there is considerable room still for plants to use the ethane component of different gas streams for petrochemicals.

IRAN

In 1978 Iran flared 47 per cent of its associated gas - 66 million cu m/day out of 151 million cu m/day produced. At that time oil output was 5.25 million b/d making the country the world's second largest producer. Over 27 million cu m/day were re-injected, 26 million exported as pipeline gas to the Soviet Union[75] and 26 million cu m/day used domestically.

At that time, the government had ambitious plans for industrialization and Iran's gas resources were to have play a major role. Given the political changes since 1978, it is unlikely that these plans will be realized with more than a fraction of their original scope. Nevertheless Iran's intentions stand out as an object lesson in what may be done with flared gas—and the strains they may place on the economic and social fabric of a country if pushed too fast.

Building on existing experience, gas was to develop as a resource of broadly equivalent importance to oil. In addition to direct exports, utilizing it most productively meant employing gas as feedstock for petrochemicals and as an energy source for energy intensive industries. The overall object was to move Iran up the scale in the international division of labor. Foreign partners were welcome in relation to their ability to provide modern technology and market access.

---

[75] The IGAT I pipeline permitted direct export of gas at the low price of 18.2¢/million Btu in return for Soviet assistance in constructing a steel mill, a heavy machinery plant, a machine tool factory and supply of military equipment. The price was eventually raised to 76¢/million Btu as of January 1977.
The IGAT II pipeline, originally anticipated for completion in 1980, was part of triangular Iran-Soviet-European arrangement. Iran would have supplied the USSR 46.5 million cu m/day for use in neighboring Azerbaidjan, Georgia and Armenia, releasing an equivalent quantity in its northern fields for use in Western Europe. From a strategic view point it is interesting to note that the Soviet Union insisted on a high calorific value in the Iran deliveries, thereby ensuring that most of the ethane was not removed.

Although three attempts to export gas in the form of LNG foundered—largely because world prices were considered too low—Iran has developed a substantial export programme based on NGL processing. Two existing NGL units, at Kharg Island and Bandar Ma'shur, had a combined capacity of 1 million t/a[76], a plant under construction at the Bandar Khomeni[77] — part of Iran's joint venture with Mitsui and other Japanese companies — would have had a capacity of 2 million t/a. In addition the Kharg Island facility was to have had extra 750,000 t/a capacity by 1981 and Bandar Khomeni had meanwhile been selected as the site for a second facility, adding a further 1.8 million t/a. If all these projects had been realized, Iran's total LPG capacity would have been 5.8 million t/a by mid 1980s. This compares, however, with 10 million t/a considered possible, if all gas currently flared were processed in NGL units.[78]

In petrochemicals, responsibility for the $3.5 billion investment envisaged under the 1975-80 plan was vested in the National Petrochemicals Corporation (NPC). NPC's partners in all cases came from industrialized countries: B. F. Goodrich (PVC), Amoco (sulphur and LPG), Cabot (carbon black), Allied Chemical (fertilizers), Nissho-IWAI Mitsubishi chemical (plasticizers) and the Mitsui group (olefins, chlorine, ethylene dichloride, low-density polyethylene, high-density polyethylene, polypropylene, synthetic rubber, butadiene, benzene and LPG initially; styrene and xylenes later)[79]. Key attraction for these partners must have been the extremely low gas price reported: 2¢/million Btu.[80]

Energy-intensive industries were also being developed. In addition to an existing 110,000 t/a aluminium smelter, iron and steel production capacity was to be expanded with a 6 million t/a sponge iron complex. Cement capacity was to be nearly doubled with an additional 2.7 million t/a.

Overall assessment

Whatever the industrialization policy adopted by Iran's future Government, the key to solving the flared gas problem is the size of direct exports as pipeline gas, and of the eventual gas-re-injection programme in relation to oil output. In 1978 when oil production was over 5 million b/d, re-injection

---

[76] A further 400,000 t/a was available from Iran's refineries.

[77] Throughout this text this facility is referred to under its current name.

[78] S. Boushahri, Kharg Chemical Co., Teheran *Gas-Tech*, 1978

[79] In 1979 the first phase of the Mitsui joint venture was 85 to 90 per cent completed when construction stopped. Negotiations either to re-start construction work on all projects or to confine attention to the LPG units have since broken down.

[80] Nominal well-head price, pre-1973. Later considerations allowed for prices from 2¢ up to $1.00/million Btu linked to company profitability. See Louis Turner, *Mid-East Industrialization*, Royal Institute of National Affairs, 1979.

accounted for 19 per cent associated gas output. Reportedly there were plans to increase this[81] — presumably in relation to a larger oil production rate.

Assuming that these plans will be partially realized but that future oil production rate will be at levels substantially below those in the past, all associated gas could be processed in NGL units. The LPG could be recovered for export and the residual gas re-injected to boost oil recovery and to store gas for future use.

Realization of earlier plans for petrochemicals production, while not diminishing the total value of flared gas significantly, would begin to make better use of its ethane component.

IRAQ

In 1978 Iraq produced 30 million cu m/day of associated gas in connection with an oil output of 2.6 million b/d. At that time none of this gas was re-injected and some 25 million cu m/day (84 per cent) was flared. With five new oil fields opening up - bringing potential output to 4 million b/d - the flaring problem could however increase despite government plans aiming at 80 per cent utilization by 1980.

Greater reliance on gas as an energy resource to conserve oil for industrial and domestic uses is central to Iraq's development strategy. Processing therefore emphasizes LPG recovery for local use, with residual gas going to industry, and only excess quantities of LPG being exported. The Iraq domestic market is considered large enough to utilize all the estimated gas resource in the next four years, thus ruling out exports in the form of LPG.

Under the auspices of Iraqi State Organization for Oil Production and Gas Distribution, two separate gas gathering and processing projects are under way. In the south the network focuses on an 8 million cu m/day gas separation unit at Khor-Al-Zubair completed in 1978. (Utilization of residual gas from this facility is discussed below.)

---

[81] S. Boushahri, *op. cit*

In the north an existing 285,000 t/a LPG plant near Baghdad supplies residual gas to a power plant and cement factory. In 1981 this will be expanded with completion of 1.5 million t/a LPG unit handling an additional 20 million cu m/day of associated gas.

Direct use of associated gas in the south began in 1965 with a line to the Basrah power station. Iraq's first fertilizer complex (ammonia, 60,000 t/a; urea, 56,000 t/a; ammonium sulphate, 120,000 t/a) came on stream at Abu Flus in the early 1970s. Later expansions brought ammonia capacity to 82,000 t/d.

Gas utilization in the south will be increased with the availability of residual gas from the Khor-Al-Zubair NGL unit to supply an iron and steel complex, a petrochemical unit and a second fertilizer site. Sponge iron capacity in the steel complex will eventually reach 1.25 t/a; Iraq's first petrochemical complex will include ethylene (130,000 t/a), low-density polyethylene (60,000 t/a), high-density polyethylene (30,000 t/a) and PVC (60,000 t/a). The fertilizer complex will produce 2,000 t/d ammonia and 3,000 t/day urea.

Overall assessment

Incomplete data on individual industrial uses preclude a full picture of how flaring will be reduced. As a first approximation it can be seen that the three NGL units could consume up to 25 million cu m/day. When they are fully loaded, this means that the government commitment to 80 per cent utilization in the early 1980s will be realized, if uses can be found for the residual methane and ethane. As noted, however, gas availability could at the same time rise by 55 per cent with expanding oil output In addition, with only one relatively small ethylene cracker in the offing, ethylene utilization would remain poor.

KUWAIT

In 1978 all of Kuwait's output of natural gas 30 million cu m/d, came in association with the country's output of 2.1 million b/d of crude oil. Including gas used for re-injection, utilization level in that year reached 62 per cent, already one of the highest in the Middle East. Since then, the completion of a second NGL plant has cut flaring to the practical minimum.

Development of gas, oil refining and petrochemicals form a major part of Government plans to develop and diversify Kuwait's sources of income.[82] If however the high oil output (e.g. 2 or 3 million b/d) cannot or should not for conservation reasons be sustained, the total quantity of gas for industrialization purposes will be limited. Future expansion will likely emphasize better types of utilization, e.g. chemical rather than fuel use of ethane.

Although Government strategy allows for co-operation with partners in industrialized countries, there are none so far in petrochemicals or fertilizers in Kuwait itself. Co-operation with other developing countries in joint ventures outside Kuwait has been more successful. With Bahrain, for example, it established Bahrain-Kuwait Petrochemical Industries in Bahrain in 1979. The first project is a 1,000 t/d ammonia and a 1,000 t/d methanol complex at Sitra, Bahrain using locally available gas. The products will go mainly to China and the Indian subcontinent.[83]

All new projects using gas as feedstock or fuel domestically are evaluated by the Kuwait Oil Ministry. To proceed they must be approved by both the Kuwait Petroleum Council and the Government's Priorities

---

[82] Kuwait's limited possibilities for industrial and agricultural development and the need to prepare for the post-petroleum era are the reasons for the creation of a "reserve fund for future generations", using it to invest surplus oil revenues abroad. In France Kuwaiti assets include participation with Cdf Chemie in a urea project at Toulouse. Further co-operation between the partners is under discussion. **Mid East Markets**, July 14, 1980.

[83] Mid East Markets, August 1980. Kuwait is also considering participation in the financing of an oil refinery at Batam, Indonesia. Agreement in principle with Indonesia and Malaysia for a 200,000 b/d refinery using Kuwaiti and Indonesia crudes was signed in 1977. An aromatic project proposed to other Arabian Gulf partners failed to get off the ground.

committee. Projects are ultimately built and managed by Kuwait Petrochemical Industries (KPIC) or Kuwait Chemical Fertilizer Company (KCFC).

LPG output from NGL units at Mina al-Ahmadi and Shuaiba is mostly intended for export. Maximum capacity of the two units together is 6.85 million t/a but crude oil output could restrict this to around 4 million t/a. Of this, by July 1979, 1.5 million t/a had been committed as exports, mostly to Japan, under long-term contracts.

Kuwait's first gas-based industrial complex has been making ammonia, urea, ammonium sulphate and sulphuric acid at Shuaiba since 1966. In 1978 KCFC's ammonia output reached 523,000 t/a and urea 668,000 t/a84/. A further 1000 t/d ammonia capacity, partly replacing an old plant, is due on stream in 1981.

KPIC, meanwhile, is studying an ethylene complex making 350,000 t/a ethylene together with a downstream units for low-density polyethylene, ethylene glycol and styrene. There are also plans to nearly double power generating capacity by 1985, partly to supply a new 120,000 t/a aluminium smelter.

Overall assessment

After peaking at over 2 million b/d in 1979, oil production has been reduced as a conservation measure to 1.5 million b/d, with a corresponding gas output of around 23 million cu m/day. On this basis, Kuwait is heading for a position of tight gas supply. Flaring should thus be maintained at the minimum necessary for oil field operation and increased supplemental gas supplies taken from non-associated sources in Kuwait's offshore neutral zone.

The data are insufficient to determine if ethane will be fully used in the proposed new cracker.

84/ "Arab Oil and Gas Directory", 1979/1980

LIBYA

According to official figures the Libyan Jamahiriya already has one of the lowest flaring rates: 14.5 million cu m/day out of a 1978 production of 58 million cu m/d (20 per cent).

Government strategy for exploiting gas reserves explicitly gives preference to industrial use of associated over non-associated sources. A gas gathering pipeline is being built linking small but scattered fields to permit either industrial use or re-injection. The authorities have hesitated, however, to move quickly into industrial projects - at one time rejecting a mega-methanol project in favor of re-injection. Gas utilization is nevertheless embodied in the General National Organization for Industry's strategy development plan for 1980 to 2000.

According to this there will be nine major industrial areas for chemical and petrochemicals: at Marsa el Brega (methanol, ammonia, urea and naphtha-based ethylene); Ras Lanuf (refining, ethylene toluene, xylene, chlorine, magnesium, methanol, VCM); Ben Jawad (paints pesticides, plastics); Ajedabia; Surt (iron foundry and forge); Abu Khamash (VCM); Zuara (refining and fertilizers, aluminium smelting and fabrication); Zawaia (refining and fertilizers); Tajiura (steel fabrication, auto industry, food production, light industry); Marada (brine extraction).

Despite ten years' experience in LNG production, the authorities appear uninterested in expanding that business. The plant at Marsa el Brega processes 15 million cu m/d of both associated and non-associated gas to make LNG, LPG and NGL. Exports are mainly to Spain and Italy. Over the years Libyan LNG prices have risen from 49¢/million Btu to $1.62/million Btu f.o.b. Marsa el Brega; policy is now to link them to OPEC oil prices.

Industrial utilization of natural gas is the responsibility of the Libyan National Oil Corporation which runs ammonia and methanol plants at Marsa el Brega. The ammonia plant, with a capacity of 1,000 t/d exports to Italy, Greece and Spain pending completion of a 1,000 t/d urea unit. Sales are handled by a Bermuda-based shipper.

The methanol plant is a joint venture between National Oil Corp. of Libya and Occidental Libya. All the output of the 1,000 t/d is exported; mainly to Southern Europe.[85]

Future units using natural gas include a direct reduction iron and steel plant at Misrata, a second ammonia unit at Marsa el Brega, a petrochemical complex at Ras Lanuf using gas as a fuel, two additional 1,000 t/d ammonia units at Ras Lanuf and possibly Misrata, and a 100,000 t/d aluminium plant at Zuara. Increased gas consumption for power and water desalination is also planned.

Overall assessment

In line with reductions in oil output, Libya's associated gas production is scheduled to decline. Estimated output will drop from 41 million cu m/day in 1980 to 30 million in 1985 and 22 million in 1990. With the increase in demand from steel, aluminium, power generation and general industrial plant, not only should flaring be eliminated by 1985, but there will also be a need for nearly double the present consumption of non-associated gas.

---

[85] Both methanol and ammonia are delivered to Greece as part of the $4 million/year trade agreement under which Libya supplies Greece with 1,000 t/a of ammonia, urea and methanol in exchange for complex fertilizers, agricultural machinery, medicine and cement. Fertilizer International, March 1979, p.1. Greece will also receive a 3 million t/a oil allocation and the two countries are exploring the possibility of a joint venture ammonia plant in Libya. ECN, 10 January 1979

Exports of 50,000 to 60,000 t/a are reported under a negotiation with four Japanese producers to substitute or replace their butane with natural gas-based output.

MALAYSIA

With a modest oil output, Malaysia produces only a small quantity of associated gas and virtually all of its flared. In 1978 output was around 11 million cu m/d in conjunction with a crude output of 210,000 b/d.

The Malaysian Government has always pursued a cautious approach into exploiting the country's oil and gas reserves, but under the 1981-1985 Plan, a number of petrochemicals and energy-intensive projects based on gas are firming up. A common feature running through them is partnership with foreign firms in joint ventures.

An LNG plant at Bintulu in Sarawak is due on stream in 1983 with a capacity of 6 million t/a. Output is destined for Japan under 20-year contracts. The plant will consume 24 million cu m/d of non-associated gas from an offshore field. Costing $2.4 billion the project is a joint venture between the national oil agency, Petronas (65 per cent), Royal Dutch/Shell (13.5 per cent) and Mitsubishi Co. (13.5 per cent).

Using the same gas source, a joint venture 1500 t/d urea plant is being built by members of the ASEAN group. Malaysia will hold 60 per cent, Indonesia, Thailand and Philippines, 13 per cent each and Singapore 1 per cent.[86]

Likely future projects include 1500 to 2000 t/d methanol plant using associated gas from offshore fields. This may be set up as a joint venture to take care of the exportable surplus.

Whether Malaysia uses its natural gas resources for steel or aluminium industry is the subject of an ongoing debate. Gas from offshore fields at Sabah and Sarawak was earmarked for 900,000 t/a aluminium smelter on the Island of Labuan. The project would have been a joint

---

[86] Chemical Week, 19 March 1980

venture between Aluminium Pechiney, France (30 per cent), Hyundai, South Korea (15 per cent) and the State Governmet of Sabah. It apparently foundered[87] on a doubts over the size of the gas fields to be used and a desire for a more viable downstream industry. For this reason feasibility studies on sponge iron are now being carried out as an alternative.

A second, smaller, smelter (100,000 t/a) is under consideration at Bintulu near the LNG and urea plants by Reynolds Aluminum of the United States.

Overall assessment

To date only one large project - for methanol - is slated to use associated gas and there are none designed specifically to recover gas components separately, e.g. ethane for petrochemicals, LPG for export. Nevertheless the relatively small quantity gas being flared means that when the LNG plant and other large users are in operation, their consumption will far exceed the flaring losses. The Malaysian problem will then become one of the rationalization: building pipelines to transport associated gas into the larger end users to conserve other energy sources.

MEXICO

In 1978, Mexico produced 72.5 million cu m/d of gas including that associated with 1.21 million b/d of oil. Flaring rate was one of the world's lowest: around 20 per cent of associated gas and 7 per cent of total natural gas.

Because Mexico—perhaps uniquely among the oil producing countries—regards flared gas as a political as well as economic issue, no effort is spared to reduce this level still further. Completion of pipeline to collect offshore gas in the Gulf of Campeche was designed to cut the overall level to 3 per cent. Further reductions were to follow as a result of a case-by-case study by Instituto Mexicano de Petroleos on the most economical way to use small quantities of gas flared at isolated wells.

[87] Far Eastern Economic Review, 18 April 1980

Faced with prospect that flaring problems could put a brake on oil production levels, government strategy for continuing to utilize the associated gas effectively plays on three options: increased domestic consumption (incidentally releasing exportable oil products), increased re-injection, and increased exports (via pipeline to the United States).

In March 1980 distribution by pipeline was extended to the United States border to permit direct export at a rate of 8.5 million cu m/d. The reported price was $3.625/million Btu, to be adjusted quarterly in line with the average of a basket of five crude oils.

Mexico had already stepped up its re-injection programme to reduce flaring from an estimate of 14 to 17 million cu m/d to less than 1.5 million cu m/d.[88] Reinjection volume could be further expanded to cope with increased associated gas flowing from higher extraction rates.

To increase domestic consumption, $1.1 billion was spent on the national distribution grid — primarily to bring gas from fields in the south to the industrial area near San Fernando and Monterrey in the North. Apart from power generation, the two main industrial consumers of gas from the grid are the petrochemicals and steel sectors.

The context in which gas is used for petrochemicals is a $3 billion investment programme involving construction of 70 plants in period 1977 - 1982. The aim is to make Mexico self-sufficient in petrochemicals by 1980 and dispose of a 20 per cent surplus by 1982. Responsibility for the programme rests with the state oil agency, Petroleos de Mexicanos (Pemex) which is required to operate monopoly rights for some 45 basic petrochemicals - defined to include several polymers as well as monomers - and maintain at least a 60 per cent stake in projects in the secondary petrochemicals sectors.

Mexico's petrochemicals plants are mainly built at two complexes in the south-east: Cagrajera and Moratos. An entirely new complex is planned in Laguna de Ostion near Villa Hermosa in Tabasco province. Each will contain a 500,000 t/a ethylene cracker. In addition sites at Pajaritos, a Casoleacaque and Texmelucan are being expanded.

---

[88] Petroleum Economist, March 1979

By 1982 Mexico will have an installed capacity of 4.1 million t/a of ammonia, and 2.1 million t/a ethylene together with additional 1.5 t/a methanol capacity. Due on stream in the mid 1980s, the consumption of these large gas users will exceed 27 million cu m/d. Downstream and related petrochemicals units are to produce aromatics, low-and high-density polyethylene, styrene, VCM, acetaldehyde, ethylene oxide and acetonitrile.

For steel production, Mexico had developed its own direct reduction, process to convert iron ore to sponge iron. Known as the Hvl process,[89] the system consumes around 300 cu m/t iron. Mexico's planned capacity of 4.54 million t/a by 1985 will therefore be used 4.5 million cu m/d.

Overall assessment

Given the strenuous efforts being made to utilize associated gas, Mexico's problems with flared gas are simply that investment cannot keep pace with expanding oil production rate. Facing a choice between a cutback which would bring inflation under control and further expansion to cope with unemployment problems, the Government has chosen a growth strategy.[90] Where originally only 2.2 million b/d were planned by end 1980, remaining at that level for two years, mid 1980 already saw 2.7 million b/d and it could exceed 4 million b/d by 1982.

The extra revenue will pay for Mexico's industrial build-up but it will also nearly double the quantity of associated gas available. To avoid flaring, Mexico will either require additional exports to the United States or additional investment in NGL recovery, re-injection and general distribution facilities. Given acceptable gas prices, direct export to the United States could be stepped up to 22 million cu m/d with the addition of new compressor stations and pipelines.

89/ Developed by Hojalatay Lamina, Mexico City

90/ Business Week, 7 July 1980, P. 83

A $500 million fertilizer complex at Port Harcourt will include a 1,000 t/d ammonia unit, a 1,500 t/d urea plant and a 1,000 t/d NPK unit. Two United States companies, Transcontinental Fertilizer and International Minerals and Chemical Corp. have set up a joint partnership to help with operating management and take an equity stake in the complex. Some 40 to 50 per cent of output will be exported, mainly to Brazil and other South American markets.

Chiyoda of Japan is building a $37.5 million LPG unit with an output of 184,000 t/a. Completion at Lagos is due in October 1981. With only a small proportion going to bottle gas for local use, the output is mostly destined for export.

The Government has approved construction of a $10 billion LNG plant at Bonny Island with capacity building up in stages to a total of 16 billion cu m/a. The plant could utilize all of Nigeria's present flared assocated gas at full capacity, but in practice it must rely on non-associated gas supplies as well. Plans are to export half the LNG to eight customers in Western Europe and the other half to the United States. European customers are prepared to take all the gas if sales to the United States are not approved by the Government. Price negotiations are reportedly in the region of $5.50 to $6.00 c.i.f.[91]

Overall assessment

The government's intention to eliminate flaring by 1984 will be realized if re-injection, further gasification of the economy, e.g. substitution of fuel oil with associated gas, or use of associated gas as part of the raw material for the forthcoming Bonny LNG plant, add an additional load of around 5 million cu m/day. If restrictions on oil extraction rates are maintained, further gas-based industrialization would necessarily use non-associated gas.

---

[91] World Gas Report, 10 March 1980

NIGERIA

In 1978, associated gas accounted for all of Nigeria's natural gas output and 98 per cent, over 56 million cu m/d, was flared. Future production will be linked to oil production levels which are scheduled to peak at around 2.5 million b/d in 1981-1982. Under the five year plan starting in 1981 production of non-associated gas will also become significant.

Close government interest in the oil and gas industry's performance is reflected in the 1977 merger of the Nigerian National Oil Corp. and itw own Ministry of Petroleum Resources to form NNPC, the Nigerian National Petroleum Corp. Restructuring plans for the NNPC include setting up petrochemicals, gas production (including liquefaction) and marine transportation as separate divisions. NNPC will continue overall responsibility for exploration, marketing, processing and research, but all policy decisions on contracts, pricing and production will be taken by the Government. On pricing, however, Nigeria has said it will follow market trends

The Government's long term strategy includes pushing ahead with the Bonny LNG plant (see below) to provide export revenue that will enable it to conserve oil resources without restricting earnings. The next five year plan is also expected to include a petrochemical complex, part of which could be gas-based.

The major end uses of natural gas at present are desalination and power generations. Government plans were to use about 15 per cent of the associated gas for electricity generation by the end of 1980 and about 30 per cent by 1985.[92]

Significant amounts of gas are already utilized as fuel for the cement and glass industries. Plans are to expand the use of gas in these industries and start production of fertilizers, petrochemicals and steel, using natural gas by 1985.

---

[92] UNIDO/ICIS. 73

OMAN

Oman has only a relatively small gas output but its flaring rate is high. In 1978, when oil production reached 320,000 b/d, associated gas output was nearly 8 million cu m/d and all but 1.1 million cu m were flared.

Government utilization plans center on three gas separation plants and a distribution grid that will bring gas to the industrial area near Muscat. The separation plants at Soil Rol (in operation), Yibel and Fabud (under construction) will process up to 3.7 million cu m/d to yield nearly 8,000 b/d of gas liquids. The residual gas will pass by pipeline to the coast to fuel existing power station and desalination units. At a later stage it is intended to liquefy propane for household use at this plant.

The gas distribution line, completed in 1978, at present carries non-associated gas to replace imported refined products in industrial uses. This will be replaced in turn by residual associated gas when the gas separation plants (see above) come on stream.

Although plans call for substituting gas for refined products at other power stations in Oman, the only new major industrial projects on the way are 50,000 b/d refinery to be built at Miria Fahel and a Kuwait-Oman joint venture cement plant with a capacity of 600,000 t/a.

Overall assessment

Existing plans for gas separation indicate that at present oil extraction rates, flaring should drop to around 50 per cent by 1982-83.

This would leave ample margin for one or two ammonia or methanol units. With proven oil resources still rising, however, there is a possibility that extraction rates will increase during the 1980s, opening further opportunities for large scale industrial uses of associated gas.

QATAR

Gas has been used industrially in Qatar, initially for power generation, since the early 1960s. Production levels for associated gas in 1978 were nearly 13 million cu m/day, relating to a crude oil output of 490,000 b/d. An additional 5.9 million cu m/day were taken as non-associated gas. In relation to the associated gas 9 million cu m/day are flared, i.e. 71 per cent. There is a substantial improvement evident in data reported for 1979 and further improvements are due in 1981.

Since 1975, the Qatar Government has been using oil revenues to finance heavy industry developments. The aim is to build up a gas-based industry to replace oil revenues when they begin to decline in the late 1980s. As in Saudi Arabia, Qatar gains access to technology and markets by means of joint ventures with industrialized country partners. Most projects are realized in conjunction with the Qatar General Petroleum Corp. in Doha. Their prior conception and execution are in the hands of the Qatar Industrial Development Centre.

Because associated gas quantities are limited by oil extraction rates, the Government recognizes the need to develop non-associated gas supplies. Its dilemma is that the cost will be high——estimated $4 billion for the gas field alone. This means long term contractual arrangements are needed to guarantee investment returns. For this reason, Qatar has been one of the most active in promoting an OPEC price for gas at a level approaching parity with crude oil.

Gas utilization begins at the country's treating and fractionating units at Fahahil, operated by Qatar Gas Co. a joint venture between Qatar General Petroleum Corp and Shell Qatar. At full capacity this equipment will supply methane-rich streams totalling 6.42 million cu m/day, leaving 1.75 million t/a NGL for separation into LPG and around 1.2 million cu m/day of ethane—more than enough for existing and planned petrochemical use.

Another NGL unit comes on stream in 1981. Together they will deliver 550,000 t/a propane, 400,000 t/a butane and 360.000 t/a natural gasoline.

Residual gas from the two NGL plants will be used as fuel for cement (QNCC - Qatar National Cement Co.), petrochemicals (QAPCO - Qatar Petrochemical Co.), fertilizer (QAFCO - Qatar Fertilizer Co.), and the Dukhan power station. In addition to fuel, QAPCO also receives the two ethane-rich streams as feedstock for its new 280,000 t/a ethylene cracker and downstream low- and high-density polyethylene units. Other state power plants, desalination units, and the direct reduction sponge iron plant (QASCO - Qatar Steel Co.) will rely mainly on supplies of non-associated gas, but associated gas will be substituted where possible as a conservative measure.

Power, cement and desalination excluded, nearly all the large scale industrial utilization has been achieved in joint venture operations:

Joint venture	Partners
QAPCO	Cdf Chimie (16%), Qatar General Petroleum Co. (84%)[93]
QAFCO	Norsk Hydro (20%), Qatar General Petroleum Co. (80%)
QASCO	Kobe Steel (20%), Qatar General Petroleum Co. (80%)

In each case the foreign partner provides management services and or marketing expertise.

Overall assessment

With both NGL units in operation, combined gas consumption of 16.4 million cu m/d will permit a reduction of flaring to a practicable minimum. Nevertheless, gas throughput will still not cover demand from existing users of methane-rich streams for feedstock and fuel. Increasing supplements will therefore be required in the form of non-associated gas.

There is a contrasting situation in ethane, apparently. Ethane-rich gas will be available in quantities up to 1.2 million cu m/day—nearly twice the demand by QAPCO for its petrochemical complex.

93/ Qatar General Petroleum and CdF Chimie are also partners in a French petrochemical unit making 225,000 t/a ethylene at Dunkirk.

SAUDI ARABIA

In 1978 Saudi Arabia produced nearly 120 million cu m/d of associated gas in conjunction with a crude oil output averaging 8.3 million b/d. Current investments[94] once aimed at raising crude oil production to 12 million b/d, would yield an estimated 170 million cu m/day. To date there has been no exploitation of the country's non-associated gas resources but plans call for utilization to begin in 1982 when associated gas usage reaches 85 per cent of production. In 1978 only around 26 per cent of Saudi Arabia's associated gas found useful application. This included the 3 per cent used for re-injection. The remaining 74 per cent was flared.

Under Saudi Arabia's third five-year plan (1980-85) the emphasis has shifted from large-scale industrial projects to social and educational development. While no known petrochemical project has been affected, one result is a reduction of the planned gas collection and treating facilities. One NGL centre, at Khurais, has been cancelled and another at Safaniya, has been deferred. This indicates that for the forseeable future, gas treating capacity will be maintained at 113 million cu m/day instead of 170 million cu m/day as once envisaged. The Government's long-term goal remains, however, industrialization in a form that will provide Saudi Arabia with a substitute for oil revenues when they begin to decline in the late 1990s. In practical terms this is taken to mean petrochemicals, fertilizers and refined oil products rather than LNG.

The means [illegible] industrialization are various long-term co-operation arrangements with oil, chemical and industrial groups from industrialized countries. Government policy places strong emphasis on joint ventures as a way of ensuring that the products of industrialization reach the market place.[95]

---

[94] The Economist, 26 April, 1980 p. 56.

[95] In line with this, Petromin, Saudi Arabia's state oil company is both increasing its share of oil output and diversifying crude oil sales away from the Aramco companies. Direct sales to Governments and oil companies willing either to invest in petrochemical joint ventures or to process Saudi oil in their own refineries to provide Saudi Arabia with refined oil products or equivalent cash value can be expected to increase (see Mid East Markets, 1980). In 1979, petromin also announced (Mid East Markets, May 5, 1980) a cut of 25 per cent in LPG sales to Aramco— also with a view to increased direct sales.

It also ensures transfer of the best available technology and that the production plant is properly operated after being handed over by the contractor.

Recognizing too that many potential partners would prefer Saudi Arabia's energy to its manufactured products, the Government also operates a four-point incentive policy. This offers low-cost loan capital, large-scale infrastructural support, energy and feedstocks at favourable prices and additional oil or petrochemical feedstocks for the joint venture partner's use elsewhere.[96] In a typical petrochemical project, 60 per cent of the project capital may be provided at down to 3 per cent interest, 10 per cent would be borrowed at commercial bank rates, and joint ventures partners would divide the remainder (15 per cent each) as equity capital. Associated gas is initially made available at a starting price of 40¢/million Btu but rising under a complex escalation formula in line with net profits.[97] Power would be offered at the prevailing grid price of 4 mills/kWh. Crude oil entitlements could be negotiated up to 50,000 b/d per $1 billion invested.[98]

In 1975 a mammoth gas-gathering and processing programme was launched by Aramco,[99] a partnership of four United States oil majors set up to extract Saudi oil. When completed in 1982 the projects will process a total of 113 million cu m/day. Facilities for collecting, processing and treating 26 million cu m/day are already in operation at Berri, Abqiq, Ras Tannura, Abu Ali and Jubail.

A further 85 million cu m/day of gas will be processed in two of the world's largest NGL plants, now being completed at Shedgum and Uthmaniyah in the Ghawar oil fields. Residue gas, around 29 million cu m/day and mainly of methane, is to be piped to an industrial complex at Jubail (see below) for use as fuel and feedstock. The NGL streams are fed, also by pipeline, to fractionating units at Ju'aymah and Yanbu. In addition to propane, butane

---

[96] Oil and Gas Journal, July 9, 1979

[97] The Aramco gas gathering system is reportedly supplying ethane to the Jubail and Yanbu complexes at around 56¢/1000 cu ft, i.e. about one fifth of prevailing world prices—Mid East Markets, August 11, 1980, P.14

[98] Shell Oil (United States) reportedly receives 200,000 b/d in connexion with its participation in the $3 billion ethylene joint venture at Jubail (Mid East Markets, ibid).

[99] Revised rates relfecting larger than expected Saudi oil commitments to Aramco companies and increased investment costs for the project.

and natural gasoline, the Ju'aymah fractionator produces 5.52 million cu m/day of ethane destined for petrochemical use at Jubail. Some 4.9 million cu m/day of ethane will be available from the Yanbu' fractionator and is earmarked for use at the nearby petrochemical complex.

Responsibility for industrial utilization of associated gas is vested in Sabic, the Saudi Arabia Basic Industries Corp., which is also the joint venture partner for international investors. Two industrial sites are being developed on the basis of piped supplies of methane and ethane available from the new fractionators, one at Jubail the other at Yanbu'. Total investment in petrochemicals alone will be at least $10.5 billion.[100]

When Saudi Arabia's gas collection, processing and treating facilities are completed in 1983, around 40 per cent of the available associated gas will be able to be exported as either LPG or condensates. The existing plant produces 200,000 b/d (9.5 million t/a—3.5 million t/a propane, and 3 million t/a each of butane and natural gasoline.) The two new NGL units at Ju'aymah and Yanbu' will add 190,000 b/d propane, 143,000 b/d butane and 38,000 b/d natural gasoline.

The key investments are four or five ethane-based ethylene crackers—up to four at Jubail, one at Yanbu'. At Jubail a commitment-in-principal agreement for a 656,000 t/a cracker for Saudi Pecten, a joint venture between Sabic and Pecten Arabia (a subsidiary of Shell Oil in the United States) was signed in September 1980. Downstream units are to produce styrene, ethylene dichloride, ethanol and chlorine/caustic soda. Waiting final approval, a Sabic-Dow Chemical joint venture plans to make 500,000 t/a ethylene to supply units for low-and high-density polyethylene and ethylene glycol. Another low-density polyethylene plant has been agreed for SABIC-Exxon. Saudi-Pecten will supply the ethylene. The fourth possible cracker at Jubail is a SABIC-Saudi Petrochemical Development Co. joint venture. Led by Mitsubishi Gas Chemical, Saudi Petrochemical is consortium of Japanese companies and the Japanese government. Planned ethylene capacity is 450,000 t/a to feed downstream units making low- and high-density polyethylene, and ethylene glycol. The cracker at Yanbu', to be operated by a Sabic) Mobil Oil joint venture, is also 450,000 t/a and has the same product line up.

---

[100] *Mid East Markets*, May 19, 1980

All the Saudi Arabian methane-based joint ventures are to be located at Jubail. Two 2,000 t/d methanol plants are assigned to the Saudi-Japanese Methanol Co. (agreed November 1979) and a Sabic-Celanese-Texas Eastern joint venture (awaiting final approval). At least 100,000 t/a from the Japanese plant will be consumed domestically, the remainder will replace butane-based production in Japan. The Al-Jubail Fertilizer Co., a joint venture between Sabic and Taiwan Fertilizer Co., is building a 1000 t/d ammonia plant and a 1600 t/d urea unit. Nearly all the urea will be exported to Taiwan and other markets.

The other large industrial users of methane are Saudi Arabia's power, desalination, steel and cement industries. During the third five-year plan the Government is spending $3.75 billion to triple its existing 3,000 MW generating capacity; the long-term goal is 29,000 MW. Desalination projects, the responsibility of SWCC, the Saline Water Conversion Corp., include a 200 million gal/day unit at Jubail (Jubail II) and another large unit at Al-Khobar (Al-Khobar II). The Saudi Iron and Steel Co., a joint venture between SABIC and Korf Stahl in the Federal Republic of Germany, is building an 800,000 t/a direct reduction sponge iron plant at Jubail to supply steel billets to rolling mills at Jubail and Jeddah. Cement, like steel presently imported in large quantities, will be increased from 12.5 to 10 million t/a.

Overall assessment

At current oil production levels, gas utilization in 1985 should at least reach the 85 per cent target set by the authorities. This would call for an increase in re-injection to 21 million cu m/day leaving 113 million for separation and fractionation. Most of the fractionator output is to be accounted for by LPG and natural gasoline sales. Known petrochemical, steel and cement uses add up to nearly 16 million cu m/day leaving 22 million for other industrial and domestic uses. This difference can be more than accounted for by power generation alone if all power stations are switched to run on sweet gas from the fractionators.

SYRIA

In 1978 Syria produced an estimated 4.4 million cu m/d of associated gas in conjunction with an oil output of 175,000 b/d. Of this 1.4 million cu m/d were flared. In the previous years an attempt was made to use this gas as a fuel for oil field pumping stations and power generation. Although this temporarily cut flaring to zero, the scaling problems that resulted meant it had to be resumed at a level of 100 per cent in the following years.

In view of the small quantities of associated gas available, Government strategy centers on construction of a gas gathering and treating system. The Syrian Petroleum Co. (SPC) is building a $63 million plant at Suwaidiyah to handle 0.8 million cu m/day producing up to 55,000 t/a of LPG and 50,000 t/a natural gasoline. Residual gas output will be 0.7 million cu m/day.

In addition to power generation and oil field operations, surplus gas from the treating plant may also be used by Syria's cement industry. Present capacity is 2.5 million t/a, and four new units under construction will bring this to 6 million t/a.

The main new industrial use forseen for natural gas is 1 million t/a sponge iron plant being considered by Syria General Organization of Engineering Industries.

(Syria also has a fledgling petrochemical industry but it is entirely naphtha-based. Given the limited availability of associated gas and Syria's relatively large refinery capacity—11 million t/a i.e. higher than oil output—naphtha will probably remain the preferred feedstock.)

Overall assessment

Although oil exploration is continuing, the anticipated falling oil production rate will mean reduced output of associated gas in coming years. From 1.26 million cu m/day in 1980, production will decline to around 1 million in 1985, 0.7 million in 1990 and 0.6 million in 1995. Re-injection is scheduled to begin in 1985. In conjunction with extraction and industrial uses, this will enable flaring to be reduced to 0.1 million cu m/day, i.e. 13 per cent production.

Given this scenario, the present policy of developing thermal uses for associated gas, which could be substituted by non-associated gas when supplies run low, seems to have no alternative.

TRINIDAD AND TOBAGO

In 1978, Trinidad's output of associated gas was 11.3 million cu m/d in conjunction with 240,000 b/d of crude oil. Of this 4.9 million cu m was used industrially, the remaining 62 per cent being flared. Re-injection which in 1970 accounted for 15 per cent of gas utilization (1.5 million cu m/d) had declined to nearly zero as production in older fields fell off. In addition to associated gas there are estimated reserves of 240,000 million cu m of non-associated gas. In 1980 this was being extracted at the rate of 4.8 million cu m/d.

Government strategy for exploiting natural resources recognizes the declining level of oil production. By the year 2000 this will be negligible and gas as designated as a replacement revenue source. Attention is therefore focused on direct export (LNG), methane-based petrochemicals and energy intensive allications. Most projects are handled on the basis of joint ventures in which the Government is the major shareholder.

The LNG project, sited at Point Lisas with a capacity of nearly 20 million cu m/d, is a joint venture between the Government (51 per cent), Tenneco (24.5 per cent) and People's Gas of Chicago (24.5 per cent). The output is intended for the US market, possibly entering via Canada.[101] Plant delivery is scheduled for 1983 and the unit is designed to operate on both associated and non-asociated feedstock. A similar sized project with Occidental Petroleum has apparently been dropped.

101/ World Gas Report, 13 Nov. 1979

Petrochemical uses for associated gas are presently represented by two ammonia units operated as a joint venture by the Trinidad Nitrogen Co. and W. G. Grace. The capacity is 705,000 t/a requiring around 1.3 million cu m/d of gas. Two further units, being built as a joint venture between Fertrin and Amoco will bring capacity up to 2.5 million t/a in 1985. The Fetrin/Amoco project will also include 530,000 t/a urea unit.

Another unit under study is a 330,000 t/a methanol plant, also projected for Point Lisas. This would be in conjunction with the Borden Chemical Co. and is due in stream in 1982.

In metals the Iron and Steel Company of Trinidad and Tabago expects to start up a 550,000 t/a spongeiron and steel plant in 1981. Direct reduction of imported ore will be used to produce sponge iron; an associated rolling mill will produce steel wire, rods and profiles for export to Carricom market and the United States. Gas consumption will be approximately 1 million cu m/d. The plant is at present fully state owned, although equity participation by others is possible later. Korf-Stahl AG of West Germany has a contract for management responsibility and training for the first five years.

The Government is also planning a 180,000 t/a aluminium smelter to start up in 1983. Gas consumption would be in a region of 1.1 million cu m/d. The other large energy user is Trinidad's cement industry currently producing 250,000 t/a; this will be expanded by 300,000 t/a in 1981.

Overall assessment

Total gas consumption for present industrial and oil field uses (1980) is 9.4 million cu m/d. Flaring rate has dropped to 4.2 million cu m/d i.e. 31 per cent of all gas produced, but 48 per cent of the associated gas portion. Improvements are in the pipeline but mostly in the direction of using new sources of non-associated gas. By 1985 industrial use will have reached 34.3 million cu m/d. Flaring will have dropped to 2.8 million, 7.5 per cent of total gas production but still 38 per cent of associated gas output. Given the low ethane content of Trinidad's associated gas (4 per cent), any potential ethylene complex will best be based on refinery feedstock, of which Trinidad will continue to have a large surplus.

UNITED ARAB EMIRATES

In 1978 the Emirates produced 37.1 million cu m/d of natural gas, all associated with 1.8 million b/d of crude oil. Of this 29.5 million cu m/d arose in Abu Dhabi, the remaining 7.6 million in Dubai. Overall flaring rate at the time was 62 per cent and there was no re-injection.

The Emirates' strategy for gas utilization reflects the view that with a small population and an already established basic infrastructure, there is no need to increase revenues by expanding output. In line with this, investment policy aims to use gas that would otherwise be flared, leaving non-associated gas in the ground as long as possible. The core of this is Abu Dhabi National Oil's (ADNOC) gas gathering programme, the Abu Dhabi Gas Liquefaction's LNG plant at Das Island, and Dubai's $400 million LPG unit at Jabel Ali.

Abu Dhabi Gas Liquefaction is a joint venture between ADNOC (15 per cent), the Mitsui group, BP, CFP, and Bridgestone Liquid Gas. Its $600 million LNG plant will have a full design capacity of 2.3 million t/a of LNG and 1.3 million t/a LPG—all to be shipped to Japan under a twenty year contract. Abu Dhabi has reportedly been successful[102/] in linking its gas prices to those of oil. In May 1980 they reached $5.75/million Btu. The plant will consume 15.6 million cu m/d gas - mostly associated gas but supplemented where necessary by non-associated sources.

A still larger complex is now being commissioned by Abu Dhabi Gas Industries to handle 29.6 million cu m/d of associated gas from offshore fields at Hasa, Asab, Bab and Sahil. A joint venture between ADNOC (68 per cent), CFP and Shell (15 per cent each) and Partex (2 per cent), the NGL plant at Ruwais will cost $1.8 billion and produce

---

[102/] Financial Times, 31 June 1980

5 million t/a of LPG and condensates. The product will be shipped under long term contract to Japan; residual gas as slated for eventual use in fertilizer (see below).

In Dubai, planned gas gathering operations are more modest in line with the smaller oil output (361,000 b/d) and its predicted decline. Dubai National Gas (Dugas), a joint venture between the Dubai Government (80 per cent) and Scimitar Oils, (20 per cent) is building a 300,000 t/a LPG plant. Gas consumption will be 4 million cu m/d. LPG together with 150,000 t/a of gas liquids will be exported to Japan; and 75 per cent of the residual gas and will be used by Dubal to make aluminium (see below).

At present there are no petrochemical facilities in the Emirates but lean gas from the Ruwais NGL plant is to be used in a 1000 t/d ammonia plant and an associated 1500 b/d urea unit. A second 1000 t/d ammonia plant will be added later.

Apart from power generation and oil refinery use, the only large industrial gas users in the Emirates are the cement industry, with plants at Dubai, Shargha and Fujeirah and the aluminium industry.

Dubai's aluminium producer, Dubal, was originally a joint venture with British and United States partners. It was to become fully state-owned by the end of 1980 as part of rearrangements giving the Government full control over marketing the plant's 135,000 t/a design output. To this end the Dubai Aluminium Authority has been established with membership including Pakistani, British and United States representatives.103/ Future sales will be handled by Gulf Resources Corp, which is expected to resell mostly via the spot market.

Overall assessment

Although flaring levels have been high, projects now in hand together with restrictions on oil output will turn the Emirates into gas-short area. The gas processing plants at full capacity will consume 49 million cu m/d when their collection systems reach equal capacity. A project to increase

---

103/ Mid East Markets, 10 March 1980

collection at Upper Zakum will eliminate the need to use non-associated supplies for the Das Island LNG plant and provide a 22 million t/a surplus for re-injection.

When the Ruwais extraction plants come on stream in 1981 there may be a temporary surplus of lean gas until the fertilizer complex is ready. Thereafter anticipated demand from all industrial uses (power generation, desalination, fertilizer and utilities) is estimated at 12.1 million cu m/d and the supply will have to be supplemented from a non-associated source.

In Dubai, Dugas is already looking for additional gas source in the neighboring Emirates and Oman.

In summary the Emirates flaring problem will soon be a thing of the past. Future industrialization would have to proceed on the basis of non-associated gas. In this connexion projects under study include a second LNG plant, a petrochemical industry and a sponge iron plant.

VENEZUELA

With only 7.9 million cu m/d (7 per cent) of 1978 production being flared, Venezuela can be said to have already solved the flaring problem. Associated gas production in that year was 94.6 million cu m/d; of this 47.4 million cu m/d were re-injected and 35.2 million cu m/d used by industry.

Government policy on natural gas is determined mainly by a 1971 law reserving exploitation to Corpoven, a subsidiary of Petroleos de Venezuela (Petroven), the state oil company. The law also says that only associated gas can be exploited. In practice gas usage forms an integral part of Government strategy to build up large-scale resource-based industries— in particular, chemicals and steel.

Gas-based petrochemicals are produced by another Petroven subsidiary, Petroquimica de Venezuela (Pequiven). Its main complex, at El Tablazo in Zulia, has plants for ammonia, urea, polystyrene, ethylene and polypropylene. VCM and PVC plants are currently being commissioned and a joint venture high density polyethylene unit is due on stream for 1982. Foreign participation in this unit includes CdF Chimie and the Mitsui group. At Morón, Pequiven operates a second ammonia plant, a chlorine/caustic unit and a sulphuric acid plant. A further four complexes are planned costing 32.3 billion, the first at Puerto dela Cruz.

As part of a national steel target of 15 million t/a in the year 2000, Venezuela's Corporacion Venezolana de Guayana (CVG) is building up production in the Orinoco region. In 1980 CVG's subsidiary Siderurgica de Orinoco (Sider) commissioned three 400,000 t/a direct reduction sponge iron plants.

Overall assessment

The future for associated gas utilization in Venezuela depends on the development of the country's different crude oils. Both the density and volume are at present uncertain. Low flaring levels presently reflect very high re-injection rate. But as the older wells finally run out, re-injection requirements may fall, leaving more gas for industrial use. In the long run, availability will be determined by the ratio of light and heavy crudes in Venezuela oil output.

Given the aggressive industrialization strategy and the demand for gas it is doubtful if flaring will ever resume in large quantities.

ANNEX III

Petrochemical demand and supply, 1975 to 1990

1. **Ethylene**
2. **Low-density polyethylene**
3. **High-density polyethylene**
4. **Polyvinyl chloride**
5. **Ethylene oxide/glycol**

Table III.1

World capacity, production and demand for ethylene

Region	Capacity			Production			Demand					
	1975	1979	1984	1975	1979	1984	1975	1979	1984		1990	
	1000 t/a	1000 t/a	1000 t/a	1000 t/a	1000 t/a	1000 t/a	1000 t/a	1000 t/a	1000 t/a	growth rate %	1000 t/a	growth rate %
North America	13 324	18 346	21 546	9 827	14 300	18 390	9 830	14 335	18 590	5.3	23 520	4.0
Western Europe	12 503[a]	14 709[a]	17 600[a]	7 910	12 358	14 100	7 888	12 211	13 900	2.6	17 580	4.0
Eastern Europe	2 752	3 932	5 632	2 064	3 038	4 560	2 064	3 038	4 420	7.8	6 480	6.6
Other developed countries	5 564	6 604	7 099	3 673	5 266	6 010	3 673	5 266	6 010	2.7	7 300	3.3
Total developed countries	34 143	43 591	51 877	23 474	34 962	43 060	23 455	34 850	42 920		54 880	
Africa	-	-	-	-	-	-	-	-	-		200	
Middle East	55	230	1 140	39	80	490	39	75	490	45.5	2 300	29.4
Asia	563	978	1 628	399	880	1 465	399	880	1 595	12.6	3 140	12.0
Latin America	868	1 586	3 306	562	950	1 940	562	950	1 940	15.4	3 600	10.9
Centrally planned Asia	65	586	1 301	65	445	820	65	445	820	13.0	1 750	13.5
Total developing countries	1 551	3 380	7 375	1 065	2 355	4 715	1 065	2 350	4 845		10 990	
World total	35 694	46 971	59 252	24 539	37 317	47 775	24 520	37 200	47 765		65 870	
Share of developing countries in world total (%)	4.3	7.2	12.4	4.3	6.3	9.9	4.3	6.3	10.1		16.7	

Source: UNIDO, compiled from Petrochemical Industry Associations, government statistics, and other published material.

a/ CEFIC figures are for effective capacity, not nominal capacity.

b/ Based on committed/announced downstream capacities in the developing countries up to 1990.

Table III.2

World capacity, production and demand for low-density polyethylene

Region	Capacity			Production			Demand					
	1975	1979	1984	1975	1979	1984	1975	1979	1984		1990	
	1000 t/a	1000 t/a	1000 t/a	1000 t/a	1000 t/a	1000 t/a	1000 t/a	1000 t/a	1000 t/a	growth rate %	1000 t/a	growth rate %
North America	3 211	4 193	6 185	2 421	3 926	5 139	2 306	3 454	4 400	5.0	5 560	4.0
Western Europe	4 550	5 625	6 500	3 285	4 580	4 900	2 600	4 000	4 500	2.4	5 690	4.0
Eastern Europe	800	1 385	2 150	600	1 130	1 760	700	1 130	1 660	8.0	2 490	7.0
Other developed countries	1 530	1 770	1 930	1 070	1 518	1 530	973	1 357	1 360	0.0	1 620	3.0
Total developed countries	10 091	12 970	16 765	7 376	11 094	13 329	6 579	9 941	11 920		15 360	
Africa	-	-	-	-	-	-	95	150	240	10.0	445	11.0
Middle East	27	75	365	25	25	290	190	320	560	12.0	1 100	12.0
Asia	120	375	820	108	300	735	410	690	1 210	12.0	2 150	10.0
Latin America	390	540	1 090	340	450	930	470	735	1 180	10.0	2 090	10.0
Centrally planned Asia	34	300	420	25	265	370	68	300	440	8.0	740	9.0
Total developing countries	571	1 290	2 695	498	1 040	2 325	1 233	2 195	3 630		6 525	
World total	10 662	14 260	19 460	7 874	12 134	15 654	7 812	12 136	15 550		21 885	
Share of developing countries in world total (%)	5.4			6.3	8.6	14.9	15.8	18.1	23.3		29.8	

Source: UNIDO, compiled from Petrochemical Industry Associations, government statistics, and other published material.

Table III.3

World capacity, production and demand for high-density polyethylene

Region	Capacity			Production			Demand					
	1975	1979	1984	1975	1979	1984	1975	1979	1984		1990	
	1000 t/a	1000 t/a	1000 t/a	1000 t/a	1000 t/a	1000 t/a	1000 t/a	1000 t/a	1000 t/a	growth rate %	1000 t/a	growth rate %
North America	1 675	2 735	4 355	1 257	2 559	3 175	1 186	2 260	2 910	5.2	3 685	4.0
Western Europe	1 720	2 360	2 670	1 200	1 770	2 000	900	1 520	1 850	4.0	2 340	4.0
Eastern Europe	180	360	930	127	280	760	143	314	710	17.7	1 130	8.0
Other developed countries	955	1 020	1 090	409	895	990	364	773	870	2.4	1 030	3.0
Total developed countries	4 530	6 475	9 045	2 993	5 504	6 925	2 593	4 867	6 340		8 185	
Africa	--	--	--	--	--	--	30	54	95	12.0	165	10.0
Middle East	--	--	40	--	--	30	38	75	135	12.0	250	11.0
Asia	90	150	375	70	109	300	137	265	490	13.0	915	11.0
Latin America	30	190	420	25	120	340	135	243	430	12.0	760	10.0
Centrally planned Asia	--	--	140	--	--	115	15	40	115	23.5	250	13.8
Total developing countries	120	340	975	95	229	785	355	677	1 265		2 340	
World total	4 650	6 815	10 020	3 088	5 733	7 710	2 948	5 544	7 605		10 525	
Share of developing countries in world total (%)	2.6	5.0	9.7	3.1	4.0	10.2	12.0	12.2	16.6		22.2	

Source: UNIDO, compiled from Petrochemical Industry Associations, government statistics, and other published material.

Table III.4

World capacity, production and demand for polyvinyl chloride

Region	Capacity			Production			Demand					
	1975	1979	1984	1975	1979	1984	1975	1979	1984		1990	
	1000 t/a	1000 t/a	1000 t/a	1000 t/a	1000 t/a	1000 t/a	1000 t/a	1000 t/a	1000 t/a	growth rate %	1000 t/a	growth rate %
North America	2 643	3 633	4 856	1 791	2 973	4 050	1 807	3 001	4 060	6.2	5 140	4.0
Western Europe	4 550	5 300	5 800	3 400	4 320	4 700	2 800	3 930	4 550	3.0	5 760	4.0
Eastern Europe	1 140	1 848	2 900	855	1 560	2 320	975	1 430	2 010	7.0	2 850	6.0
Other developed countries	2 105	2 479	2 480	1 225	1940	2 110	1 241	1 810	2 220	4.2	2 800	4.0
Total developed countries	10.438	13 260	16 036	7 271	10 793	13 180	6 823	10 171	12 840		16 550	
Africa	--	--	--	--	--	--	90	166	290	12.0	540	11.0
Middle East	52	112	272	23	75	210	140	215	360	11.0	640	10.0
Asia	385	886	1 290	325	726	1 100	360	830	1 460	12.0	2 590	10.0
Latin America	334	645	1 035	267	460	830	372	575	970	11.0	1 710	10.0
Centrally planned Asia	--	103	303	220 1/	357 1/	460 1/	259	430	630	8.0	1 050	9.0
Total developing countries	771	1 746	2 900	835	1 618	2 600	1 221	2 216	3 710		6 530	
World total	11 209	15 006	18 936	8 106	12 411	15 780	8 044	12 387	16 550		23 080	
Share of developing countries in world total (%)	6.9	11.6	15.3	10.3	13.0	16.5	15.1	17.9			28.3	

Source: UNIDO, compiled from Petrochemical Industry Associations, government statistics, and other published material.

Includes substantial PVC supplies from non-petrochemical sources.

Table III.5

World capacity and demand for ethylene oxide and ethylene glycol.

Region	Ethylene oxide				Ethylene glycol			
	Capacity		Demand		Capacity		Demand	
	1979 1000 t/a	1984 1000 t/a	1979 1000 t/a	1984 1000 t/a	1979 1000 t/a	1984 1000 t/a	1979 1000 t/a	1984 1000 t/a
North America	3 300	4 080	2 716	3 350	3 100	3 450	2 200	2 600
Western Europe	2 070	2 400	1 700	1 970	1 535	1 670	1 115	1 260
Eastern Europe	620	950	500	810	500	760	400	650
Other Developed Countries	695	780	593	665	650	725	595	670
Total Developed Countries	6 685	8 210	5 509	6 795	5 785	6 605	4 310	5 180
Africa	-	-	-	-	-	-	20	32
Middle East	-	55	-	47	-	70	52	76
Asia	232	312	182	255	290	390	240	400
Latin America	130	450	110	165	165	290	145	215
Centrally Planned Asia	48	48	39	40	60	60	70	95
Total Developing Countries	410	865	331	507	515	810	527	818
World total	7 095	9 075	5 840	7 302	6 300	7 415	4 837	5 998
Share of Developing Countries in World Total (%)	5.8	9.5	5.7	6.9	8.2	10.9	10.9	13.6

Source: UNIDO, based on published sources and polyester fiber forecasts.

ANNEX IV

New uses for methanol[104]

To a very large extent the future of methanol is concerned with potential fuel uses. These are particularly difficult to quantify. Among a number of forecasts quoting future consumption figures, SRI estimates total United States demand for fuel uses in 1983 to be about 550,000 t/a. A recent study by Snam Progetti envisages a 30 to 40 per cent penetration of the West European gasoline market by 1990 giving a methanol demand of over 25 million tons.

From this it may be deduced that a substantial use of methanol for fuel purposes will develop and that a number of very large plants will have to be built.

Fuel uses

MTBE (Methyl Tertiary Butyl Ether)

The production of MTBE as a gasoline blending component is already in progress in the United States and Europe.

With the phase out of tetra-ethyl lead in gasoline in both the United States and Europe, the possibility of using MTBE as an octane booster is extremely opportune. Its blending value in a gasoline pool is 109 and - because of its low carbon monoxide exhaust emission - it has been approved by the United States - EPA for use up to 7 per cent in unleaded gasoline pools.

The projected annual growth rate in the United States is 10 to 20 per cent annually through to 1983. By then total United States capacity will reach 1.33 million t/a; Europe will have 0.63 million and Japan 7,000 t/a.

---

[104] Condensed from GOIC study: "Methanol Marketing", GOIC, Doha, November 1980.

MTBE is produced from methanol and iso-butylene. The limited availability of the latter could pose problems for the oil-producing countries since unsaturated C_4s are not present in associated gas. This could be overcome with a butane dehydrogenation step.

Methanol - TBA (tertiary butyl alcohol) mixtures

Like MTBE, a TBA mixture is an octane improving agent for unleaded gasoline blends. It was introduced in the United States in 1979 by Oxirane under the trade name of Oxinol and its use is still at a relatively early stage of development. TBA availability in the United States by 1983 could permit up to 1.5 million tons of blending mixture. Whether this will happen depends largely on its acceptance by oil refiners.

Synthetic gasoline

Mobil Oil has developed a process for converting methanol to gasoline. Methanol is dehydrated to dimethyl ether and converted over a zeolite catalyst to gasoline type hydrocarbon components. The process gives a yield of 75 to 80 per cent gasoline per pass. Approximately 24 per cent is in the form of hydrocarbon gases that may be reconverted to make additional gasoline, thus giving an overall gasoline yield of about 88 per cent on methanol feedstock. The resulting gasoline contains 56 per cent paraffins, 33 per cent aromatics, 7 per cent olefins and 4 per cent naphthenes, i.e. the process could also be a useful source of aromatics.

The first commercial scale plant, in New Zealand, will produce 530,000 t/a of gasoline by the mid-1980s. Similar projects are under development in South Africa and the Federal Republic of Germany. It should be noted that this technology is equally applicable to gas or coal-based methanol; the latter was very much in mind at time of process development and could provide the major source in the long term.

Methanol as an automotive fuel

In addition to blends (see below), methanol can be used directly as an automotive fuel at 100 per cent concentration. Specially designed engines and carburation systems are required with low air/fuel ratios and high compression ratios. Two drawbacks are a 65 per cent larger volume of fuel compared to gasoline and the need for dual fuel systems making gasoline available for cold starting. Methanol has already been used successfully for racing cars where these considerations are not important.

Methanol in gasoline blends

The use of methanol in gasoline blends is under active consideration in the United States, Sweden, Norway, New Zealand and Australia.

The balance of advantages and disadvantages may be summarized as follows:

Advantages:

- high octane numb[illegible] blending at about 112;
- reduced nitrogen [illegible]des emissions;
- availability from [illegible]n-oil feedstocks.

Disadvantages:

- calorific value is only half of that of gasoline on a volume basis;
- generally higher cost than gasoline in unit energy terms; this will continue if the feedstocks used to produce it are linked in price to crude oil;
- a 15 per cent blend only reduces gasoline requirements by about 8 per cent; this would have an insignificant strategic impact;
- addition of methanol increases the blend vapour pressure disproportionately at concentrations up to 5 per cent; the concentration of low-cost butane must be reduced to compensate;
- gasoline volatility is increased and vapour lock temperature therefore decreased;
- cold starting is more difficult due to methanol's high latent heat;

- air/fuel ratios must be increased considerably requiring different carburettors for some cars;
- methanol corrodes many materials used in automobile fuel systems and swells plastic and rubber components; research in corrosion inhibitors is progressing, but some change in construction materials would probably be required;
- methanol is miscible with water, which means discontinuing the current practice of maintaining water seals in the bottom of gasoline tanks in filling stations as a precaution against leakage; methanol also absorbs water from the air, and this water separates out in the gasoline tank; this has not proved a problem in practice.

Most of these technical problems could be overcome at the automobile design stage, but it would be difficult to use methanol blends in existing cars without modification. Its introduction is therefore likely to be a gradual process.

Notwithstanding these problems a number of countries are planning to introduce methanol blends. Volkswagen estimates that the Federal Republic of Germany alone will require 3.5 million tons of methanol capacity for this purpose by 1992.

Power generation

Methanol has already been tested as a boiler fuel and in gas turbines. For both it is satisfactory; due to the reduction in pollution, it could be especially attractive at locations where pollution is a real problem. However until the very large methanol plants are built, methanol availability will not be sufficient to permit the development of this market.

Chemical Uses - Ethylene

Producing olefins from methanol is similar to the process developed by Mobil for making synthetic gasoline. Mobil has issued two patents relating to olefins production and BASF is reported to be building a large pilot plant.

A recent SRI study indicates an overall ethylene yield of 21 weight per cent on methanol. Compared to conventional gas oil cracking the economics do not look attractive: based on current cost projections, methanol would not become competitive with gas oil as an ethylene feedstock before the 1990s.

Food Uses - Petroprotein

Animal feed protein production from hydrocarbons has yet to achieve acceptance by both governments and the market. Adverse reactions in Italy, for example, prevented operation of completed plants, and in Japan all development work has ceased. BP, after many years of development based on gas oil and normal paraffins, has stopped production at its two semi-commercial plants - one in Scotland, one in France.

Work continues, however, in Eastern Europe, the USSR, the Federal Republic of Germany and the United Kingdom. ICI, for example, uses methanol feedstock in a 1,000 t/a pilot plant commissioned in 1973 and a full scale 50,000 to 70,000 t/a plant that started up in 1979. ICI's programme is favoured by relatively low cost gas from the North Sea.

Besides gaining public/governmental acceptance, petroprotein must also compete against soyabean meal and fish meal. These are predicted to be adequate to meet animal feed requirements until the 1990s. The world-wide market is of course enormous and sooner or later petroprotein or some other alternative will be required on a straightforward demand basis. Optimistic sources see a world-wide methanol demand for petroproteil reaching 2.5 to 5.0 million t/a in the late 1980s.

ANNEX V

Production cost breakdowns for petrochemicals, fertilizers, methanol, sponge iron, steel and aluminium

1. Ethylene
2. Ethylene oxide
3. Ethylene glycol
4. HDPE
5. LDPE
6. Methanol
7. Ammonia
8. Urea
9. Sponge iron
10. Steel
11. Aluminium

Table V.1

Investment and production costs for ethylene at four locations in 1980

Product: ethylene
Feedstock: ethane

Plant capacity[a]: 500,000 t/a
Daily throughput: 1500 t/d

Location	U.S. Gulf Coast	FRG	Arabian Gulf	Mexico
Location factor	1.0	1.15	1.3	1.25
Investment cost:	$ million	$ million	$ million	$ million
Battery limits	215.30	328.62[b]	279.89	269.12
Offsites	100.00	155.79	130.00	125.00
Total	315.30	484.41	409.89	394.12
Working capital	37.89	14.70	16.64	18.24
	$/ton	$/ton[b]	$/ton	$/ton
Feedstock cost	215.00	326.00[b]	25.00	56.52
Production cost:				
Variable cost	309.86[d]	434.57[f]	56.99[c]	89.94[e]
Fixed cost	112.61	192.36	126.70	120.90
Net production cost	422.47	626.93	183.69	210.84

[a] At 90% stream factor.
[b] Naphtha feedstock.
[c] Excludes by-product credit of $7.86.
[d] Excludes by-product credit of $61.98.
[e] Excludes by-product credit of $10.07.
[f] Excludes by-product credit of $625.69.

Table V.2

Investment and production costs for ethylene oxide at four locations in 1980

Product: ethylene oxide
Feedstock: ethylene

Plant capacity[a] 131,000 t/a
Daily throughput: 400 t/d

Location	U.S. Gulf Coast	FRG	Arabian Gulf	Mexico
Location factor	1.00	1.15	1.30	1.25
Investment cost:	$ million	$ million	$ million	$ million
Battery limits	81.76	94.01	106.29	102.20
Offsites	26.25	30.22	34.12	32.81
Total	108.01	124.23	140.41	135.01
Working capital	9.44	13.03	9.09	9.38
	$/ton	$/ton	$/ton	$/ton
Feedstock cost	423.00	627.00	184.00	210.00
Production cost:				
Variable cost	473.01	703.93	227.55	260.57
Fixed cost	152.82	188.52	189.97	175.64
Net production cost	625.83	892.45	417.52	436.21

[a] At 90% stream factor.

Table V.3

Investment and production costs for ethylene glycol at four locations in 1980

Product: ethylene glycol

Feedstock: ethylene oxide

Plant capacity[a]: 150,000 t/a

Daily throughput: 455 t/d

Location	U.S. Gulf Coast	FRG	Arabian Gulf	Mexico
Location factor	1.00	1.15	1.30	1.25
Investment cost:	$ million	$ million	$ million	$ million
Battery limits	18.16	20.93	23.60	22.70
Offsites	11.09	12.75	14.40	13.86
Total	29.25	33.68	38.00	36.56
Working capital	10.67	14.48	8.59	8.70
	$/ton	$/ton	$/ton	$/ton
Feedstock cost	626.00	892.00	418.00	436.00
Production cost:				
Variable cost	490.05[b]	698.26[c]	328.82[d]	342.93
Fixed cost	44.27	55.42	52.62	47.20
Net production cost	534.32	753.67	381.44	390.13[e]

a/ At 90% stream factor.
b/ Excludes by-product credit of $3.61.
c/ Excludes by-product credit of $3.54.
d/ Excludes by-product credit of $1.56.
e/ Excludes by-product credit of $2.08.

Table V.4

Investment and production for HDPE at four locations in 1980

Product: HDPE

Feedstock: Ethylene

Plant capacity[a]: 75,000 t/a

Daily throughput: 230 t/d

Location	U.S. Gulf Coast	FRG	Arabian Gulf	Mexico
Location factor	1.00	1.15	1.30	1.25
Investment cost:	$ million	$ million	$ million	$ million
Battery limits	23.19	26.64	30.14	28.98
Offsites	18.97	21.52	24.65	23.71
Total	42.16	48.16	54.79	52.69
Working capital	6.82	9.71	5.77	5.79
	$/ton	$/ton	$/ton	$/ton
Feedstock cost	423.00	627.00	186.00	210.00
Production cost:				
Variable cost	551.91	773.30	294.07	322.55
Fixed cost	126.79	146.87	144.89	127.26
Net production cost	678.70	920.17	438.96	449.81

[a] At 90% stream factor.

Table V.5

Investment and production costs for LDPE at four locations in 1980

Product: LDPE

Feedstock: ethylene

Plant capacity[a/]: 200,000 t/a

Daily throughput: 600 t/d

Location	U.S. Gulf Coast	FRG	Arabian Gulf	Mexico
Location factor	1.00	1.15	1.30	1.25
Investment cost:	$ million	$ million	$ million	$ million
Battery limits	99.00	113.90	128.70	123.75
Offsites	39.40	45.30	51.20	49.25
Total	131.40	159.20	179.90	173.00
Working capital	17.04	25.15	12.73	13.62
	$/ton	$/ton	$/ton	$/ton
Feedstock cost	423.00	627.00	184.00	210.00
Production cost:				
Variable cost	492.24[b/]	700.95[c/]	231.19[e/]	274.36[d/]
Fixed cost	131.58	153.91	151.26	142.21
Net production cost	623.82	854.86	382.45	416.57

[a/] At 90% stream factor.

[b/] Excludes by-product credit of $2.23.

[c/] Excludes by-product credit of $20.30.

[d/] Excludes by-product credit of $6.19.

[e/] Excludes by-product credit of $7.80.

Table V.6

Investment and production costs for methanol at four locations in 1980

Product: methanol
Feedstock: methane

Plant capacity[a]: 640,000 t/a
Daily throughput: 2,000 t/d

Location	U.S. Gulf Coast	FRG	Arabian Gulf	Mexico
Location factor	1.00	1.15	1.30	1.25
Investment cost:	$ million	$ million	$ million	$ million
Battery limits	86.50	99.50	112.45	108.12
Offsites	45.30	52.10	58.89	56.62
Total	131.30	151.60	171.34	164.74
Working capital	19.40	20.74	71.78	7.35
	$/ton	$/ton	$/ton	$/ton
Feedstock cost	228.00	223.00	17.00	25.86
Production cost:				
Variable cost	174.91	184.35	26.57	27.52
Fixed cost	38.70	43.85	43.32	40.51
Net production cost	213.61	228.20	69.89	68.03

[a] At 90% stream factor.

Table V.7

Investment and production costs for ammonia at four locations in 1980

Product: ammonia

Feedstock: methane

Plant capacity[a/]: 430,000 t/a

Daily throughput: 1,300 t/d

Location	U.S. Gulf Coast	FRG	Arabian Gulf	Mexico
Location factor	1.00	1.15	1.30	1.25
Investment cost:	$ million	$ million	$ million	$ million
Battery limits	90.20	103.70	117.26	112.75
Offsites	35.50	40.90	46.15	44.37
Total	125.70	144.60	163.41	157.12
Working capital	12.42	13.19	7.05	6.70
	$/ton	$/ton	$/ton	$/ton
Feedstock cost	228.00	223.00[b/]	17.00	25.86
Production cost:				
Variable cost	164.93	171.47	34.22	34.49
Fixed cost	53.85	61.85	60.93	53.13
Net production cost	218.78	233.32	95.15	92.62

a/ At 90% stream factor.

b/ Naphtha feedstock.

Table V.8

Investment and production costs for urea at four locations in 1980

Product: urea

Feedstock: ammonia

Plant capacity[a/]: 680,000 t/a

Daily throughput: 2,000 t/d

Location	U.S. Gulf Coast	FRG	Arabian Gulf	Mexico
Location factor	1.00	1.15	1.30	1.25
Investment cost:	$ million	$ million	$ million	$ million
Battery limits	35.61	40.91	53.41	44.51
Offsites	28.00	32.22	42.00	35.00
Total	63.61	73.13	95.41	79.51
Working capital	12.37	14.46	15.89	12.89
	$/ton	$/ton	$/ton	$/ton
Feedstock cost	219.00	233.00	95.00	93.00
Production cost:				
Variable cost	148.78	159.71	63.20	58.76
Fixed cost	20.03	23.03	22.30	19.18
Net production cost	168.81	182.74	85.50	77.94

a/ At 90% stream factor.

Table V.9.

Investment and production costs for sponge iron at four locations in 1980

Product: sponge iron
Feedstock: iron ore pellets

Plant capacity[a]: 400,000 t/a
Daily throughput: 1,200 t/d

Location	U.S. Gulf Coast	FRG	Arabian Gulf	Mexico
Location factor				
Investment cost:	$ million	$ million	$ million	$ million
Battery limits	...	...	...	...
Offsites	...	...	...	...
Total	72.34	83.2	94.0	90.42
Working capital	...	...	...	...
	$/ton	$/ton	$/ton	$/ton
Feedstock cost	36.92[b]	40.88	40.88	36.92[b]
Production cost:				
Variable cost	118.08[d]	124.74[d]	77.16[e]	80.02[f]
Fixed cost	37.02[g]	28.30[g]	31.05	30.15
Net production cost	155.10	153.04	108.21	110.17

[a] At 90% stream factor.

[b] Ore at $27.60.

[c] Ore at $24.90.

[d] Gas at $4.00/million Btu, power at 40 mills/kWh.

[e] Gas at $0.40/million Btu, power at 10 mills/kWh.

[f] Gas at $0.80/million Btu, power at 20 mills/kWh.

[g] Includes depreciation at 10%. Labour at: U.S. $14.26/h; FRG, $15.97/h; Arabian Gulf, $16.11/h; Mexico, $9.84/h. 9.76 man-hours/ton; plant overhead $64.17/ton.

Table V.10

Investment and production costs for electric furnace steel at four locations in 1980

Product: steel

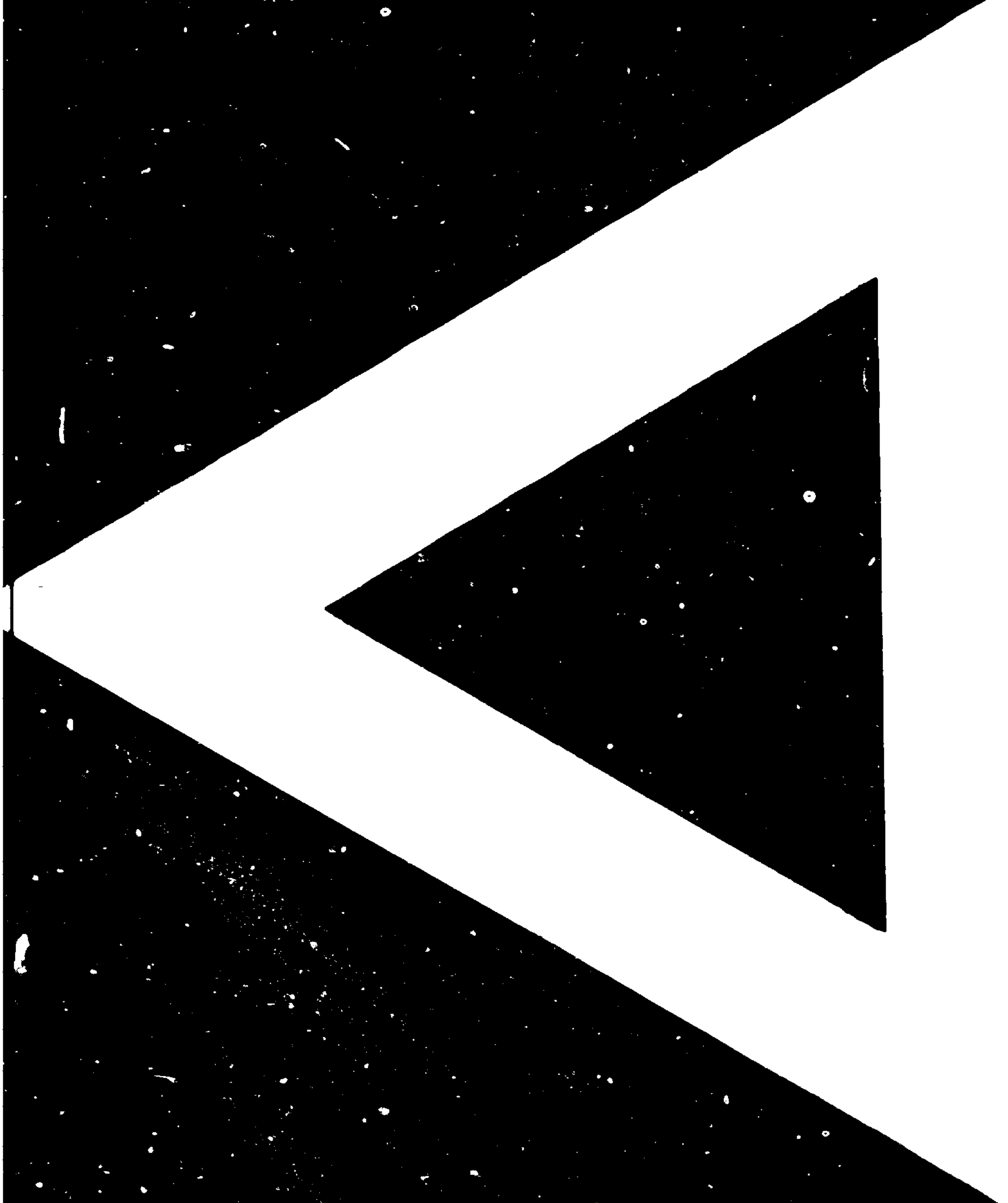
Feedstock: iron ore

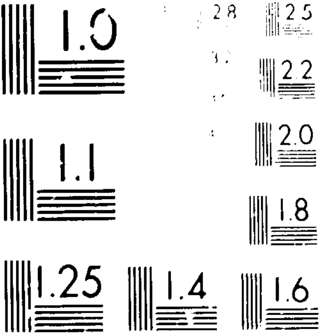
Plant capacity[a]: 400,000 t/a

Daily throughput: 1,200 t/d

Location	U.S. Gulf Coast	FRG	Arabian Gulf	Mexico
Location factor				
Investment cost:	$ million	$ million	$ million	$ million
Battery limits	...	...	...	...
Offsites	...	...	...	...
Total	149.2	171.6	193.9	186.5
Working capital	...	...	...	...
	$/ton	$/ton	$/ton	$/ton
Feedstock cost	369.2 [b]	40.88	40.88 [c]	36.92 [b]
Production cost:				
Variable cost	177.57 [d]	184.27 [d]	94.09 [e]	91.38 [b]
Fixed cost	245.52 [g]	268.31 [g]	275.47	210.16
Net production cost	423.09	452.56	369.56	301.54

[a] At 90% stream factor.
[b] Ore at $27.90/ton.
[c] Ore at $26.90/ton.
[d] Gas at $4.00/million Btu, power at 40 mills/kWh.
[e] Gas at $0.40/million Btu, power at 10 mills/kWh.
[f] Gas at $0.30/million Btu, power at 20 mills/kWh.
[g] Includes depreciation at 10%. Labour at: U.S., $14.26/h; FRG, $15.97/h; Arabian Gulf, $16.11/h; Mexico, $9.84/h. 9.76 man-hours/ton; plant overhead $64.17/ton.




1.0
2.8
2.5
3.2
2.2
3.6
4.0
2.0
1.1
1.8
1.25
1.4
1.6

with

10527

Distr.
LIMITED

UNIDO/PC.11/Corr.1
13 January 1982

ENGLISH

UNITED NATIONS INDUSTRIAL
DEVELOPMENT ORGANIZATION

THE INDUSTRIAL USES OF ASSOCIATED GAS

A Joint Study
by
UNITED NATIONS INDUSTRIAL DEVELOPMENT ORGANIZATION
in co-operation with
GULF ORGANIZATION FOR INDUSTRIAL CONSULTING

Corrigendum

Page 46, table 11, column for ethylene

The entry for Malaysia should read 300 000[a]

The entry for Mexico should read 1 945 000[b],[c]

V.82-20428